Draft decision

New South Wales

draft distribution determination 2009–10 to 2013–14

21 November 2008

AUSTRALIAN ENERGY REGULATOR

Request for submissions

This document sets out the Australian Energy Regulator's (AER) draft distribution determinations for Country Energy, EnergyAustralia and Integral Energy for the period 1 July 2009 to 30 June 2014.

The AER will hold a pre–determination conference on its draft distribution determination for Country Energy on 8 December in Canberra, and a second conference for EnergyAustralia and Integral Energy on 9 December in Sydney. These conferences will be used by the AER to explain its draft determinations and receive oral submissions from interested parties. The pre–determination conference for EnergyAustralia and Integral Energy will be held jointly with the pre–determination conference regarding the AER's draft transmission determination for TransGrid. Interested parties can register to attend the pre–determination conferences by calling the Network Regulation North Branch of the AER on (02) 6243 1233 or by emailing aerinquiry@aer.gov.au by 2 December 2008.

Interested parties are invited to make written submissions on issues regarding these draft distribution determinations and the consultants' reports to the AER by 16 February 2009. The AER will deal with all information it receives in the distribution determination process, including submissions on the draft distribution determinations, in accordance with the ACCC/AER information policy. The policy is available at www.aer.gov.au.

Submissions can be sent electronically to aerinquiry@aer.gov.au

Alternatively, submissions can be mailed to:

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The AER prefers that all submissions be publicly available to facilitate an informed and transparent consultative process. Submissions will be treated as public documents unless otherwise requested. Parties wishing to submit confidential information are requested to:

- clearly identify the information that is the subject of the confidentiality claim
- provide a non–confidential version of the submission.

All non–confidential submissions will be placed on the AER website, www.aer.gov.au.

Copies of Country Energy, EnergyAustralia and Integral Energy's regulatory proposals, proposed negotiating frameworks, consultancy reports and submissions from interested parties are available on the AER website.

Inquiries about the draft distribution determinations or about lodging submissions should be directed to the Network Regulation North Branch on (02) 6243 1233.

Contents

Shortened forms

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CPI	consumer price index
current regulatory control period	1 July 2004 to 30 June 2009
DNSP	distribution network service provider
IPART	Independent Pricing and Regulatory Tribunal
NEL	National Electricity Law
NEM	national electricity market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
next regulatory control period	1 July 2009 to 30 June 2014
NSW DNSPs	Country Energy, Integral Energy and EnergyAustralia
opex	operating expenditure
Wilson Cook	Wilson Cook and Co. Limited

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Overview

A transition to a new regulatory framework

Under the National Electricity Law (NEL) and the National Electricity Rules (NER), the Australian Energy Regulator (AER) is responsible for the economic regulation of electricity distribution services provided by distribution network service providers (DNSPs) in the national electricity market (NEM).

The AER's draft distribution determinations for the NSW DNSPs for the 2009–14 regulatory control period are one of the first distribution determinations to be made by the AER under the NEL and NER. The draft determinations that apply to Country Energy, EnergyAustralia and Integral Energy are being made under transitional provisions set out at part M of chapter 11 of the NER (the transitional chapter 6 rules) which incorporate key aspects of the new general chapter 6 rules, but also lock in certain aspects of the current distribution determination made by the NSW regulator, the Independent Pricing and Regulatory Tribunal (IPART).

The AER's considerations in making its draft determinations on the efficient levels of the NSW DNSP's capital and operating expenditures for the next regulatory control period mirror the new chapter 6 rules. The transitional chapter 6 rules require the AER to maintain the weighted average price cap (WAPC) form of control and classification of services established by IPART in its 2004 distribution determination for the current regulatory control period. The transitional chapter 6 rules also establish parameters which the AER must use to determine the weighted average cost of capital.

At the time of IPART's 2004 distribution determination, the NER required an assessment of the prudence of the NSW DNSPs' capital expenditures as part of the process of setting the closing regulatory asset bases (RAB). The transitional chapter 6 rules remove this obligation for the AER's determination for the next regulatory control period. However, as part of the process of determining the reasonableness of the forecast capital expenditures in the next regulatory control period, the AER reviewed the reasons for variations between forecast and actual capital expenditure over the current regulatory control period.

Review process

In making its draft determinations, the AER assessed each NSW DNSP's regulatory proposal to determine if it was in accordance with the requirements of the NER. Expert engineering consultants, as well as financial and economic experts assisted the AER in making its assessment. The AER has considered the past performance of each NSW DNSP and the effectiveness of each NSW DNSPs' policies and procedures, both in terms of past performance and in the development of their respective regulatory proposals.

The process of assessing the NSW DNSPs' regulatory proposals commenced in June 2008. Prior to that time, the AER, in consultation with the NSW DNSPs, developed a regulatory information notice (RIN), including information templates, which support the regulatory proposals. These information templates allowed the

NSW DNSPs' regulatory proposals to be made in broadly consistent terms and allowed comparisons to be made regarding the key drivers underpinning the expenditure proposals.

Following its receipt of the NSW DNSPs' regulatory proposals, the AER conducted a preliminary assessment to establish that they complied with cost allocation principles, and that asset values and revenue models had been correctly applied in accordance with the requirements of the RINs and the NER. Following this initial assessment, the NSW DNSP's regulatory proposals was published on the AER's website, and submissions were sought from interested parties. The AER received 54 submissions on the NSW DNSPs' regulatory proposals. The majority of these submissions were made in relation to public lighting. The AER's consideration of these submissions forms part of this draft decision.

The detailed examination of the NSW DNSP's regulatory proposals was informed by advice from Wilson Cook and Co. Limited (Wilson Cook). Wilson Cook is an engineering and management consultancy firm, and has considerable experience in reviewing the performance and operating requirements of the NSW DNSPs. Wilson Cook previously performed this role for IPART's 2004 distribution review. Wilson Cook reviewed the regulatory proposals and supporting data supplied by the NSW DNSPs throughout the review process. In addition, during the review Wilson Cook and AER staff inspected supporting documentation such as planning documents, manuals and financial models. As part of this process, senior staff within each of the NSW DNSPs were questioned in relation to the assumptions underpinning the regulatory proposal and its implementation. This process assisted Wilson Cook and the AER to satisfy itself that the regulatory proposals were soundly based and that appropriate policies and procedures had been established to deliver the proposed capital works.

Wilson Cook assessed the regulatory proposals to establish the necessity of the proposed expenditure and the reasonableness of expected costs. This included a bottom up assessment of each of the NSW DNSP's proposed programs and unit costs, as well as benchmark assessments of programs against historical costs and comparative performance of operating expenditures against that of other DNSPs.

Wilson Cook's assessment of the regulatory proposals confirmed the need for substantial increases in capital works for each of the NSW DNSPs over the next regulatory control period. Among other reasons, increases in capital works are needed to augment the networks to accommodate the growth in maximum demand for energy, to replace ageing assets and to improve network security and reliability.

The need for increased expenditure to ensure network security and reliability has been reinforced by changes to NSW DNSP licence conditions, necessitating increased capital expenditure by the NSW DNSPs. This is most noticeable for EnergyAustralia and Country Energy. The new licence conditions impose a requirement on EnergyAustralia to meet an N-2 security of supply requirement for the Sydney CBD. Meeting this standard will result in expenditures in the order of $333 million ($2008–09 real). Country Energy will also need to enhance its network to improve the security of supply of subtransmission and major zone substations and subtransmission feeders with load in excess of 15 MVA. This will require expenditure in the order of $216 million during the next regulatory control period.

The AER has largely accepted the reasons provided by the NSW DNSPs to increase their capital programs. In some cases the AER determined that proposed programs did not fully meet the capital expenditure requirements of the transitional chapter 6 rules, and the AER accordingly made a deduction from the allowance proposed by the respective NSW DNSP. While the AER has largely accepted the NSW DNSPs' needs to construct new or replace existing assets, it has not accepted the basis on which the NSW DNSPs sought to estimate the likely future costs of constructing these assets. The AER has compared the NSW DNSPs' proposals to its own estimates of the likely future costs of the proposed capital expenditure programs.

As part of a recent electricity transmission determination, the AER developed a methodology to assess likely increases in the costs of materials. This methodology sought to ensure that the affect of the commodities boom on metals' prices and labour costs—key inputs for the energy sector—was fully factored into regulatory determinations. Within their regulatory proposals, the NSW DNSPs sought to modify the AER's escalation methodologies. For the reasons set out in this draft decision, the AER has not accepted the proposed modifications for estimating material and labour cost escalators. The AER, however, will review the data used to estimate cost escalators as part of its final determinations, to be made by 30 April 2009.

After assessing each of the NSW DNSP's proposals against the capital expenditure criteria in the transitional chapter 6 rules, the AER has determined that the capital expenditure allowance proposed by each of the NSW DNSPs is greater than the amount needed to meet the capital expenditure criteria in the NER. The AER has determined that:

- Country Energy's proposed capital expenditure is $53 million greater than an efficient level. The AER's draft determination amounts to an 1.3 per cent reduction in the proposed capital expenditure

- EnergyAustralia's proposed capital expenditure is $223 million greater than an efficient level. The AER's draft determination amounts to an 2.6 per cent reduction in the proposed capital expenditure

- Integral Energy's proposed capital expenditure is $39 million greater than an efficient level. The AER's draft determination amounts to an 1.3 per cent reduction in the proposed capital expenditure.

Wilson Cook assessed the NSW DNSPs' operating expenditure proposals, and confirmed a need for higher operating expenditures over the next regulatory control period. Higher operating expenditures are resulting from the increased size of the networks, as well as higher material and labour costs.

In the ten years to 2007–08, real wages growth in the electricity, gas and water sector in NSW exceeded growth in economy-wide real wages by an average of 0.8 per cent per annum. Labour costs in the utilities sectors are forecast to continue to exceed the economy-wide average over the course of the next regulatory control period. After assessing each of the NSW DNSP's proposals against the operating expenditure criteria in the transitional chapter 6 rules, the AER has determined that the operating expenditure allowance proposed by each of the NSW DNSPs is greater than the amount needed to meet the operating expenditure criteria in the NER. The AER has determined that:

- Country Energy's operating expenditure allowance for the next regulatory control period is to be set at $1975 million, representing a reduction of 8.6 per cent on the total amount proposed
- EnergyAustralia's operating expenditure allowance for the next regulatory control period is to be set at $2638 million, representing a reduction of 13 per cent on the total amount proposed
- Integral Energy's operating expenditure allowance for the next regulatory control period is to be set at $1460 million, representing a reduction of 1.2 per cent on the total amount proposed. The AER has not reduced Integral Energy's controllable operating expenditure components and notes its actions to improve productivity during the next regulatory control period.

Outcome of regulatory process

Over the course of the next regulatory control period, the NSW DNSPs will significantly increase investment on their networks, and improve network security and reliability of supply in line with the new licence conditions imposed by the NSW Government.

An outcome of the AER's draft determinations will be significantly higher prices for electricity consumers in NSW. The percentage price increase will be the greatest in 2009, reflecting the fact that the NSW DNSPs overspent their capital allowances in the previous regulatory control period. Prices will rise modestly in real terms in each year of the regulatory control period in line with increased investment and higher operating costs.

The increase in network charges is not uniform across the NSW DNSPs. This reflects the specific circumstances faced by each of the NSW DNSP's, which is discussed in this draft decision. The average retail customer's annual electricity charge in 2009 is likely to increase by:

- 7.9 per cent for customers connected to Country Energy's network
- 10 per cent for customers connected to EnergyAustralia's network
- 6.2 per cent for customers connected to Integral Energy's network.

In part, higher electricity charges are also a result of maximum demand on the networks growing at a faster rate than overall energy consumption. The need to expand the network to meet higher peaks in demand reduces the efficiency of the network and increases the cost of supplying electricity. Over the next regulatory control period, maximum demand on the NSW distribution networks is expected to increase by approximately 3 per cent per annum. By contrast, energy consumption is expected to increase by 1.3 per cent per annum. The increasing discrepancy between maximum demand and energy consumption growth reduces the overall efficiency of the networks and increases the need for effective and reliable demand management.

The AER's draft decision supports the NSW DNSPs' development of innovative responses to rising demand on the network through the application of two demand management incentive schemes, the demand management innovation allowance and the D-factor schemes.

The global financial crisis may impact on the price of electricity by raising the weighted average cost of capital used to determine the NSW DNSPs' allowed revenues. The cost of capital has fluctuated from around 9 per cent in early 2007, up to around 11 per cent in mid-2008. However, since then the cost of capital has fallen to 9.72 per cent, as at 17 October 2008. The cost of capital used to determine future revenues will be determined closer to the time of the AER's final determinations. If global financial conditions improve in the interim period, and the commercial debt risk premium subsequently declines this will be reflected in a lower cost of capital for the NSW DNSPs, and lower electricity prices for consumers.

Summary

Introduction

In 2004, the Independent Pricing and Regulatory Tribunal (IPART) determined weighted average revenue caps for each NSW DNSP (distribution network service providers) for a five year period from 1 July 2004 to 30 June 2009.

The AER assumed responsibility for regulating electricity distribution services provided by the NSW DNSPs from 1 January 2008. The distribution determinations for the period 1 July 2009 to 30 June 2014 (the next regulatory control period) is the first for the NSW DNSPs to be conducted by the AER under the National Electricity Rules (NER).

The transitional chapter 6 rules took effect on 1 January 2008. The AER must make a distribution determination for the NSW DNSPs according to these rules and with reference to the AER's transitional guidelines for the ACT and NSW.

The AER published the NSW DNSPs' regulatory proposals and proposed negotiating frameworks on 26 June 2008. Interested parties were invited to make submissions on all these proposals and 43 submissions were received. The NSW DNSPs presented their regulatory proposals at a public forum held in Sydney on 30 July 2008.

The AER engaged the following consultants to assist in the assessment of the regulatory proposals:

- Wilson Cook and Co. Limited (Wilson Cook) as a technical engineering expert
- Energy and Management Services Pty Ltd (EMS) to provide additional expert engineering advice
- Econtech to provide wage growth forecasts.

This draft decision should be read in conjunction with these consultants' reports, which are available on the AER's website.

The key decisions addressed in this draft decision are:

- the opening regulatory asset base (RAB) values for the NSW DNSPs
- the AER's assessment of the NSW DNSPs forecast capital expenditure (capex) programs
- the AER's assessment of the NSW DNSPs forecast operating expenditure (opex) programs
- an estimate of the efficient benchmark weighted average cost of capital (WACC) for the NSW DNSPs
- the NSW DNSPs' annual revenue requirement for each year of the next regulatory control period

- the AER's decision regarding the NSW DNSPs' proposed negotiating frameworks for negotiable components of direct control services
- the AER's proposed negotiable component criteria (NCC) that will apply to the NSW DNSPs.

The AER's consideration of each of these components is summarised below. Further detail is provided in the relevant chapters and in the appendices attached to this draft decision.

Regulatory requirements

National Electricity Law

The National Electricity Law (NEL) sets out the functions and powers of the AER, including its role as the economic regulator of the National Electricity Market (NEM). The NEL states that when performing or exercising a regulatory function or power, the AER must do so in a manner that will or is likely to contribute to the achievement of the national electricity objective. The national electricity objective under the NEL is:

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to
>
> (a) price, quality, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

National Electricity Rules

The transitional chapter 6 rules of the NER set out the provisions the AER must apply in exercising its regulatory functions and powers for the NSW and ACT DNSPs providing direct control services and negotiated distribution services.

Broadly, the transitional chapter 6 rules:

- specify the classification of services that the AER is to apply—based on IPART's classification that applies in the current regulatory control period.
- require the AER to assess the DNSP's negotiable components of direct control services and negotiating framework
- require the AER to propose negotiable component criteria
- require the AER to assess the DNSP's control mechanism for standard control services
- set out the methodology for establishing the opening RAB
- require the AER to assess the DNSP's demand forecasts and cost inputs to achieve the capex objectives

- set out the requirements for the DNSPs' revenue proposals, including the requirement to forecast capex and opex necessary to meet the capex and opex objectives. These objectives include meeting the expected demand for standard control services, complying with all regulatory obligations or requirements and maintaining the quality, reliability and security of supply of standard control services and the reliability, safety and security of the distribution system through the supply of the standard control services

- require the AER to assess whether the forecast capex and opex proposed by a DNSP reflect the efficient costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the capex or opex objectives

- set out the methodology for calculating the estimated corporate income tax

- set out the methodology for calculating depreciation on the assets to be included in the RAB and require the AER to assess whether or not to approve the depreciation schedules submitted by a DNSP

- set out the methodology for calculating the cost of capital

- provide that the AER may develop and publish service target performance incentive scheme, efficiency benefit sharing scheme and demand management incentive scheme

- require the AER to assess pass through events

- require the AER to specify the DNSP's annual revenue requirement for each year of the regulatory control period and to set the X factor for each year of the regulatory control period

- set out the form of control the AER may apply to alternative control services

- require the AER to assess whether EnergyAustralia's prescribed (transmission) standard control services pricing methodology complies with the NER.

The relevant regulatory requirements set out under the transitional chapter 6 rules are outlined in detail at the beginning of each chapter in this draft decision.

Classification of services

NSW DNSP proposals

EnergyAustralia

EnergyAustralia is the only NSW DNSP proposing to reclassify its distribution services under the NER. EnergyAustralia has proposed reclassification of metering services (types 1–4), customer funded connections and customer specific services to unclassified services. In relation to metering services (types 1–4) and customer funded connections, EnergyAustralia's rationale is that such services are contestable.

EnergyAustralia has also proposed that emergency recoverable works be reclassified from a standard control service (prescribed distribution service) to an unclassified service.

It argued that customer specific services and emergency recoverable works are not a distribution service and should not be regulated.

AER conclusion

The AER does not accept EnergyAustralia's proposal that customer specific services and emergency recoverable works are not distribution services. The AER does not accept EnergyAustralia's proposed reclassification of metering services (types 1–4), customer funded connections, customer specific services and emergency recoverable works. The AER does not consider EnergyAustralia to have provided sufficient justification to satisfy the AER that these services be reclassified to an unclassified service and not be subject to regulation. The AER will implement the deemed classification of services for EnergyAustralia as provided for in the NER.

The AER will implement the deemed classification of services for Country Energy and Integral Energy as provided for in the NER.

Arrangements for negotiation

Negotiable components

NSW DNSP proposals

Country Energy

Country Energy submitted that it had no negotiable components of direct control services, and consequently did not initially provide a negotiating framework. However, following a request from the AER, Country Energy provided a proposed negotiating framework.

EnergyAustralia

EnergyAustralia did not propose any negotiable components of direct control services as it considered that there is only limited scope for negotiation in relation to direct control services and that it is difficult to define in advance which components will be negotiable. However, EnergyAustralia proposed a definition with examples to assist in identifying negotiable components of direct control services, rather than specifically identifying negotiable components.

EnergyAustralia suggested that a negotiable component of a direct control service should be any component (or a condition of the service) where some variability can be applied to the provision of the direct control service without interfering with or in any way compromising a DNSP's ability to comply with any regulatory obligation or requirement of the NER.

Integral Energy

Integral Energy proposed that the following components be classified as negotiable components of direct control services under the NER:

1. a direct control service that exceeds the network performance requirements which that direct control service is required to meet under any jurisdictional electricity legislation;
2. a direct control service that, except to the extent of any prescribed requirements of jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or 5.1 of the NER;
3. a direct control service that is a connection service provided to serve network users at a single distribution network connection point, other than connection services that are provided by one network service provider to another network service provider to connect their networks where neither provider is a market network service provider; or
4. the terms and conditions in respect of which any of the above are provided.

AER conclusion

The AER has decided not to specify any particular components of the NSW DNSPs' direct control services as negotiable components for the next regulatory control period. However, the AER has decided to define a negotiable component of a direct control service as any component of a direct control service (or the terms and conditions on which that direct control service or component are provided) where:

- the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation;
- the direct control service, except to the extent of any prescribed requirements of jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or 5.1 of the NER; or
- the direct control service is a connection service provided to serve network users at a single distribution network connection point, other than connection services that are provided by one network service provider to another network service provider to connect their networks where neither provider is a market network service provider.

Therefore, components that fall within the scope of the above definition, are negotiable components.

Negotiable component criteria

NSW DNSP proposals

EnergyAustralia

EnergyAustralia supported the AER adopting the negotiable component principles in the NER as the appropriate criteria. EnergyAustralia noted the negotiated transmission service criteria determined in the AER's recent ElectraNet decision adopted the relevant principles from chapter 6A as the criteria without any additional matters.

AER conclusion

In light of EnergyAustralia's submission, the AER will change the heading of criterion 1 from 'national electricity market objective' to 'national electricity objective'. The AER does not accept the other changes proposed by EnergyAustralia.

Negotiating framework

NSW DNSP proposals

EnergyAustralia submitted a proposed negotiating framework to cover both negotiable components of direct control services and its negotiated distribution services as contemplated by the NER.

Integral Energy and Country Energy submitted their proposed negotiating framework for negotiable components of direct control services.

All three proposed negotiating frameworks are substantially similar and have been assessed together where there are joint issues.

AER conclusion

As required by the NER, the AER approves the NSW DNSPs negotiating frameworks to apply for the next regulatory control period. Country Energy's, EnergyAustralia's and Integral Energy's negotiating frameworks are in appendices D, E and F respectively. The AER considers that the negotiating frameworks comply with part DA of the transitional chapter 6 rules and, in the case of EnergyAustralia's negotiating framework, part D of the transitional chapter 6 rules.

Control mechanism for standard control services

NSW DNSP proposals

Country Energy

Country Energy calculated its revenue requirements and X factors for standard control services under a WAPC control mechanism. Country Energy proposed a schedule of fixed charges for miscellaneous and monopoly services for 2008–09 which are to be escalated and form part of the WAPC. A schedule of prices was not provided for emergency recoverable works.

Country Energy noted that the AER's proposed approach to determining a schedule of charges for miscellaneous and monopoly services and emergency recoverable works is consistent with the approach adopted by IPART for the current regulatory control period. However, Country Energy stated that in future these charges should be analysed to ensure they are cost reflective although it acknowledges that timing constraints (of the current review) require a need for simplicity in the charges for these services.

EnergyAustralia

EnergyAustralia stated that it has prepared its control mechanism in accordance with the AER's standard control services guideline. However, it proposed the following departures:

- a variation in the treatment of miscellaneous fees and monopoly charges
- a minor amendment to the expression of the WAPC formula
- an amendment to the calculation of the X factor with respect to D factor and other incentive payments as it affects compliance with side constraints
- the exclusion of emergency recoverable works. It stated emergency recoverable works is not a distribution service and should not be regulated under the rules. If classified as a distribution service, emergency recoverable works should be reclassified from a standard control service to an unclassified service.

EnergyAustralia proposed to maintain the arrangements which were put in place by IPART for the review and submission of the WAPC and TUOS quantities to demonstrate compliance with the WAPC constraint and TUOS pass through calculations. It also proposed continuation of IPART's approach for using reasonable estimates to account for tariff restructuring.

Integral Energy

Integral Energy calculated its revenue requirements and X factors for standard control services under a WAPC control mechanism. It raised specific issues with the TUOS pass throughs, the application of side constraints and the calculation of miscellaneous and monopoly services charges.

Integral Energy sought clarification from the AER about whether it will use actual data to calculate the TUOS overs and unders amount from 2011–12 onwards. It noted the AER previously stated that it would use actual data where available from the current regulatory control period to determine the TUOS overs and unders adjustment for each regulatory year. Integral Energy supported the use of actual data as it eliminates forecasting risk.

Integral Energy accepted the approach to side constraints set out in the AER's standard control services guideline. However, it expressed concern about whether the wording of the NER allows such an approach as it implies that both price and volume changes need to be considered when assessing movements within the side constraint.

Integral Energy proposed to increase prices for monopoly and miscellaneous services by the cumulative CPI from 2004–09 (14.4 per cent) and then index the prices by the annual CPI throughout the regulatory control period.

For emergency recoverable works, Integral Energy proposed to use the pricing principles applied by the IPART 2004–09 determination. These principles are:

- Integral Energy must not charge more than 110 per cent of the actual costs of materials and plant associated with the repairs; plus
- No more than 150 per cent of the actual labour costs associated with the repair, when calculated at the R2b (Inspector) hourly rate ($72 per hour).

AER conclusion

The AER will apply the following WAPC formula to the NSW DNSPs standard control services for the next regulatory control period:

$$\frac{\sum_{i=1}^{n}\sum_{k=1}^{m} p_{ik}^{t} \times q_{ik}^{t-2}}{\sum_{i=1}^{n}\sum_{k=1}^{m} p_{ik}^{t-1} \times q_{ik}^{t-2}} \leq (1+\Delta CPI)\times(1-X_t)\times(1+D_t) \qquad \mathrm{i}=1,\ldots,\mathrm{n} \text{ and } \mathrm{k}=1,\ldots,\mathrm{m}.$$

The AER will apply the following side constraint formula to each tariff class of standard control services provided by the NSW DNSPs:

$$\frac{\sum_{k=1}^{m} d_k^t \times q_k^{t-2}}{\sum_{k=1}^{m} d_k^{t-1} \times q_k^{t-2}} \leq 1 + \Delta CPI + L_t \qquad \mathrm{k}=1,\ldots,\mathrm{m}.$$

The AER has decided that the schedule of fees and/or charges for miscellaneous services, monopoly services and emergency recoverable works for the next regulatory period is set out in appendix H of this decision. The schedule of charges that apply under the IPART 2004–09 determination have been escalated to take into account CPI movements over the current regulatory control period and an estimate for CPI movements in the next regulatory control period. The escalation will be updated to reflect actual CPI at the time of the final decision.

The AER will apply the following revenue cap formula to EnergyAustralia prescribed (transmission) standard control services:

$$MAR = (AR_t) \pm \left[\frac{(AR_{t-1} + AR_{t-2})}{2} \times S_{ct}\right] \pm (\textit{pass through})$$

Opening regulatory asset base

NSW DNSP proposals

Country Energy

Country Energy proposed an opening RAB for the next regulatory control period of $4236 million as at 1 July 2009. The proposed opening RAB includes capex of $2206 million incurred during the current regulatory control period.

The proposed RAB includes downward adjustments of $10 million for the difference between actual and forecast capex in 2003–04 and the associated return on that difference, and $35 million for asset disposals over the current regulatory control period. Further, an adjustment of $477 million has been made for depreciation based on the actual capex. There is an additional upward adjustment to the proposed RAB of $112 million for deferred depreciation, which was allowed for by the 2004 IPART determination. The proposed opening RAB has also been indexed for actual inflation using the consumer price index (CPI).

Country Energy also provided information to support an increase to its proposed opening RAB of $296 million for assets omitted from the previous RAB valuation. Country Energy stated that ‘a number of material inaccuracies existed in the initial 1999 asset valuation, and these have perpetuated through into subsequent roll forward valuations.’ Country Energy did not include the $296 million for omitted assets in its proposed RAB within the roll forward model (RFM) or post-tax revenue model (PTRM).

EnergyAustralia

EnergyAustralia proposed an opening RAB for the next regulatory control period of $8218 million as at 1 July 2009. This is comprised of $7229 million for its distribution opening RAB and $989 million for its transmission opening RAB. The proposed distribution opening RAB includes capex of $3390 million incurred during the current regulatory control period.

The proposed distribution RAB includes downward adjustments of $43 million for the difference between actual and forecast capex in 2003–04, and the associated return on that difference, and $55 million for asset disposals over the current regulatory control period. The distribution RAB has also been reduced by depreciation of $333 million based on the actual capex incurred during the current regulatory control period and an adjustment of $57 million for system assets moved from distribution to transmission.

For transmission assets, the proposed opening RAB includes capex of $348 million and has been reduced by depreciation of $37 million based on the actual capex incurred during the current regulatory control period. It also includes downward adjustments of $3 million for asset disposals and $15 million for non–system asset relocation. A further adjustment of $57 million for the assets transferred from distribution increases the transmission RAB.

Integral Energy

Integral Energy proposed an opening RAB for the next regulatory control period of $3835 million as at 1 July 2009. The proposed opening RAB includes capex of $1956 million, net of capital contributions, incurred during the current regulatory control period.

The proposed RAB includes downward adjustments of $46 million for asset disposals and $434 million for depreciation based on the actual capex. It has also been adjusted downwards by $95 million for the difference between actual and forecast capex in 2003–04, and the associated return on that difference over the current regulatory control period.

Integral Energy proposed an increase of $170 million for erroneous asset lives applied to its opening RAB. This issue was considered and not approved as part of the 2004 IPART determination. This figure was not included in the RFM by Integral Energy. However, Integral Energy adjusted the opening RAB value in the PTRM to include the $170 million adjustment.

AER conclusion

Country Energy

The RAB roll forward calculations for Country Energy are set out in table 1 and provide for an opening RAB of $4247 million for the next regulatory control period (as at 1 July 2009).

Table 1: Country Energy's opening RAB for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	2439.0	2638.4	2920.0	3323.8	3724.8
Actual net capex (adjusted for actual CPI and WACC)[c]	276.7	366.7	473.2	522.6	645.1
CPI adjustment on opening RAB	57.2	70.4	103.3	77.5	111.7
Straight-line depreciation (adjusted for actual CPI)	–134.5	–155.6	–172.7	–199.2	–225.0
Closing RAB	2638.4	2920.0	3323.8	3724.8	4256.6
Less: difference between actual and forecast capex for 2003–04					5.7
Less: return on difference[d]					3.5
Opening RAB at 1 July 2009					4247.5

(a) Based on estimated net capex
(b) Based on forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.
(c) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The cash values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $5.7 million for 1 July 2003 to 30 June 2004.

The AER has decided that the opening RAB should not include omitted assets as proposed by Country Energy. Accordingly, the proposed addition of $296 million is not included in the opening RAB as at 1 July 2009. The AER will update the roll forward of Country Energy's RAB with actual capex for 2007–08 and the most recent forecast of capex for 2008–09, and the latest actual CPI data at a time closer to its final distribution determination.

EnergyAustralia

The RAB roll forward calculations for EnergyAustralia are set out in tables 2 and 3, and provide for a distribution opening RAB of $7203 million and a transmission opening RAB of $985 million for the next regulatory control period (as at 1 July 2009). The combined distribution and transmission opening RAB as at 1 July 2009 is $8188 million. The AER will update the roll forward of EnergyAustralia's RAB with actual capex for 2007–08 and the most recent forecast of capex for

2008–09, and the latest actual CPI data at a time closer to its final distribution determination.

Table 2: EnergyAustralia's revised opening RAB (distribution) for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	4064.0	4428.2	4914.6	5625.0	6368.1
Actual net capex (adjusted for actual CPI and WACC)[c]	432.7	549.9	740.5	846.4	927.2
CPI adjustment on opening RAB	95.2	118.2	173.9	131.2	177.4
Straight-line depreciation (adjusted for actual CPI)	–163.8	–181.7	–204.1	–234.4	–271.0
Closing RAB	4428.2	4914.6	5625.0	6368.1	7201.8
Add: difference between actual and forecast capex for 2003–04					26.7
Add: return on difference[d]					16.1
Less: system assets moving from distribution to transmission					57.2
Add: non–system asset re-allocation					15.4
Opening RAB at 1 July 2009					7202.8

(a) Based on estimated net capex.
(b) Based on estimated net capex and forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.
(c) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The cash values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $26.7 million for 1 July 2003 to 30 June 2004.

Table 3: EnergyAustralia's opening RAB (transmission) for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	635.6	663.0	698.9	725.7	777.9
Actual net capex (adjusted for actual CPI and WACC)[c]	39.0	44.7	40.8	54.5	169.0
CPI adjustment on opening RAB	15.0	19.8	17.0	30.8	33.0
Straight-line depreciation (adjusted for actual CPI)	–26.7	–28.6	–31.0	–33.1	–36.9
Closing RAB	663.0	698.9	725.7	777.9	943.0
Add: system assets moving to transmission from distribution					57.2
Less: non–system asset re-allocation					15.4
Opening RAB at 1 July 2009					984.8

(a) Based on estimated net capex.
(b) Based on estimated net capex and forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.
(c) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The accounting book values for disposal of assets have been deducted.

Integral Energy

The RAB roll forward calculations for Integral Energy are set out in table 4 and provide for an opening RAB of $3678 million for the next regulatory control period (as at 1 July 2009).

Table 4: Integral Energy's opening RAB for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	2283.5	2454.1	2706.5	3019.7	3317.0
Actual net capex (adjusted for actual CPI and WACC)[c]	248.5	330.0	376.1	404.3	552.0
CPI adjustment on opening RAB	53.5	65.5	95.8	70.4	99.5
Straight-line depreciation (adjusted for actual CPI)	–131.3	–143.2	–158.7	–177.4	–196.4
Closing RAB	2454.1	2706.5	3019.7	3317.0	3772.2
Less: difference between actual and forecast capex for 2003–04					58.6
Less: return on difference[d]					35.7
Opening RAB at 1 July 2009					3677.8

(a) Based on estimated next capex
(b) Based on estimated forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.
(c) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The accounting book values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $58.6 million for 1 July 2003 to 30 June 2004.

The AER has decided not to approve Integral Energy's proposed increase to the opening RAB of $170 million to correct erroneous asset lives used in the historical valuation of sub–transmission and zone substations. The AER will update the roll forward of Integral Energy's RAB with actual capex for 2007–08 and the most recent forecast of capex for 2008–09, and the latest actual CPI data at a time closer to its final distribution determination.

Demand forecasts

NSW DNSP proposals

Country Energy

Country Energy based its load driven capex forecasts on maximum demand at 50 per cent probability of exceedence (POE). For the first year of the 2009–14 regulatory control period, maximum demand for Country Energy's network as a whole is expected to occur in winter, however, in 2010–11 Country Energy has forecast its network to transition from winter to summer peaking. This is reflected in table 5.

Table 5: Country Energy's energy and maximum demand forecasts 2009–10 to 2013–14

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14
Energy sales (base) – MWh	12506 800	12768 530	13019 560	13151 620	13291 920	1.6%
Winter maximum demand (50% POE) – MW	2405	2461	2515	2551	2589	1.8%
Summer maximum demand (50% POE) – MW	2404	2484	2583	2653	2728	3.0%

Source: Country Energy, *Regulatory proposal*, proformas, confidential, table 2.3.8.
Note: Shaded values represent system maximum demand for that year.

Country Energy engaged a consultant, the National Institute of Economic and Industry Research (NIEIR) to develop its maximum demand, energy and customer number forecasts.

EnergyAustralia

EnergyAustralia forecast demand for its standard control services over the next regulatory control period using global (at network level, or top–down), and spatial (at each zone and sub–transmission substation, or bottom–up) forecasts. The global peak demand forecasts were used as a check of the reasonableness of the peak demand growth forecasts implicit in the spatial forecasts.

EnergyAustralia's network is summer peaking, at 50 per cent POE. Its energy and maximum demand forecasts are provided in table 6.

Table 6: EnergyAustralia's energy and maximum demand forecasts 2009–10 to 2013–14

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14
Energy sales (base) – MWh	28 466 305	28 985 908	29 455 415	29 736 470	30 136 072	1.6%
System maximum demand (50% POE) – MW[a]	6205	6378	6550	6722	6894	2.8%

Source: EnergyAustralia, *Regulatory proposal*, proformas, confidential, table 2.3.8.
(a) Values are for summer peak demand.

Integral Energy

Integral Energy based its load driven expenditure forecasts on maximum demands at 50 per cent POE. Integral Energy's network is predominantly summer peaking, and is being affected by an increasing number of high temperature events and lower equipment ratings during summer periods. This is reflected in table 7.

Table 7: Integral Energy's energy and maximum demand forecasts 2009–10 to 2013–14

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14
Energy sales (base) – MWh	17 927 126	18 159 695	18 460 434	18 664 476	18 905 646	1.3%
System maximum demand (50% POE) – MW[a]	4179	4342	4509	4663	4822	3.5%

Source: Integral Energy, *Regulatory proformas*, confidential, table 2.3.8.
(a) Values are for summer peak demand.

Integral Energy engaged CRA to review all material underlying assumptions and methodologies used in its peak demand, energy consumption and customer number forecasts for its regulatory proposal. As a result of this review, Integral Energy made some revisions to its assumptions and methodologies applied within its forecasts for the next regulatory control period.

AER conclusion

The AER considers Country Energy's and EnergyAustralia's maximum demand forecast methodologies and forecasts provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the NER.

The AER considers that the maximum demand forecast within Integral Energy's regulatory proposal does not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the NER. The AER's draft decision is to accept Integral Energy's revised maximum demand forecast provided on 29 August 2008.

The AER considers EnergyAustralia's and Integral Energy's revised energy and customer number forecast methodologies reasonable, however, it considers that the forecasts (which were provided to the AER on 29 and 31 respectively 2008) should be updated to take into account the most recent energy sales data, once audited data for regulatory year 2007–08 becomes available. Accordingly, the AER requests that a revised energy forecast be submitted to the AER for consideration in its final distribution determination. The AER also requests that Country Energy provide revised energy and customer number forecasts for consideration in the final distribution determination.

The revised energy forecasts are to use the audited energy data for 2007–08 as a starting point. The new data is to be weather corrected and allocated according to the methodology applied in generating the original energy forecast. The new energy forecast should incorporate the revised customer number forecasts provided by EnergyAustralia and Integral Energy in late October 2008. Country Energy's revised energy forecast should incorporate a revised customer number forecast, which is to use actual customer numbers as at 30 June 2008 as the starting point for the forecast, then escalated at the NIEIR recommended base–case forecast for the remaining years of the next regulatory control period.

The AER requests that the NSW DNSPs provide their revised forecasts as updated versions of the forecast sales quantities table within the 'Input' sheet of the PTRM, by COB on 20 February 2009.

Forecast capital expenditure

NSW DNSP proposals

The NSW DNSPs proposed a total forecast capex requirement of $15.6 billion ($2008–09) for the next regulatory control period, which represents an increase nearly double that of the current regulatory control period. An overview of the DNSP's capex forecasts is provided below. Further details of the capex proposals are provided at appendices K, L and M.

Country Energy

Country Energy proposed a capex allowance totalling $4008 million ($2008–09) for the next regulatory control period. Table 8 sets out Country Energy's proposed capex by category.

Table 8: Country Energy's capex proposal by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Growth	247.3	272.3	287.6	298.5	310.7	1416.5
Asset renewal/replacement	137.2	153.3	163.6	171.5	180.6	806.1
Reliability and quality of service enhancement	164.2	177.0	182.9	185.7	188.9	898.9
Environmental, safety and statutory obligations	35.5	39.0	41.3	42.9	44.6	203.3
Total system	584.2	641.7	675.4	698.6	742.9	3324.6
Non–system assets	167.8	137.3	130.6	123.4	124.6	683.6
Total	752.0	779.0	806.0	822.0	849.5	4008.4

Source: Country Energy, global capex model; Country Energy, additional information, 21 July 2008.
Note: Totals may not add up due to rounding.

EnergyAustralia

EnergyAustralia proposed a capex allowance of $8659 million ($2008–09) for the next regulatory control period. Tables 9 and 10 set out EnergyAustralia's proposed capex by expenditure purpose for distribution and transmission.

Table 9: EnergyAustralia's distribution capex proposal ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
System assets						
Asset renewal/replacement	487.2	592.9	653.5	663.5	798.2	3195.3
Growth (demand related)	498.0	582.3	604.4	560.1	536.5	2781.4
Reliability and quality of service enhancement	52.5	78.0	133.3	68.4	34.8	367.0
Environmental, safety, statutory obligations	53.2	50.8	87.4	94.0	68.1	353.6
Other	33.9	27.2	35.4	21.5	22.9	140.9
Total system assets	1124.7	1331.2	1514.1	1407.6	1460.6	6838.1
Non–system assets						
Business support	76.7	46.1	34.5	35.9	29.8	223.1
IT systems	118.3	55.5	62.6	40.1	42.9	319.4
Total non–system assets	195.0	101.7	97.1	76.0	72.7	542.5
Total	1319.7	1432.8	1611.2	1483.6	1533.3	7380.6

Source: EnergyAustralia, RIN template 2.2.1.
Note: Totals may not add up due to rounding.

Table 10: EnergyAustralia's transmission capex proposal ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
System assets						
Augmentation	76.2	83.1	68.4	81.5	90.6	399.8
Replacement	143.5	46.0	116.8	152.5	74.6	533.4
Reliability	2.0	0.8	45.0	83.2	39.7	170.8
Compliance	14.7	26.1	22.5	18.6	14.6	96.5
Total system assets	236.3	156.0	252.7	335.9	219.5	1200.5
Non–system assets						
Business IT	10.9	6.6	4.9	5.1	4.2	31.7
Support the business	17.0	8.0	9.0	5.8	6.2	45.8
Other	0.0	0.0	0.0	0.0	0.0	0.0
Total non–system assets	27.9	14.5	13.9	10.9	10.4	77.5
Total	264.2	170.5	266.6	346.7	229.9	1278.0

Source: EnergyAustralia, RIN template 2.2.1
Note: Totals may not add up due to rounding.

Integral Energy

Integral Energy proposed a capex allowance totalling $2953 million ($2008–09) for the next regulatory control period. Table 11 outlines the annual profile of Integral Energy's capex proposal by category.

Table 11: Integral Energy's capex proposal by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Growth	215.2	288.3	288.1	294.9	259.8	1346.2
Asset renewal/replacement	138.8	152.8	151.0	155.4	186.5	784.4
Reliability and quality of service enhancement	14.3	14.2	14.4	14.7	14.9	72.6
Compliance obligations	131.1	112.2	83.3	52.5	23.9	402.9
Other (emergency spares)	1.8	1.8	1.8	2.5	2.5	10.5
Total system assets	501.1	569.4	538.6	519.9	487.6	2616.6
Non–system assets	72.8	72.1	71.8	62.6	56.7	336.1
Total	573.9	641.5	610.4	582.5	544.3	2952.7

Source: Integral Energy, *Regulatory proposal*, p. 10.
Note: Totals may not add up due to rounding.

AER conclusion

To assess the NSW DNSPs forecast capex proposals the AER reviewed:

- the NSW DNSPs' governance frameworks, capex policies and procedures
- the methods used to develop the capex proposals, including planning processes, demand forecasts and network planning criteria,
- the need for the projects proposed in the regulatory proposals and whether the scope, timing and costs are efficient
- the cost estimation processes employed by the NSW DNSPs
- the deliverability of the forecast capex programs.

Country Energy

The AER has considered Country Energy's proposed forecast capex allowance of $4008 million ($2008–2009) and, for the reasons set out in chapter 7 of this draft decision, considers that the proposed capital projects and programs reviewed are consistent with the capex objectives in the NER. However, the AER does not consider Country Energy's forecast capex allowance satisfies the capex criteria of the NER.

The AER considers that the expenditure associated with Country Energy's application of input cost escalators does not reflect a realistic expectation of the cost inputs required to achieve the capex objectives. The AER also considers that Country Energy's forecast IT expenditure is unjustifiably high in comparison to other DNSPs, based on benchmark analysis. Following its review of Country Energy's capex proposal the AER has made the following adjustments to the proposed allowance:

- $66 million (25 per cent) reduction to forecast IT expenditure
- $21 million reduction to non–system land and building expenditures to correct for apparent double counting
- $12 million reduction to reflect that certain works (work on relay settings and tap changers) should not be capitalised
- $46 million net increase to reflect the application of modified input cost escalators to system and non–system capex (including updated CPI data) as determined in appendix N.

After making the adjustments outlined above, the AER considers that a forecast capex allowance that reflects the efficient costs a prudent operator in the circumstances of Country Energy would require to achieve the capex objectives and capex criteria in the NER is $3955 million. The AER's conclusion on Country Energy's forecast capex is set out table 12.

Table 12: AER's conclusion on Country Energy's capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy proposed capex	752.0	779.0	806.0	822.0	849.5	4008.4
Adjustment for incorrect capitalisation of tap changer setting expenditure	–2.4	–2.4	–2.4	–2.4	–2.5	–12.1
Adjustment for 25 per cent efficiency for IT expenditure	–15.9	–12.2	–12.4	–12.5	–12.6	–65.6
Adjustment for non–system land and buildings	–7.4	–4.1	–3.3	–3.0	–3.1	–20.8
Adjustments to cost escalators (including updated CPI)	16.2	16.5	12.0	5.3	4.5	45.5
AER capex allowance	742.6	776.8	799.9	809.3	826.7	3955.4

Note: Totals may not add up due to rounding

EnergyAustralia

The AER has considered EnergyAustralia's proposed forecast capex allowance of $8659 million ($2008–09) and, for the reasons set out in chapter 7 of this draft decision, considers that the proposed capital projects and programs reviewed are not consistent with the capex objectives in the NER.

The AER considers that EnergyAustralia's inclusion of the 'black spot' reliability program in its forecast capex did not reflect the capex objectives of the NER and determined that it should be removed from EnergyAustralia's forecast capex.

The AER also considered that EnergyAustralia's proposed capex for the replacement of feeders 908 and 909 did not comply with transitional provisions in the NER. The replacement of these feeders was the subject of a contingent project decision published by the AER in July 2008 and EnergyAustralia's proposed capex was not consistent with that decision.

Further the AER does not consider EnergyAustralia's forecast capex allowance satisfies the capex criterion of the NER. The AER considers that the expenditure associated with EnergyAustralia's application of input cost escalators does not reflect a realistic expectation of the cost inputs required to achieve the capex objectives. Following its review of EnergyAustralia cost escalation model the AER has:

- removed the effect of EnergyAustralia's assumed six month lag in input prices for key equipment costs
- modified the input cost escalators to reflect those determined in appendix N
- removed the real cost escalation of expenditure on wood poles
- corrected errors in the cost escalation model.

After making the adjustments as outlined above, the AER considers that a forecast capex allowance that reflects the efficient costs a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives and capex criteria in the NER is $8435 million. The AER's conclusion on EnergyAustralia's forecast capex is set out in tables 13 and 14.

Table 13: AER's conclusion on EnergyAustralia's distribution capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total EnergyAustralia proposed capex	1319.7	1432.8	1611.2	1483.6	1533.3	7380.6
Adjustment for correction of errors	–15.2	–20.4	–24.6	–17.1	–22.8	–100.0
Adjustments to cost escalators	3.0	–1.6	–15.2	–25.5	–44.1	–83.5
Adjustment to substation cost estimates	–4.3	–5.9	–5.0	–4.3	–3.5	–23.0
Adjustment to 'black spot' reliability project	–3.2	–3.2	–3.2	–3.3	–3.3	–16.2
AER capex allowance	1300.0	1401.8	1563.1	1433.4	1459.6	7157.9

Table 14: AER's conclusion on EnergyAustralia's transmission capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total EnergyAustralia proposed capex	264.2	170.5	266.6	346.7	229.9	1278.0
Adjustment for correction of errors	11.1	12.4	6.2	5.9	8.8	44.4
Adjustments to cost escalators	–3.4	–1.2	–5.9	–9.7	–6.9	–27.0
Adjustment to substation cost estimates	–1.6	–1.7	–2.0	–3.2	–2.4	–10.9
Adjustment to replacement of feeders 908 & 909	–6.4	–1.2	–	–	–	–7.6
AER capex allowance	264.0	178.9	264.9	339.7	229.3	1276.8

Integral Energy

The AER has considered Integral Energy's proposed forecast capex allowance of $2953 million and, for the reasons set out in chapter 7 of this draft decision, considers that the proposed capital projects and programs reviewed are consistent with the capex objectives in the NER. However, the AER does not consider Integral Energy's forecast capex allowance satisfies the capex criterion of the NER. The AER does not consider Integral Energy's proposed replacement capex reflects the efficient costs required to achieve the capex objectives.

Further, the AER does not consider that the expenditure associated with Integral Energy's application of input cost escalators reflects a realistic expectation of the cost inputs required to achieve the capex objectives. Following its review of CEG's cost escalation methodology, the AER has modified the input cost escalators used by Integral Energy in its regulatory proposal to reflect:

- updated methods in real forecast steel, copper and aluminium prices
- updated source data, where appropriate.

After making the adjustments as outlined above, the AER considers that a forecast capex allowance that reflects the efficient costs a prudent operator in the circumstances of Integral Energy would require to achieve the capex objectives and capex criteria of the NER is $2914 million. The AER's conclusion on Integral Energy's capex is set out in table 15.

Table 15: AER's conclusion on Integral Energy's capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Integral Energy's proposal	573.9	641.5	610.4	582.5	544.3	2952.7
Adjustments arising from replacement capex	0.0	–2.1	–3.1	–4.4	–20.1	–29.8
Adjustments arising from real cost escalators[a]	–2.0	–1.4	–1.0	–2.5	–2.4	–9.3
AER's capex allowance	571.9	638.0	606.3	575.5	521.9	2913.7

Note: Totals may not add due to rounding.
(a) Includes impact of revised inflation on 2007–08 base capex.

Forecast operating expenditure

NSW DNSP proposals

The DNSPs submitted opex proposals for the next regulatory control period totalling $6.7 billion ($2008–09), which represents an increase of $1.9 billion or 40 per cent over that spent in the current regulatory control period. An overview of the DNSPs' opex forecasts is provided below. Further details of the opex proposals are provided at chapter 8, and appendices O, P and Q.

Country Energy

Country Energy's forecast opex for the next regulatory control period is $2160 million, which is $626 million (42 per cent) more than its expected opex in the current regulatory control period.

Table 16 sets out Country Energy's forecast opex by cost category and year for the next regulatory control period.

Table 16: Country Energy's forecast opex by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Network operating costs	17.7	17.7	17.9	18.2	18.5	89.9
Network maintenance costs						
Inspection	38.3	39.2	40.4	41.8	43.2	202.9
Pole replacement	2.2	2.3	2.3	2.4	2.5	11.8
Maintenance and repair	67.7	69.2	71.4	73.9	76.5	358.7
Vegetation management	105.1	108.0	112.3	117.3	122.7	565.3
Emergency response	48.0	48.2	48.8	49.7	50.1	245.3
Other network maintenance costs	83.8	85.6	88.3	91.4	94.6	443.8
Other costs						
Meter reading	19.2	19.6	20.3	21.0	21.7	101.8
Customer service	13.4	13.7	14.2	14.7	15.2	71.2
Advertising, marketing and promotions	4.8	4.9	5.1	5.3	5.4	25.5
Other operating costs	0.0	0.0	0.0	0.0	0.0	0.0
Total controllable opex	400.3	408.4	420.9	435.4	451.0	2116.0
Self insurance costs	3.9	3.9	3.9	3.9	3.9	19.5
Debt raising costs	3.8	4.4	4.8	5.3	5.9	24.2
Total opex	408.1	416.7	429.7	444.7	460.7	2159.8

Source: Country Energy, *Regulatory proposal*, p. 63.
Note: Totals may not add up due to rounding.

EnergyAustralia

EnergyAustralia's forecast opex for the next regulatory control period is $3047 million, which is $902 million (30 per cent) greater than its expected opex in the current regulatory period. Table 17 sets out EnergyAustralia's forecast opex by cost category and year for the next regulatory control period.

In response to a number of issues raised by Wilson Cook, EnergyAustralia undertook further analysis in relation to the relationship between capex and maintenance expenditure. As a result of this analysis, EnergyAustralia's forecast network maintenance expenditure was reduced by $19 million. EnergyAustralia also advised that it identified errors in its asset age profile information which further reduced its opex forecast by $4 million.The adjusted maintenance expenditure forecasts and the consequent updated opex forecasts for the next regulatory control period are provided in table 18.

Table 17: EnergyAustralia's forecast opex by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Network operating	182.7	189.1	190.8	196.1	198.6	957.3
Network maintenance	219.7	226.0	236.7	247.7	260.7	1190.9
Other expenditure	155.3	159.2	165.1	172.2	172.4	824.2
Total controllable opex[a]	557.8	574.3	592.6	616.0	631.7	2972.4
Total controllable opex less self insurance costs[b]	552.0	568.5	586.8	610.2	625.9	2943.3
Self insurance costs	5.8	5.8	5.8	5.8	5.8	29.1
Debt raising costs	7.5	8.7	9.9	11.2	12.5	49.7
Equity raising costs	–	–	16.2	16.2	16.2	48.5
Proposed total opex	565.2	583.0	618.6	643.4	660.6	3070.6

Source: EnergyAustralia, RIN.
Note: Totals may not add up due to rounding.
(a) Includes self insurance costs.
(b) To ensure comparability with the other DNSPs the AER has restated EnergyAustralia's forecast controllable opex with these self insurance costs removed.

Table 18: EnergyAustralia's updated forecast opex by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Network operating	182.7	189.1	190.8	196.1	198.6	957.3
Network maintenance	217.7	222.7	231.8	242.6	252.4	1167.3
Other expenditure	155.3	159.2	165.1	172.2	172.4	824.2
Total controllable opex[a]	555.8	571.1	587.6	610.9	623.4	2948.8
Total controllable opex less self insurance costs[b]	550.0	565.2	581.8	605.1	617.6	2919.7
Self insurance costs	5.8	5.8	5.8	5.8	5.8	29.1
Debt raising costs	7.5	8.7	9.9	11.2	12.5	49.7
Equity raising costs	–	–	16.2	16.2	16.2	48.5
Proposed total opex	563.3	579.9	613.7	638.3	652.1	3047.0

Source: EnergyAustralia, RIN; and Wilson Cook, volume 2, p. 56.
Note: Totals may not add up due to rounding.
(a) Includes self insurance costs.
(b) To ensure comparability with the other DNSPs the AER has restated EnergyAustralia's forecast controllable opex with these self insurance costs removed.

Integral Energy

Integral Energy's forecast opex for the next regulatory control period is $1477 million, $345 million more (23 per cent) than its expected opex in the current regulatory control period.

Table 19 sets out Integral Energy's forecast opex by cost category for the next regulatory control period.

Table 19: Integral Energy's forecast opex by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Operating and maintenance						
Inspection	16.1	16.2	16.4	16.9	17.4	83.0
Maintenance	102.4	102.9	106.2	108.1	110.5	530.1
Other operating	50.7	50.1	53.3	55.5	58.0	267.9
Corporate support	112.1	110.5	107.7	109.6	110.3	550.2
Total controllable opex	281.3	279.6	283.6	290.2	296.6	1431.3
Self insurance costs	3.2	3.2	3.3	3.3	3.3	16.3
Debt raising costs	3.5	3.8	4.2	4..6	5.0	21.1
Equity raising costs	–	–	–	4.1	4.0	8.2
Proposed total opex	287.9	286.7	291.1	302.2	308.9	1476.8

Source: Integral Energy, *Regulatory proposal*, p. 128.
Note: Totals may not add up due to rounding.

AER conclusion

To assess the NSW DNSPs forecast opex allowance, the AER:

- considered the NSW DNSPs' regulatory proposals and additional supporting information
- reviewed the NSW DNSPs' planning procedures, policies and forecasting methods and the respective DNSP's application of such procedures, policies and forecasting methods to forecast projects and programs
- considered technical advice from Wilson Cook as independent engineering consultants
- considered the opex program and forecast allowance in the context of the objectives and criteria of the NER.

Country Energy

The AER has considered Country Energy's forecast total opex of $2160 million ($2008–09), and for the reasons outlined in chapter 8 of this draft decision, is not satisfied that the total opex forecast proposed by Country Energy reasonably reflects the opex criteria in the NER. In drawing this conclusion the AER has had regard to the opex factors set out in the NER.

On the basis of its analysis of Country Energy's proposed opex forecast and the advice of Wilson Cook, the AER has applied a reduction of $185 million to Country Energy's proposed opex. This represents a reduction of around 8.6 per cent of Country Energy's proposed opex of $2160 million and results in a revised forecast opex allowance of $1975 million.

This revised estimate represents the AER's estimate of the total opex cost that a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives. The AER is satisfied that the revised forecast opex of $1975 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. The AER's conclusion on Country Energy's opex by category is set in table 20.

Table 20: AER's conclusion on Country Energy's total opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy's controllable opex forecast	400.3	408.4	420.9	435.4	451.0	2116.0
Self insurance costs	3.9	3.9	3.9	3.9	3.9	19.5
Debt raising costs	3.8	4.4	4.8	5.3	5.9	24.2
Country Energy's total opex	408.1	416.7	429.7	444.7	460.7	2159.8
AER's controllable opex	354.9	363.0	373.2	424.1	432.5	1947.7
Self insurance costs	3.0	3.0	3.0	3.0	3.0	15.0
Debt raising costs	2.0	2.3	2.5	2.8	3.0	12.5
AER's total opex	359.9	368.2	378.8	429.9	438.5	1975.2

Note: Totals may not add up due to rounding. The AER will update the opex model with the latest CPI data at a time closer to its final determination.

EnergyAustralia

The AER has considered EnergyAustralia's forecast opex of $3047 million ($2008–09), and for the reasons outlined in chapter 8 of this draft decision, is not satisfied that the total opex forecast proposed by EnergyAustralia reasonably reflects the opex criteria in the NER. In drawing this conclusion the AER has had regard to the opex factors set out in the NER.

On the basis of its analysis of EnergyAustralia's proposed opex forecast and the advice of Wilson Cook, the AER has applied a reduction of $410 million to

EnergyAustralia's proposed opex. This represents a reduction of around 13 per cent of EnergyAustralia's proposed opex of $3047 million and results in a revised forecast opex allowance of $2638 million.

This revised estimate represents the AER's estimate of the total opex cost that a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives. The AER is satisfied that the revised total forecast opex of $2638 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. The AER's conclusion on EnergyAustralia's opex by category, and allocated between distribution and transmission is set out in table 21.

Table 21: AER's conclusion on EnergyAustralia's total opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia's controllable opex forecast[a]	555.8	571.1	587.6	610.9	623.4	2948.8
EnergyAustralia's controllable opex forecast (less self insurance costs)[b]	550.0	565.2	581.8	605.1	617.6	2919.7
Self insurance costs	5.8	5.8	5.8	5.8	5.8	29.1
Debt raising costs	7.5	8.7	9.9	11.2	12.5	49.7
Equity raising costs	–	–	16.2	16.2	16.2	48.5
EnergyAustralia's total opex	563.3	579.9	613.7	638.3	652.1	3047.0
AER's controllable opex	490.2	502.8	518.5	535.1	545.3	2591.9
Self insurance costs	4.1	4.1	4.1	4.1	4.1	20.4
Debt raising costs	3.8	4.5	5.1	5.8	6.4	25.5
Equity raising costs	–	–	–	–	–	–
AER's total opex	498.1	511.4	527.6	544.9	555.8	2637.7
Distribution network opex	466.2	479.7	495.8	512.7	523.7	2478.0
Transmission network opex	31.9	31.7	31.8	32.2	32.0	159.7

Note: Totals may not add up due to rounding. The AER will update the opex model with the latest CPI data at a time closer to its final determination.

(a) Includes self insurance costs.

(b) To ensure comparability with the other DNSPs the AER has restated EnergyAustralia's forecast controllable opex with these self insurance costs removed.

Integral Energy

The AER has considered Integral Energy's forecast total opex of $1477 million ($2008–09), and for the reasons outlined in chapter 8 of this draft decision, is not satisfied that the total opex proposed by Integral Energy reasonably reflects the opex criteria of the NER. In drawing this conclusion the AER has had regard to the opex factors set out in the NER.

After considering the advice of Wilson Cook, and undertaking its own analysis of Integral Energy's proposed opex, the AER has applied a reduction of $17 million to Integral Energy's proposed opex. This represents a reduction of around 1.2 per cent of Integral Energy's proposed opex of $1477 million and results in a revised forecast opex allowance of $1460 million.

This revised estimate represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of Integral Energy would incur to achieve the opex objectives. The AER is satisfied that the revised total forecast opex of $1460 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. The AER's conclusion on Integral Energy's opex by category is set in table 22.

Table 22: AER's conclusion on Integral Energy's total opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Integral Energy's controllable opex forecast	281.3	279.6	283.6	290.2	296.6	1431.3
Self insurance costs	3.2	3.2	3.3	3.3	3.3	16.3
Debt raising costs	3.5	3.8	4.2	4.6	5.0	21.1
Equity raising costs	–	–	–	4.1	4.0	8.2
Integral Energy's total opex	287.9	286.7	291.1	302.2	308.9	1476.8
AER's controllable opex	281.3	283.9	287.9	292.1	295.0	1440.1
Self insurance costs	1.9	1.9	1.9	1.9	1.9	9.6
Debt raising costs	1.7	1.9	2.1	2.3	2.5	10.6
Equity raising costs	–	–	–	–	–	–
AER's total opex	285.0	287.7	291.9	296.3	299.4	1460.3

Note: Totals may not add up due to rounding. The AER will update the opex model with the latest CPI data at a time closer to its final determination.

Estimated corporate income tax

NSW DNSP proposals

Each of the NSW DNSPs proposed an allowance for tax calculated by the PTRM, which calculates a tax allowance in accordance with the methodology set out in the NER. It should be noted that the allowance for tax is an output of the PTRM rather than an input to be specified or proposed by the regulated business.

Each of the NSW DNSPs proposed an opening tax asset base derived in a manner consistent with the AER's preferred approach set out in its issues paper on the transition from pre–tax to post–tax. The NSW DNSPs' proposed tax asset bases for the commencement of the next regulatory control period (as at 1 July 2009) are below:

- Country Energy—$2685 million
- EnergyAustralia—$4962 million
- Integral Energy—$2459 million.

AER conclusion

The AER has assessed each of the inputs to the PTRM that are used to calculate the expected cost of corporate income tax in accordance with the NER. The AER considers that each of the NSW DNSPs' proposed tax remaining and tax standard lives are appropriate. The AER also considers each of the NSW DNSPs' proposed opening tax asset bases appropriate and reasonable. Using these inputs, the AER has used the PTRM to calculate the allowance for corporate income tax in accordance with the NER, as set out in table 23.

Table 23: AER's conclusion on corporate income tax allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	46.2	49.7	43.7	50.9	55.9	246.5
EnergyAustralia	39.2	71.1	81.8	94.4	100.2	386.7
Integral Energy	37.8	39.1	39.3	38.4	41.2	195.9

Depreciation

NSW DNSP proposals

The NSW DNSPs proposed to continue using the straight-line approach to calculating depreciation in the PTRM. The NSW DNSPs proposed the regulatory depreciation allowances set out in table 24.

Table 24: DNSPs' proposed regulatory depreciation allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	110.9	138.6	163.7	155.0	147.6	715.8
EnergyAustralia	76.6	103.7	128.1	153.4	147.5	609.3
Integral Energy	115.8	95.3	93.2	86.5	91.4	482.2

Source: Country Energy, *Regulatory proposal*, p. 188; EnergyAustralia, *Regulatory proposal*, p. 23; Integral Energy, *Regulatory proposal*, p. 160.

AER conclusion

The AER has assessed each of the proposed asset class life inputs to the PTRM that are used to calculate the regulatory depreciation allowance in accordance with the NER. As a result of required adjustments to the asset life inputs to the PTRM for each NSW DNSP, it considers that the NSW DNSPs' proposed depreciation schedules do not comply with the NER and therefore has not approved the schedules.

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER has determined the NSW DNSPs' regulatory depreciation allowances for the next regulatory control period in accordance with NER, as set out in table 25.

Table 25: AER's conclusion on regulatory depreciation allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	158.4	169.2	132.7	152.0	172.0	784.2
EnergyAustralia	75.6	102.3	126.2	151.2	145.1	600.3
Integral Energy	137.6	117.0	110.5	102.2	100.4	567.7

Cost of capital

NSW DNSP proposals

In estimating the WACC for their regulatory proposals, the NSW DNSPs have used the values for the WACC parameters set out in the NER. A nominal vanilla WACC of 9.76 per cent was proposed by each DNSP.

AER conclusion

For this draft decision, the AER has determined a nominal vanilla WACC for each of the NSW DNSPs as set out in table 26. Table 26 also outlines the WACC parameter values for this draft decision. The AER will update the nominal risk-free rate and debt risk premium, based on the agreed averaging period, and the expected inflation rate at a time closer to its final distribution determination.

Table 26: AER's conclusion on WACC parameters

Parameter	Country Energy	EnergyAustralia	Integral Energy
Risk–free rate (nominal)	5.34%	5.34%	5.34%
Risk–free rate (real)	2.72%	2.72%	2.72%
Expected inflation rate	2.55%	2.55%	2.55%
Debt risk premium	3.29%	3.29%	3.29%
Market risk premium	6.00%	6.00%	6.00%
Gearing	60%	60%	60%
Equity beta	1.00	1.00	1.00
Nominal pre–tax return on debt	8.63%	8.63%	8.63%
Nominal post–tax return on equity	11.34%	11.34%	11.34%
Nominal vanilla WACC	9.72%	9.72%	9.72%

Service target performance incentive scheme

NSW DNSP proposals

Country Energy

Country Energy supported the AER's decision to continue information collection and monitoring based on the AER's national distribution STPIS. Country Energy considered that this approach will continue to provide effective commercial incentives to maintain and improve service performance levels.

EnergyAustralia

EnergyAustralia stated that the data collection exercise applying to it for the next regulatory control period should include a minimum set of measures, that may be reviewed at a later date. EnergyAustralia submitted that the most appropriate measures are those that:

- will be common to all NSW DNSPs
- are applied using consistent definitions
- that will demonstrate sufficient data integrity.

EnergyAustralia submitted that the reliability measures contained within the current licence conditions satisfy these requirements, noting that these requirements promote greater granularity of reliability information at the feeder category and individual feeder levels.

EnergyAustralia proposed that the AER draw on the annual Network Performance Report submitted by EnergyAustralia to the NSW Department of Water and Energy, as the source for the data collection process. EnergyAustralia further submitted that the harmonisation of the data collection arrangements with jurisdictional reporting requirements is highly desirable.

EnergyAustralia proposed that any adjustments arising from the application of the transmission STPIS under chapter 6 of the NER currently applying to its transmission assets for the remainder of the current regulatory control period, should be reflected in the transmission portion of its maximum allowed revenue going forward.

Integral Energy

Integral Energy submitted that the data collection exercise may be appropriate to define the data requirements and parameters to be measured in a national distribution STPIS, however it expressed caution against using actual results of the process for the purposes of establishing STPIS targets and incentives for the 2014 regulatory control period.

Integral Energy submitted that it has this concern due to the absence of financial incentives in a paper-based trial that would otherwise need to be considered by Integral Energy in its decision making.

AER conclusion

In consultation with the NSW DNSPs, the AER has developed service performance data reporting requirements for the 2009–14 regulatory control. As foreshadowed in the AER's final decision on STPIS arrangements for the ACT and NSW determinations, the data reporting requirements have been aligned with the requirements of the national distribution STPIS, published on 26 June 2008.

In accordance with NER, the AER will collect and monitor the NSW DNSPs service performance data during the next regulatory control period. Revenue will not be placed at risk under the data collection process during this period.

Collection of data consistent with the national distribution STPIS is important to ensure that a reliable data series is available for setting robust performance targets once the national distribution STPIS is applied in 2014.

The AER acknowledges that the NSW DNSPs may need to adjust existing systems and, in some cases, implement additional systems and processes, to achieve full compliance with the AER's national distribution STPIS by 1 July 2014. Given this, it acknowledges that full compliance may not be realised before the commencement of the next regulatory control period. To ensure that the data collection process is effective in establishing a useable data set for future target setting, the AER expects the NSW DNSPs to implement measures to achieve full compliance with the national distribution STPIS as soon as practical, but no later than December 2009.

In implementing the data reporting requirements, the AER expects to accumulate a sufficient data series to allow the application of the national distribution STPIS to the NSW DNSPs from 1 July 2014. The application of the national distribution STPIS for the 2014–19 regulatory control period to the NSW DNSPs will be the subject of consultation under the framework and approach process, prior to the 2014–19 distribution determination.

Efficiency benefit sharing scheme

NSW DNSP proposals

None of the NSW DNSPs proposed an adjustment mechanism for actual demand growth at the end of the next regulatory control period when calculating carryover amounts.

The EBSS allows DNSPs to propose a range of additional cost categories to be excluded from the operation of the EBSS. The scheme requires that these cost categories must be proposed by a DNSP in their regulatory proposal for the next regulatory control period. Integral Energy proposed that TUOS charges be excluded from the EBSS. Neither Country Energy nor EnergyAustralia proposed any cost categories be excluded from the operation of the EBSS.

AER conclusion

The AER will apply the EBSS released in February 2008 to the NSW DNSPs for the next regulatory control period. Given that none of the NSW DNSPs proposed an ex post demand growth adjustment method, the AER will not adjust the EBSS for the consequences of changes in demand growth for the NSW DNSPs for the next regulatory control period.

The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- non–network alternatives.

These are in addition to the costs of pass through events which are directly excluded by the EBSS.

Demand management incentives

NSW DNSP proposals

Country Energy

Country Energy stated that it supports the AER's decision to continue the D–factor scheme in NSW. However it considers that the D–factor is not an effective means of cost recovery for large scale pilot programs that incorporate smart meters. Country Energy proposed that the potential deployment of 'intelligent network infrastructure' be nominated as a pass–through event in the AER's distribution determination for the next regulatory control period, to overcome the limitations of the D–factor in providing cost recovery for large scale smart meter pilots.

Country Energy stated that to date it has made only modest claims under the D–factor due to the limited compatibility between currently available technologies for non–network alternatives, and the specific nature of emerging network constraints in the Country Energy service area.

Country Energy also submitted that to date, available demand management options have been generally unable to provide a reliable, economic alternative to capital investment to addressing reliability issues. It stated that there are comparatively few large customers or embedded generators in Country Energy's network, which limits opportunities for large scale load reductions in locations subject to network constraints.

Country Energy stated its support for the implementation of the AER's DMIA for the next regulatory control period. However, it submitted that the $0.6 million per annum allowance for Country Energy proposed within the AER's DMIA is unlikely to cover the cost of undertaking 'intelligent network pilots and trials,' and thus it proposed that the DMIA be increased.

EnergyAustralia

EnergyAustralia stated that it supported the AER's intention to continue the D–factor over the next regulatory control period.

EnergyAustralia stated that it interprets clause 11.1 of the D–factor scheme to mean any regulatory control period, and hence allows the inclusion of estimates of forgone revenues resulting from a reduction in demand due to demand management initiatives implemented in the current regulatory control period to be included in the D–factor calculations in the next regulatory control period. EnergyAustralia stated that this is consistent with the intention and historic operation of the D–factor scheme.

EnergyAustralia stated that it will seek and submit independent experts' reports to demonstrate the reasonableness of any ongoing forgone revenue impacts associated with previous demand management initiatives. EnergyAustralia provided to the AER independent experts' reports on its D–factor calculation and applications to IPART for years 2004–05, 2005–06 and 2006–07.

EnergyAustralia stated that it supports the AER's proposed DMIA, however, maintains its preference for a more generous incentive scheme. EnergyAustralia proposed a number changes to the original DMIA.

EnergyAustralia also proposed that the AER apply an 'I–factor' to allow cost recovery of $5 million per annum for network based innovations that are not readily foreseeable or quantifiable at the beginning of the regulatory control period. EnergyAustralia proposed that the 'I–factor' would provide incentives for a DNSP to carry out broad–based network related demand management innovations, such as asset management and communications improvement. EnergyAustralia proposed that the 'I–factor' operate as an extension to the AER's DMIA.

Integral Energy

Integral Energy stated that it supports the AER's continuation of the D–factor scheme in NSW for the next regulatory control period.

Integral Energy stated the AER's introduction of the DMIA is a positive move to encourage demand management innovation, and that it intends to undertake innovative tariff and non–tariff based demand management programs during the next regulatory control period.

Integral Energy submitted that it seeks an increase in the annual allowance from $0.6 million per annum to $1 million per annum to support a higher level of innovative demand management activity for the benefit of consumers. Integral Energy submitted that the proposed increase in the allowance aligns its allowance with that of EnergyAustralia, and reflects Integral Energy's view that the relative sizes of the DNSPs should not reduce the amount of funding for demand management.

AER conclusion

The AER maintains its decision to apply the D–factor scheme to the NSW DNSPs over the next regulatory control period, in the form applied by IPART over the current regulatory control period. The AER rejects EnergyAustralia's claim that forgone revenues associated with demand management projects implemented in the current regulatory control period should be recovered in the next regulatory control period under the D–factor scheme.

The AER considered EnergyAustralia's proposed I–factor and the NSW DNSP's proposals to increase the DMIA. The AER considers that the incentives under the D–factor and DMIS are sufficient to meet the AER's objectives in applying a DMIS.

The AER's draft decision, subject to the agreement of Country Energy, EnergyAustralia and Integral Energy (as the affected DNSPs), is to amend the DMIA applied in its final decision on DMIS, released on 29 February 2008, by replacing it with the replacement DMIA.

Pass through arrangements

NSW DNSP proposals

Country Energy

Country Energy proposed that the following six events be included as nominated pass through events in the AER's distribution determination:

- new or additional market requirements (such as the mandatory rollout of interval meters and the consequent significant data handling costs)
- 'Intelligent network' investments
- events that potentially could be classified as self insurance events
- changes in risk assessment costs due to court cases and other legal obligations

- changes to obligations, structure and costs due to outcomes of the Retail Reform Project

- input cost variations.

EnergyAustralia

EnergyAustralia proposed that the following seven events be included as pass through events:

- force majeure event

- cost or demand variance event

- joint planning event

- separation event

- compliance event

- customer connection event

- dead zone event.

Integral Energy

Integral Energy proposed that the following 12 events be included as pass through events:

- an asbestos event

- an automated interval meters event

- a business continuity event

- a change in ownership event

- a change in reporting requirements event

- a distribution loss event

- an EMF event

- an emissions trading scheme event

- a functional change event

- a gradual pollution event

- a retailer of last resort event

- a sabotage event.

AER conclusion

The AER accepts a retail project event and force majeure event as nominated pass through events for the NSW DNSPs. For the reasons set out in chapter 15 of this draft decision the AER does not consider that the other proposed pass through events meet the AER's assessment criteria and therefore it does not accept those events as nominated pass through events. In some instances the AER considers that the proposed pass through events are likely to be regulatory change events and therefore separate nominated events are unnecessary. In other cases the AER considers that inclusion of the proposed pass through events may act to undermine the incentive feature of the regulatory framework.

Building block determinations

NSW DNSP proposals

Country Energy

Country Energy's calculation of annual revenue requirements and X factors is contained in the completed PTRM submitted as part of its regulatory proposal and are summarised in table 27.

Table 27: Country Energy's proposed annual revenue requirements and X factors ($m nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		110.9	138.6	163.7	155.0	147.6
Return on capital		413.2	479.4	547.6	619.0	696.1
Tax allowance		40.8	45.6	50.7	52.8	53.3
Operating expenditure		418.4	438.1	463.3	491.6	522.3
TUOS adjustment		–70.0	–	–	–	–
Annual revenue requirements		913.3	1101.7	1225.3	1318.4	1419.3
Expected revenues	753.2	963.9	1071.5	1191.2	1324.3	1420.2
Forecast CPI (%)		2.54	2.54	2.54	2.54	2.54
X factors[a] (%)		–23.14	–6.80	–6.80	–6.80	–3.00

Source: Country Energy, PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

EnergyAustralia

EnergyAustralia has modified the AER's PTRM to accommodate separate building block calculations under each form of control. This involves the separating of assets between its transmission and distribution services and allocating opex and non–system costs to these two groups of assets, in accordance with its cost allocation method. The resulting revenue requirements and X factors proposed for transmission and distribution services is summarised in tables 28 and 29. Table 30 illustrates the differences between tables 28 and 29.

Table 28: EnergyAustralia's proposed annual revenue requirements and X factors – transmission ($m nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		4.9	8.1	11.4	14.5	13.4
Return on capital		96.5	123.1	140.2	167.7	204.5
Tax allowance		3.1	7.1	8.5	10.1	11.6
Operating expenditure		39.0	40.2	43.6	45.5	47.0
Annual revenue requirements		143.5	178.5	203.7	237.8	276.4
Expected revenues	129.5	143.5	170.4	202.5	240.5	285.7
Forecast CPI (%)		2.54	2.54	2.54	2.54	2.54
X factors[a] (%)		–8.06	–15.85	–15.85	–15.85	–15.85

Source: EnergyAustralia, PTRM.
(a) Negative values for X indicate real revenue increases under the CPI–X formula.

Table 29: EnergyAustralia's proposed annual revenue requirements and X factors – distribution ($m nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		71.7	95.6	116.7	138.9	134.2
Return on capital		705.3	833.3	974.8	1135.5	1283.4
Tax allowance		40.0	68.8	79.1	91.2	96.8
Operating expenditure		540.6	572.8	623.4	665.8	701.6
Annual revenue requirements		1357.6	1570.5	1793.9	2031.4	2216.0
Expected revenues	1021.9	1357.6	1549.2	1771.3	2011.8	2292.9
Forecast CPI (%)		2.54	2.54	2.54	2.54	2.54
X factors[a] (%)		–29.42	–10.43	–10.43	–10.43	–10.43

Source: EnergyAustralia, PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

Integral Energy

Integral Energy's calculation of annual revenue requirements and X factors is contained in the completed PTRM submitted as part of its regulatory proposal and are summarised in table 30.

Table 30: Integral Energy's proposed annual revenue requirements and X factors ($m nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		115.8	95.3	93.2	86.5	91.4
Return on capital		374.2	421.4	479.2	535.6	591.1
Tax allowance		40.9	42.2	42.5	43.4	47.5
Operating expenditure		295.2	301.4	313.9	334.1	350.2
Annual revenue requirements		826.1	860.3	928.7	999.6	1080.2
Expected revenues	656.7	805.5	867.5	936.7	1006.3	1083.5
Forecast CPI (%)		2.54	2.54	2.54	2.54	2.54
X factors[a] (%)		–18.21	–3.50	–3.50	–3.50	–3.50

Source: Integral Energy, PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

AER conclusion

The AER has calculated each of the NSW DNSPs' revenue requirements and X factors based on its decisions regarding the building block components. These calculations are summarised in the following sections.

Country Energy

The AER's draft decision results in a total revenue requirement over the next regulatory control period of $5819 million as set out in table 31, compared to $5978 million proposed by Country Energy. The main reasons for this difference reflect:

- a $196 million reduction to opex
- a $68 million increase in the regulatory depreciation building block reflecting changes to standard life assumptions
- a $35 million reduction to the return on capital.

Table 31: AER's conclusion on Country Energy's revenue requirements and X factors ($m nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		158.4	169.2	132.7	152.0	172.0
Return on capital		412.7	473.4	538.2	611.0	685.2
Tax allowance		46.2	49.7	43.7	50.9	55.9
Operating expenditure		369.1	387.2	408.4	475.4	497.4
TUOS adjustment		–70.0	–	–	–	–
Annual revenue requirements		916.4	1,079.6	1,123.0	1,289.3	1,410.4
Expected revenues	753.2	938.8	1,043.3	1,159.6	1,288.9	1,382.2
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–19.71	–6.80	–6.80	–6.80	–3.00

Source: Country Energy, PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

EnergyAustralia

The AER's draft decision results in total revenue requirements over the forthcoming regulatory control period of $994 million for transmission and $8453 million for distribution, compared to $1040 million and $8969 million respectively proposed by EnergyAustralia. The overall difference in nominal revenue requirements mainly reflects:

- a $469 million (nominal) reduction to opex
- a $54 million (nominal) reduction to the return on capital.

Table 32: AER's conclusion on EnergyAustralia's revenue requirements and X factors – distribution ($m nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		70.8	94.1	114.6	136.3	131.0
Return on capital		699.9	828.6	966.4	1121.5	1263.5
Tax allowance		36.1	64.3	73.8	84.8	89.6
Operating expenditure		478.1	504.5	534.7	567.0	594.0
Annual revenue requirements		1284.8	1491.5	1689.4	1909.5	2078.2
Expected revenues	1023.7	1284.8	1469.5	1670.4	1886.6	2138.0
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–24.30	–10.43	–10.43	–10.43	–10.43

Source: EnergyAustralia, PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

Table 33: AER's conclusion on EnergyAustralia's revenue requirements and X factors – transmission ($m nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		4.8	8.1	11.6	14.9	14.0
Return on capital		95.7	122.6	140.6	167.8	203.6
Tax allowance		3.0	6.9	8.0	9.6	10.6
Operating expenditure		32.8	33.3	34.3	35.6	36.3
Annual revenue requirements		136.3	170.9	194.6	227.9	264.5
Expected revenues	129.5	137.1	162.9	193.5	229.9	273.1
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–3.26	–15.85	–15.85	–15.85	–15.85

Source: PTRM
(a) Negative values for X indicate real revenue increases under the CPI–X formula.

Integral Energy

The AER's draft decision results in a total revenue requirement over the next regulatory control period of $4632 million as set out in table 34, compared to $4695 million proposed by Integral Energy. The main reasons for this difference reflect:

- removal of the $170 million from Integral Energy's opening RAB

- reductions to capex and opex as a result of this draft decision,due to the application of revised real cost escalations.

Table 34: AER conclusion on Integral Energy's revenue requirements and X factors ($m nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		137.6	117.0	110.5	102.2	100.4
Return on capital		357.4	402.1	457.2	511.2	564.2
Tax allowance		37.8	39.1	39.3	38.4	41.2
Operating expenditure		292.2	302.6	314.8	327.7	339.5
Annual revenue requirements		825.0	860.8	921.8	979.5	1045.4
Expected revenues	661.5	792.8	856.0	925.0	996.8	1075.4
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–15.42	–3.50	–3.50	–3.50	–3.50

Source: Integral Energy, PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

Alternative control services

NSW DNSP proposals

The NSW DNSPs have each proposed a schedule of fixed prices for the first year and a proposed price path for the remaining years of the next regulatory control period. The NSW DNSPs stated that they are attempting to bring public lighting prices to a cost reflective position.

Integral Energy applied a limited building block approach in developing its schedule of prices. Country Energy and EnergyAustralia developed their schedule of prices based on cost to serve models that do not rely on a regulated asset base, forecast opex or forecast capex.

AER conclusion

The AER will require each NSW DNSP to develop two schedules of fixed prices for the first year of the next regulatory control period and a price path for the remaining regulatory years of the next regulatory control period. The first schedule of prices will relate to public lighting assets constructed before 1 July 2009 and the second schedule will relate to public lighting assets constructed after 30 June 2009. The schedules of prices must be developed in accordance with the approach set out in section 17.6.12. Following consideration of, and consultation on, the proposed schedules of prices and price paths, the AER will determine the schedule of fixed prices for each NSW DNSP for the first year of the next regulatory control period. For each remaining years of the next regulatory control period the prices in the schedules will be permitted to increase in accordance with a price path approved by the AER.

Pricing methodology for EnergyAustralia prescribed (transmission) standard control services

EnergyAustralia proposal

EnergyAustralia stated that its proposed pricing methodology is consistent with the NER.

EnergyAustralia's proposed pricing methodology outlines:

- the calculation of the AARR for each year of the regulatory control period
- a proposed methodology to determine whether assets fall into the prescribed transmission service categories
- the allocation of the AARR to the categories of prescribed transmission service
- the allocation of the ASRR for each category of prescribed transmission service to connection points
- the methodology for implementation of the priority ordering approach under the NER including two worked examples
- billing arrangements
- management of prudential requirements and prudent discounts for new or existing connections to the EnergyAustralia transmission network
- a description of how asset costs which are associated with prescribed entry services and prescribed exit services at a connection point, which may be attributable to multiple transmission network users will be allocated
- its proposed approach to monitoring and compliance of its approved pricing methodology.

In response to a request from the AER, EnergyAustralia resubmitted its proposed pricing methodology on 28 October 2008, to clarify components of it cost allocation methodology.

AER conclusion

The AER has assessed EnergyAustralia's revised pricing methodology against part J of the NER and the pricing methodology guidelines. Based on that assessment, the AER has decided to approve EnergyAustralia's proposed pricing methodology, as set out in appendix T.

1 Introduction

1.1 Background

Under the National Electricity Law (NEL) and the National Electricity Rules (NER), the Australian Energy Regulator (AER) is responsible for the economic regulation of certain electricity distribution services provided by distribution network service providers (DNSPs) in the National Electricity Market (NEM).

The Independent Pricing and Regulatory Tribunal (IPART) made the current regulatory determinations for Country Energy, EnergyAustralia and Integral Energy (the NSW DNSPs) for a five–year period from 1 July 2004 to 30 June 2009 (the current regulatory control period) under the National Electricity Code, which has been replaced by the NER. These DNSPs own and operate the electricity distribution networks in NSW.

The AER has made these draft decisions and determinations according to the relevant transitional provisions within chapter 11 of the the NER (the transitional chapter 6 rules). The AER's principal task is to set the building block revenues that the NSW DNSPs can recover from the provision of direct control services during the next regulatory control period (1 July 2009 to 30 June 2014).

Through its distribution determinations, the AER is required to provide the NSW DNSPs with the opportunity to recover sufficient revenues to meet the efficient costs of providing direct control services and complying with regulatory obligations.

On 2 June 2008 the NSW DNSPs submitted their regulatory proposals, and proposed negotiating frameworks for the next regulatory control period to the AER.[1] On 26 June 2008 the AER published these and its proposed negotiable component criteria for the NSW DNSPs and its negotiated distribution service criteria for EnergyAustralia.

1.1.1 National Electricity Law

The NEL sets out the functions and powers of the AER, including its role as the economic regulator of utilities operating in the NEM. Section 16 of the NEL states that when performing or exercising a regulatory function or power, the AER must do so in a manner that will or is likely to contribute to the achievement of the national electricity objective. The national electricity objective is:[2]

> …to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to
>
> (a) price, quality, reliability and security of supply of electricity; and
>
> (b) the reliability, safety and security of the national electricity system.

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1 Note, initially Country Energy did not submit a proposed negotiating framework with it regulatory proposal. However, following a request from the AER, Country Energy submitted a proposed negotiating framework on 14 November 2008.

2 NEL, section 7.

Further, the NEL specifies that in performing or exercising its regulatory functions or powers, the AER must ensure that the regulated distribution system operator to which the determination applies and any affected registered participant be:

- informed of material issues under the AER's consideration
- given a reasonable opportunity to make submissions in respect of that determination before it is made.

Section 16 of the NEL also specifies revenue and pricing principles that the AER must take into account in making a distribution determination in relation to direct control network services. These principles are:[3]

> (2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in–
>
> (a) providing direct control network services; and
>
> (b) complying with a regulatory obligation or requirement or making a regulatory payment.
>
> (3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes-
>
> (a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
>
> (b) the efficient provision of electricity network services; and
>
> (c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.
>
> (4) Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted-
>
> (a) in any previous-
>
> (i) as the case requires, distribution determination or transmission determination; or
>
> (ii) determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or
>
> (b) in the Rules.
>
> (5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.
>
> (6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.
>
> (7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system

[3] NEL, section 7A.

with which a regulated network service provider provides direct control network services.

1.1.2 National Electricity Rules

The transitional chapter 6 rules set out provisions the AER must apply in exercising its regulatory functions and powers for electricity distribution networks in the ACT and NSW for the next regulatory control period. In particular, the AER must make a distribution determination for each NSW DNSP that includes a:

- building block determination in respect of standard control services
- determination in respect of alternative control services
- determination relating to the negotiating framework for direct control services
- determination specifying the negotiable component criteria for direct control services.

The distribution determination for EnergyAustralia must also specify a:

- determination relating to the negotiating framework for negotiated distribution services
- determination specifying the negotiated distribution service criteria for negotiated distribution services
- decision on the proposed pricing methodology, in which the AER either approves or refuses to approve that methodology in relation to EnergyAustralia prescribed (transmission) standard control services.

Building block determination

Clause 6.3.2 of the transitional chapter 6 rules requires a building block determination specify for a regulatory control period the following matters:

- the DNSP's annual revenue requirement for each regulatory year of the regulatory control period
- appropriate methods for the indexation of the regulatory asset base
- how any applicable efficiency benefit sharing scheme, service target performance incentive scheme, or demand management incentive scheme are to apply to the DNSP
- the commencement and length of the regulatory control period
- any amounts, values or inputs on which the building block determination is based.

Negotiating framework determination

A negotiating framework applies to circumstances where a person seeks to vary the normal terms and conditions relating to the supply of negotiable components of direct control services and EnergyAustralia's negotiated distribution services. Clause 6.7.3, as pertains to EnergyAustralia, and clause 6.7A.3 of the transitional chapter 6 rules state that a determination relating to the negotiating framework of a DNSP must set out requirements that are to be complied with in respect of the preparation, replacement, application and operation of a DNSP's negotiating framework.

Clause 6.7.5 of the transitional chapter 6 rules, as pertains to EnergyAustralia, requires that a DNSP must prepare a negotiating framework setting out the procedure to be followed during negotiations between the DNSP and any person who wishes to receive a negotiated distribution service from the DNSP, as to the terms and conditions of access for the provision of the service.

Clause 6.7A.5 of the transitional chapter 6 rules requires that a DNSP must prepare a negotiating framework setting out the procedure to be followed during negotiations between the DNSP and any person who wishes to be provided with a negotiable component from the DNSP, as to the terms and conditions of access for the provision of a negotiable component.

Negotiable component criteria

The negotiable component criteria must give effect to and be consistent with the negotiable component principles set out in clause 6.7A.1 of the transitional chapter 6 rules.

Under clause 6.7A.4 of the transitional chapter 6 rules the AER's determination on the negotiable component criteria must set out the criteria that the DNSP must apply in negotiating:

- the terms and conditions of access including:
  - the variations to the prices that are to be charged for the provision of the negotiable component of the direct control service concerned by the DNSP for the relevant regulatory control period
  - any access charges which are negotiated by the DNSP during that regulatory control period.

The negotiable component criteria also must include criteria, which the AER will apply in resolving an access dispute between the DNSP and a person who wishes to be provided with a negotiable component, in relation to terms and conditions of access including:

- the variation of the prices that are to be charged for the provision of the negotiable component of the direct control service concerned by the DNSP
- any access charges that are to be paid to or by the DNSP.[4]

Negotiated distribution service criteria

Clause 6.7 of the transitional chapter 6 rules deals with negotiated distribution services and only applies to EnergyAustralia's negotiated distribution services. Under the chapter 6 transitional rules, a service provided by EnergyAustralia by means of, or in connection with, the EnergyAustralia transmission support network and which would otherwise be

[4] Transitional chapter 6 rules, clause 6.7A.4.

classified as a negotiated transmission service is deemed to be classified as a negotiated distribution service.

Under clause 6.12.1(16) of the transitional chapter 6 rules, the AER's distribution determination must set out the Negotiated Distribution Service Criteria (NDSC) for EnergyAustralia's negotiated distribution services. Further, the NDSC determined by the AER must give effect to, and be consistent with, the negotiated distribution service principles set out in clause 6.7.1 of the transitional chapter 6 rules.

The NDSC set out the criteria that are to be applied by EnergyAustralia in negotiating terms and conditions of access and any access charges for negotiated distribution services. The NDSC will also be used by the AER in resolving any dispute between EnergyAustralia and a person wishing to be provided with a negotiated distribution service.

1.2 Transitional arrangements

The timing of the changes to the NEL and NER, establishing a national framework for the economic regulation of distribution services, has required that transitional arrangements be included for the ACT and NSW DNSPs. The transitional arrangements have been established in the form of an appendix to chapter 11 of the NER specifying the form in which chapter 6 applies to NSW and the ACT for the next regulatory control period.

1.3 Review process

The AER has reviewed the NSW DNSPs' regulatory proposals and proposed negotiating frameworks in accordance with the review process outlined in Part E of the transitional chapter 6 rules. To date, this process has involved:

- Pre–consultation—the AER consulted with the NSW DNSPs about the development of the regulatory information notice, pro forma templates and guidelines.

- Cost allocation method—in March 2008 the AER assessed and approved cost allocation methods under clause 6.15.6 of the transitional chapter 6 rules.

- Proposal—the NSW DNSPs submitted their regulatory proposals and proposed negotiating frameworks to the AER on 2 June 2008. The AER assessed the NSW DNSPs' proposals against the transitional chapter 6 rules and the AER's transitional guidelines.

- Public consultation—the AER published the NSW DNSPs' regulatory proposals and the AER's proposed negotiable component criteria and proposed negotiated distribution service criteria on 27 June 2008 and called for interested parties to make submissions. The AER held a public forum on the NSW DNSPs' regulatory proposals on 30 July 2008, where each DNSP and interested parties made presentations.

- Submissions—the AER received 41 submissions on the NSW DNSPs' regulatory proposals and the AER's proposed negotiable component criteria and proposed negotiated distribution service criteria. The submission are listed in appendix U.

- Assessment by technical experts—the AER engaged Wilson Cook as a technical expert to advise it on a number of key aspects of the regulatory proposals.[5]

- Wilson Cook has provided its advice to the AER on these matters, representing its independent views based on its review. The AER has considered this advice in making its draft distribution determination. The terms of reference guiding Wilson Cook's review are set out in appendix A of volume 1 of its report.

- Assessment by demand forecast experts—the AER engaged McLennan Magasanik Associates (MMA) as a technical expert to advise in relation to demand forecasts.

- Additional technical advice—the AER engaged Energy and Management Services (EMS) to provide the AER with technical and engineering advice throughout the review process.[6] EMS assisted the AER in reviewing the technical aspects of material contained in the NSW DNSPs' proposals, submissions and Wilson Cook's report.

- Other specialist advice—the AER also engaged Econtech to provide a forecast of ACT and NSW labour costs relevant to electricity distribution businesses.[7]

1.4 Structure of draft decision

The AER's consideration of the NSW DNSPs' regulatory proposals and proposed negotiating frameworks together with the negotiable component criteria and the negotiated distribution service criteria to apply, are set out as follows:

- chapters 2 to 4 address the classification of services, arrangements for negotiation and control mechanisms for standard control services

- chapters 5 to 11 relate to key elements of the building block calculation

- chapters 12 to 15 set out relevant schemes and pass through arrangements

- chapter 16 sets out the annual building block revenue requirements for the next regulatory control period

- chapter 17 sets out the alternative control services control mechanism and the AER's review of alternative control services

- chapter 18 assesses EnergyAustralia's pricing methodology relating to their prescribed (transmission) standard control services.

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5 Wilson Cook & Co Limited is a group of engineering and business consultants with a primary focus on specialised needs and operations in electric power, gas and other allied sectors.

6 EMS is an engineering consulting firm.

7 Econtech Pty Ltd is an economic consulting firm that specialises in economic modelling, forecasting and policy analysis.

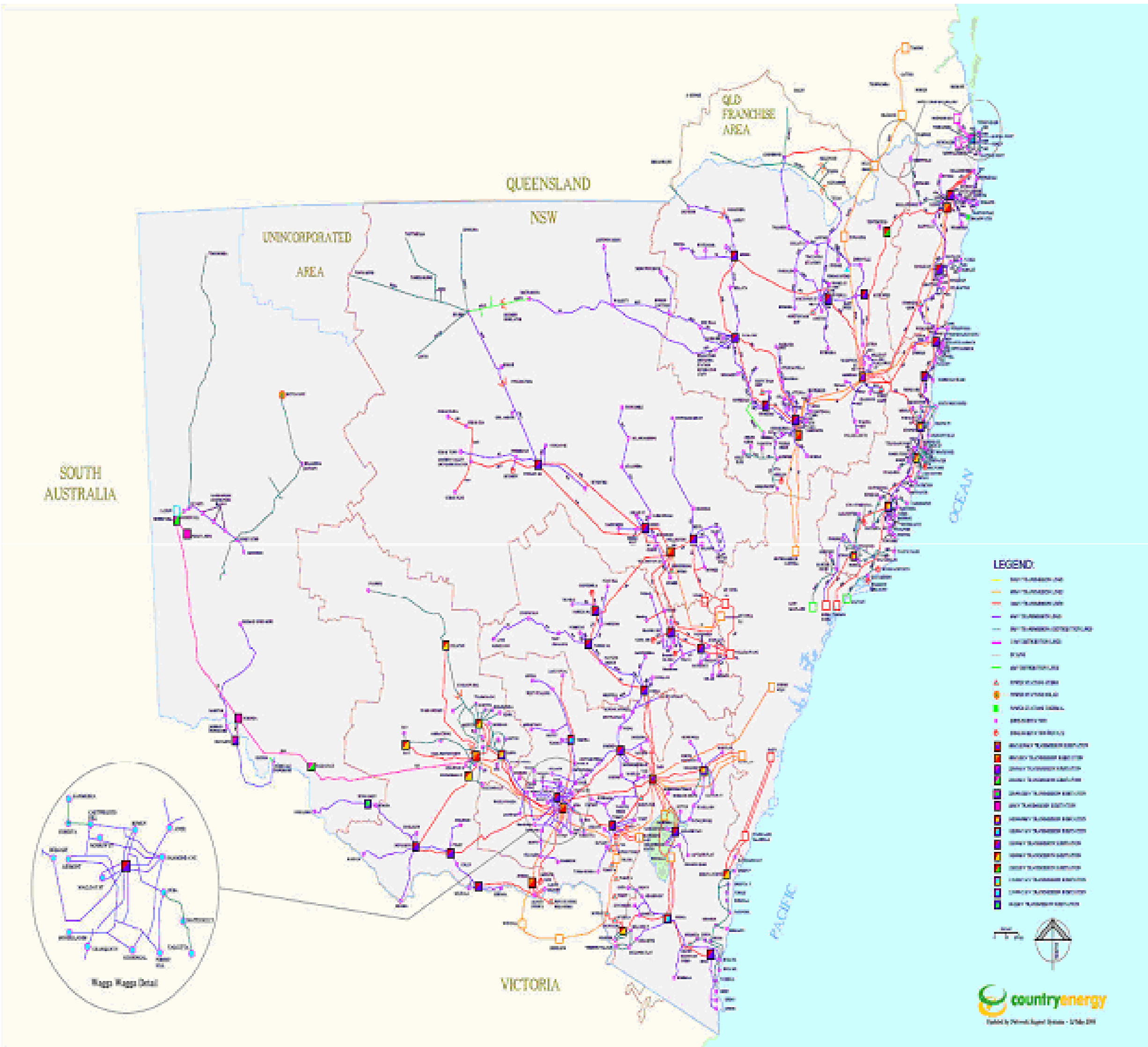
1.5 Overview of the NSW electricity distribution network

1.5.1 Country Energy's network

The Country Energy distribution network extends across approximately 95 per cent of the NSW land mass, as well as into parts of the Australian Capital Territory, Victoria and Queensland. The network consists largely of overhead assets including around 1.4 million poles, 200 000 km of powerlines, 330 zone substations and 130 000 distribution substations.[8]

The network currently services approximately 770 000 customers and delivers around 12 000 GWh of energy each year. Figure 1.1 shows Country Energy's network.[9]

Figure 1.1: Country Energy's distribution network



Source: Country Energy, *Regulatory proposal*, p. 24.

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[8] Country Energy, *Country Energy's electricity network regulatory proposal 2009–2014*, p. 22.
[9] Country Energy, *Regulatory proposal*, p. 22.

1.5.2 EnergyAustralia's network

EnergyAustralia owns, and operates an electricity distribution network in the Sydney, Central Coast and Hunter regions of NSW in a 22 275 square kilometres area.[10] EnergyAustralia's network also contains a small proportion of high voltage transmission assets within parts of the Sydney, Central Coast and Newcastle areas. Around 12 per cent of its network is classified as transmission assets, and are operated in parallel and in support of the TransGrid transmission network.

EnergyAustralia operates 903.3 circuit km of transmission lines and cables with nominal voltages of 132 kV and 66 kV. Its transmission network largely comprises of underground cables and overhead feeders, with associated exit assets, in the Sydney metropolitan area. It serves over 1.5 million customers.[11] Figure 1.2 shows the area covered by EnergyAustralia's distribution network.

Figure 1.2: EnergyAustralia's distribution network

Source: www.energyaustralia.com.au

10 www.energyaustralia.com.au
11 www.energyaustralia.com.au.

1.5.3 Integral Energy's network

Integral Energy provides distribution network services to almost 850,000 customers, or 2.1 million people, in households and businesses using its network of 24,500 square kilometres in Greater Western Sydney, the Blue Mountains, the Illawarra and the Southern Highlands.[12]

Integral Energy currently provides distribution network services to around 770,000 residential customers and 76,000 small business customers. There are also 3,700 large customers, with annual electricity consumption in excess of 160 MWh per annum, located within the Integral Energy network supply area.[13]

Figure 1.2: Integral Energy's distribution network

Source: Integral Energy, *Regulatory proposal*, p. 29.

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12 Integral Energy, *Regulatory proposal to the AER 2009 to 2014*, p. 1.
13 Integral Energy, *Regulatory proposal*, p. 27.

2 Classification of services

2.1 Introduction

A distribution service is a service provided by means of or in connection with a distribution network, together with the connection assets, which is connected to another transmission or distribution system. There are three classes of distribution services—direct control services; negotiated distribution services and unregulated distribution services. Direct control services are categorised under clause 6.2.3A(b) of the transitional chapter 6 rules as either standard control services or alternative control services.

This chapter sets out the AER's proposed classification of the NSW DNSPs' distribution services for the next regulatory control period.

2.2 Regulatory requirements

Clause 6.2.3B of the transitional chapter 6 rules specifies the classification of services that the AER is to apply—based on IPART's classification that applies in the current regulatory control period.

Direct control services

Standard control services

For the NSW DNSPs, IPART's prescribed distribution services are deemed to be standard control services for the purposes of the next regulatory control period under clause 6.2.3B(a) of the transitional chapter 6 rules. Consequently, the following prescribed distribution services are deemed to be standard control services:

- distribution use of systems services
- private power line inspections
- customer installation inspections
- certain monopoly services
- certain miscellaneous services
- certain emergency recoverable works.

The AER may vary this classification by agreement with a relevant NSW DNSP as part of its distribution determination under clause 6.2.3B(i) of the transitional chapter 6 rules.

Alternative control services

IPART classified the construction and maintenance of public lighting infrastructure as an excluded distribution service. This excluded distribution service is deemed to be an alternative control service under clause 6.2.3B(b)(1) of the transitional chapter 6 rules. Any other of IPART's excluded distribution services are deemed to be unregulated distribution services, unless the subject of an AER determination under clause 6.2.3B(b).

The AER may however vary any of these deemed classifications by agreement with the relevant NSW DNSP as part of its distribution determination under clause 6.2.3B(i) of the transitional chapter 6 rules.

Negotiated distribution services

Chapter 10 of the NER provides that a negotiated distribution service is a distribution service that is a negotiated network service within the meaning of section 2C of the NEL. Negotiated network service is defined in the NEL as follows:

> A negotiated network service is an electricity network service-
>
> (a) that is not a direct control network service; and
>
> (b) that-
>
> (i) the Rules specify as a negotiated network service; or
>
> (ii) if the Rules do not do so, the AER specifies as a negotiated network service in a distribution determination or transmission determination.[14]

Clause 6.2.3B of the transitional chapter 6 rules does not include any deeming of distribution services as negotiated distribution services. Further, clause 6.2.3B(i) only allows the AER to vary the deemed classification of services affected by clause 6.2.3B with the agreement of the relevant DNSP.

Clause 6.1.6(d) of the transitional chapter 6 rules provides that a service provided by EnergyAustralia by means of, or in connection with, the EnergyAustralia transmission support network and which would otherwise be classified as a negotiated transmission service is deemed to be classified as a negotiated distribution service.

Unregulated distribution services

For NSW DNSPs, clause 6.2.3B(b)(2)(i) of the transitional chapter 6 rules deems IPART's excluded distribution services (other than public lighting) to be unregulated distribution services. Unregulated distribution services include customer funded connections; customer specific services; and type 1-4 metering services.

Unregulated distribution services are subject to IPART's Regulation of Excluded Distribution Services Rule 2004/1 (Excluded Distribution Services Rule). Under clause 6.2.3B(c), a NSW DNSP is, in relation to an unregulated distribution service, required to comply substantially with the relevant requirements of the Excluded Distribution Services Rule. For the purposes of the transitional chapter 6 rules, the Excluded Distribution Services Rule applies as if references to IPART were references to the AER with any other necessary modifications.[15] Clauses 2.1(a)(2) and (c) of the Excluded Distribution Services Rule provides that there will be no form of regulation applying to excluded distribution services which IPART determines under clause 2.4(c) have satisfied the competition test. The competition test requires regard to be had to the structural features of the market such as: the number of firms and degree of market concentration, barriers to

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14 NEL, section 2C.

15 Transitional chapter 6 rules, clause 6.2.3B(d).

entry and exit, potential competition, supplier behaviour and customer outcomes.[16] However, clause 2.4(a) of the Excluded Services Rule provides that at any time during the current regulatory control period a DNSP may apply to IPART for a determination that any of its excluded distribution services (other than construction or maintenance of public lighting infrastructure) satisfy the competition test. The obligation to apply this test is not on the AER since the obligation only exits during the current regulatory period and the AER is not the relevant regulator under the Excluded Services Rule during that period.

Where the AER is not satisfied that a NSW DNSP, in relation to an unregulated distribution service substantially complies with the Excluded Distribution Services Rule, then it may reclassify the service to be an alternative control service under clause 6.2.3B(b)(2) of the transitional chapter 6 rules.

Unclassified services

The transitional chapter 6 rules contemplate that certain distribution services may be unclassified.[17] Unclassified services are not regulated by the AER under the transitional chapter 6 rules or the Excluded Distribution Services Rule.

2.2.1 Assigning customers to tariff classes

Under clause 6.12.1(17) of the transitional chapter 6 rules the AER must make a decision on the procedures for assigning and re-assigning customers to tariff classes for direct control services.

A DNSP is required to set out tariff classes as part of its pricing proposal that is submitted after the publication of the distribution determination under clause 6.18.1 of the transitional chapter 6 rules. Clause 6.18.3 provides that separate tariff classes are constituted for customers who are supplied with standard control services and alternative control services with regard to the need to group customers together on an economically efficient basis and the need to avoid unnecessary transaction costs.

Clause 6.18.4 of the transitional chapter 6 rules outlines the principles that the AER must have regard to when formulating procedures for the assignment or re-assignment of customers to tariff classes. These are:

> (a) …
>
> (1) customers should be assigned to tariff classes on the basis of one or more of the following factors:
>
> (i) the nature and extent of their usage
>
> (ii) the nature of their connection to the network
>
> (iii) whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement
>
> (2) customers with a similar connection and usage profile should be treated on an equal basis;

16 IPART, *Final Report: NSW Electricity Distribution Pricing, 2. Regulation of Excluded Distribution Services Rule 2004*, June 2004, Appendix 2, p. 106.

17 Transitional chapter 6 rules, see note to clause 6.2.3B(c).

(3) however, customers with micro–generation facilities should be treated no less favourably than customers without such facilities but with a similar load profile;

(4) a Distribution Network Service Provider's decision to assign a customer to a particular tariff class, or to re–assign a customer from one tariff class to another should be subject to an effective system of assessment and review.[18]

2.3 NSW DNSP proposals

EnergyAustralia is the only NSW DNSP proposing to reclassify its distribution services under clause 6.2.3B(i) of the transitional chapter 6 rules. EnergyAustralia has proposed reclassification of the following unregulated distribution services (currently subject to IPART's Excluded Distribution Services Rule) to unclassified services:[19]

1. metering services (types 1–4)

2. customer funded connections

3. customer specific services.

EnergyAustralia has also proposed that emergency recoverable works be reclassified from a standard control service (prescribed distribution service) to an unclassified service.[20]

In relation to metering services (types 1-4) and customer funded connections, EnergyAustralia's rationale is that such services are contestable.[21]

It argued that customer specific services and emergency recoverable works are not a distribution service and should not be regulated.

A summary of EnergyAustralia's proposal in relation to each of these proposed changes is set out below.

EnergyAustralia—metering services

EnergyAustralia submitted that a strong market already exists for metering services (types 1-4) as there are six metering providers who actively contest metering provision across the NEM and there has been no evidence of dominance by a particular provider, nor any evidence of collusion to establish dominance. EnergyAustralia believed the six providers of metering services have approximately equal market shares. EnergyAustralia submitted that a robust market exists in the provision of types 1-4 meters and that any regulation applied to EnergyAustralia's metering business is unnecessary and would potentially act to disadvantage one participant in the market.[22]

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18 Transitional chapter 6 rules, clause 6.18.4.
19 EnergyAustralia, *Regulatory proposal*, pp. 172–174.
20 EnergyAustralia, *Regulatory proposal*, p. 176.
21 EnergyAustralia, *Regulatory proposal*, p. 173.
22 EnergyAustralia, *Regulatory proposal*, p. 173.

EnergyAustralia—customer funded connections

EnergyAustralia submitted that customer funded connections include design and construction of generator funded or customer funded connection works, and design and construction of generator funded or customer funded network augmentations.[23]

EnergyAustralia stated that customer funded connections are carried out by accredited service providers (ASPs). The construction of connection assets has been a contestable activity in NSW since 1998 and the proportion of work carried out by the ASPs has progressively increased in recent years. EnergyAustralia claimed that 75 percent of the connection assets that it receives are assets designed and constructed by ASPs on behalf of customers (under contestable arrangements). The remainder are constructed on a competitive basis by EnergyAustralia's construction arm.[24]

EnergyAustralia submitted that a robust market exists in the design and construction of connections and that the regulation of EnergyAustralia's contestable construction activities is both unnecessary and potentially damaging.[25]

EnergyAustralia noted that once constructed the asset forms part of the standard control service and part K of the transitional chapter 6 rules applies. Any elements of design of connection works required by EnergyAustralia to best satisfy the connection to the shared network which may be negotiated with the customer would fall under the negotiable components of a standard control service.[26]

EnergyAustralia—customer specific services

EnergyAustralia submitted that customer specific services are essentially an optional service requested by a distribution customer and include asset relocation works and conversion to aerial bundled cable.[27]

EnergyAustralia submitted that neither asset relocation works, nor conversion to aerial bundled cable works undertaken at the request of a third party (network user or some other person) are distribution services as defined under the NER.[28] This is because in EnergyAustralia's view:

- asset relocation works and conversation to aerial bundled cable are not services provided 'by means of' a distribution system. EnergyAustralia states that the wording is similar to the wording in Part IIIA of the *Trade Practices Act 1974*, which refers to a service provided 'by means of a facility'. Moving or changing the facility itself (other than, for example to accommodate a connection) would not fall within this definition[29]

- 'in connection with' a distribution system implies more than that the service is about or somehow related to the distribution system. EnergyAustralia provides the example

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23 EnergyAustralia*, Regulatory proposal*, p. 172.
24 EnergyAustralia*, Regulatory proposal*, p. 173.
25 EnergyAustralia*, Regulatory proposal*, p. 173.
26 EnergyAustralia*, Regulatory proposal,* p. 173.
27 EnergyAustralia*, Regulatory proposal,* p. 174.
28 EnergyAustralia*, Regulatory proposal,* p. 174.
29 EnergyAustralia*, Regulatory proposal,* p. 175.

that if a person requested a DNSP to paint its poles pink, this would not be a service 'in connection with the distribution system' simply because the subject matter of the request concerns the distribution system[30]

- IPART's definition of customer specific services provided that the services are undertaken at the request of a 'distribution customer', which may have reflected IPART's view of its jurisdictional limitations. EnergyAustralia stated that the capacity in which the request is made is a strange distinction to make because a request (unrelated to the service received by the customer at its connection point) may be made by a landowner who is also a distribution customer or by a landowner who is not. In either case, the request is made by the person in their capacity as landowner and, if the relocation work is performed, the person who made the request is a 'customer' for the purpose of the relocation service.[31]

EnergyAustralia also stated that the access implications of something being a distribution service are a relevant factor in determining the intended meaning of distribution service. EnergyAustralia noted that, from a policy point of view, it is difficult to see why, for example, a DNSP should be required to move its assets that are lawfully placed on land simply because a person requests the DNSP to do so. EnergyAustralia claimed that the DNSP is in no more of a monopoly position in this regard than any other asset owner and, with any other asset owner, this would be a matter for commercial negotiations.[32]

EnergyAustralia proposed that asset relocation works and conversion to aerial bundled cable (made at the request of a person) are not distribution services at all and hence are not capable of regulation under the rules. In the alternative, EnergyAustralia proposed that if the AER considers that these services are distribution services, then such services are only distribution services if they are requested by a network user and only to the extent that they relate to or impact on the network services received by that person; and that such services when requested by a person other than a network user are not distribution services.[33]

EnergyAustralia—emergency recoverable works

EnergyAustralia submitted that emergency recoverable works is largely concerned with the costs of repair of damage caused by a third party to a DNSP's network.[34]

EnergyAustralia did not consider emergency recoverable works to be distribution services for the following reasons:

- emergency recoverable works is not a service for which a DNSP seeks 'charges' but rather it is about the calculation of 'damages', which is a very different concept

- there are existing common law principles entitling a DNSP to recover the reasonable costs of repair from a third party for damage caused intentionally, recklessly or negligently

30 EnergyAustralia, *Regulatory proposal,* p. 175.
31 EnergyAustralia, *Regulatory proposal,* p. 175.
32 EnergyAustralia, *Regulatory proposal,* p. 176.
33 EnergyAustralia, *Regulatory proposal*, p. 174.
34 EnergyAustralia, *Regulatory proposal*, Attachment 2.1, p. 4.

- there are differences between regulated charges and common law principles regarding the quantification of damages: the common law is concerned with the actual costs of the particular job in question whereas IPART's regulatory approach requiring fixed rates to be set effectively averages a DNSP's costs across different repair jobs

- in EnergyAustralia's view, rates sought to be imposed by a regulator are not binding on the courts

- DNSP's may experience overall under-recovery because in a situation where actual costs were below the regulated rates, a judicial decision may mean that the DNSP may only charge the lower amount (being actual costs); and in a situation where actual costs were above the regulated rates, the DNSP may still only charge the lower amount (being the regulated rates) rather than the actual costs

- in EnergyAustralia's view, if the NEL and NER had intended to confer on the AER the power to regulate amounts that DNSPs could recover in damages, very clear words would be required. EnergyAustralia does not see such words

- EnergyAustralia did not think that where a plaintiff repairs its assets when they are damaged by a defendant, the plaintiff is providing a service to the defendant

- as a matter of policy, a DNSP should be in no different a position from any other plaintiff whose assets are damaged by a third party. The DNSP is in no more of a monopoly position than any other asset owner.[35]

EnergyAustralia considered that emergency recoverable works are not distribution services, and are not capable of regulation under the rules. In the alternative, if the AER considers that emergency recoverable works are distribution services, EnergyAustralia proposed that the deemed classification which applies to those services be varied so the services are unclassified and not regulated under the rules.[36]

2.4 Submissions

The Public Interest Advocacy Centre (PIAC) noted that the DNSPs' proposals, if implemented, will significantly increase household electricity prices and therefore the basic cost of living.[37]

In relation to the classification of services, the PIAC was concerned about the pass through of maintenance costs for power poles on private land and their status under price regulation.[38]

PIAC also noted that in relation to power poles on private land, IPART determined in its 2004/05 to 2008/09 Electricity Distribution Pricing Final Report that '…it is appropriate that these services be considered non-distribution services'.[39]

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[35] EnergyAustralia*, Regulatory proposal*, Attachment 2.1, p. 4.
[36] EnergyAustralia*, Regulatory proposal*, pp. 175–176.
[37] PIAC, *Submission on NSW Distribution Network Service Providers 2009- 2014 Regulatory Proposals,* 6 August 2008, pp. 2–3.
[38] PIAC, p. 3.

The PIAC was concerned about the equity impact of the IPART determination and submits that incorrect assumptions underpinning the IPART determination have resulted in a sub-group of consumers being unfairly discriminated against.[40]

The PIAC requested the AER to further explore the legal status of how maintenance costs for power poles on private land are passed on to consumers and assess its position on this matter for the next regulatory control period.[41]

2.5 Issues and AER consideration

2.5.1 Classification of services

Country Energy and Integral Energy

Country Energy and Integral Energy did not propose to vary the deemed classifications of services as set out in clause 6.2.3B of the transitional chapter 6 rules. The AER will apply the deemed classification of services.

EnergyAustralia

The AER notes that there is a clear presumption in clause 6.2.3B of the transitional chapter 6 rules that certain services provided by the DNSPs are distribution services and that the DNSPs' distribution services are deemed to be classified in a certain way. While the transitional chapter 6 rules allow a deemed classification to be varied with the agreement of the DNSP (see clause 6.2.3B(i)), the AER considers there is a strong presumption that it will follow the deemed classifications unless a DNSP can satisfy the AER that a different classification is clearly more appropriate.

IPART in its final report on the NSW electricity distribution pricing for the current regulatory control period stated that the regulatory framework for excluded distribution services (which is set out in IPART's Excluded Distribution Services Rule):

> ... is not intended to promote or improve competition in these markets – rather it is intended to protect customers in markets where competition is not fully developed. However, the Tribunal has aimed to balance this protection role with the need to allow competition to develop or improve.[42]

Under IPART's Excluded Distribution Services Rule, a DNSP may apply to IPART during the current regulatory control period for a determination that the excluded distribution services satisfy the 'competition test'.[43] If IPART determines that the competition test is satisfied in respect of an excluded distribution service, no form of regulation will apply to those services.[44] The AER understands that EnergyAustralia has not applied to IPART for a determination that any of the excluded distribution services for which it is seeking reclassification (ie. metering services (types 1-4), customer funded connection and customer specific services) satisfy the competition test.

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39 IPART, *NSW Electricity Distribution Pricing 2004-05 to 2008/09 Final Report,* June 2004, p. 176.
40 PIAC, p. 3.
41 PIAC, p. 3.
42 IPART, *NSW Electricity Distribution Pricing Final Report*, section 16.5, p. 175.
43 IPART, *Regulation of excluded distribution services rule 2004*, clause 2.1(a)(2), p. 98.
44 IPART, *Regulation of excluded distribution services rule 2004*, clause 2.1(c) and Appendix 2: Competition Test.

If the AER determines under clause 6.2.3B(e) of the transitional chapter 6 rules that a DNSP is not, or has ceased to be, in substantial compliance with the relevant requirements of the Excluded Distribution Services Rule for an unregulated distribution service, the service may be classified as an alternative control service.[45] If the AER reclassifies the service, it cannot be classified again as an unregulated distribution service (unless it appears to the AER the determination is affected by a material error or deficiency of a kind referred to in clause 6.13(a)).[46] In the AER's view, this indicates a preference for greater, rather than less, regulation of such unregulated distribution services.

The AER is of the view that IPART's consideration on this matter in its determination is still relevant and, given that the transitional chapter 6 rules impose the deemed classifications, the AER sees no reason at this time to change the deemed classifications or to decide whether or not certain services are distribution services. In addition, the AER is mindful that the effect a decision to reclassify certain services may have on specific customer groups should be explicitly considered. Similarly the scope for competitive provision of the services needs to also be reviewed.

The AER is of the view that it would be more appropriate to consider any proposed change as part of the normal framework and approach paper process which applies to distribution determinations made under chapter 6 of the NER. One of the matters to be dealt with in the framework and approach paper is the AER's likely approach (together with its reasons) to the classification of distribution services. Considerations regarding the impact of changing classifications on specific customer groups and any evidence of competitive supply arrangements for services can be considered in that context. The AER was not required to undertake the framework and approach paper process under the transitional chapter 6 rules due to the truncated timelines which apply to the NSW distribution determinations for the next regulatory control period.

In addition to the truncated timelines, the AER does not consider EnergyAustralia has provided sufficient information to satisfy it that:

- customer specific services and emergency recoverable works are not distribution services
- a different classification for metering services (types 1-4), customer funded connection, customer specific services and emergency recoverable works is clearly more appropriate for the next regulatory control period.

The AER would be prepared to consider a fully developed and detailed analysis prepared by EnergyAustralia regarding its distribution services and their classification when the AER commences the framework and approach paper process in anticipation of the distribution determination for the 2014–2019 regulatory control period.

Therefore, for EnergyAustralia, the AER does not propose to vary the deemed classification of services as set out in clause 6.2.3B of the transitional chapter 6 rules.

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45 Transitional chapter 6 rules, clause 6.2.3B(b)(2)(ii).
46 Transitional chapter 6 rules, clause 6.2.3B(f).

PIAC

In relation to the PIAC's submission regarding the maintenance costs of power poles on private land, the AER notes that IPART considered the maintenance of electrical installations and private power lines to be non-distribution services and therefore not regulated by IPART.[47]

IPART found that:

- electrical installations refer to the equipment and wiring on or near a customer's premises which connect it to the distribution network
- private poles are electricity poles located on a customer's premises used to convey electricity to the customer's residence or are for use on their premises.

IPART found that these assets are owned by the customer and the customer is responsible under the *Electricity Supply Act 1995* (NSW) for any maintenance works required on those assets. Therefore, IPART concluded that the assets are not part of the distribution system and the DNSPs do not have any obligations to maintain them. IPART noted that if the DNSPs do provide maintenance services for such assets they must levy a separate charge which will not be regulated under IPART's distribution determination for the current regulatory control period[48] or the Excluded Distribution Services Rule.[49]

However, IPART noted that DNSPs have an obligation to inspect these assets and works under the *Electricity Supply (Safety and Network Management) Regulation 2002* (NSW) to ensure the safety of the surrounding network. IPART determined that such inspection functions are part of the DNSPs' core functions and are therefore classified as a prescribed distribution service.[50] This prescribed distribution service is deemed to be classified as a standard control service under clause 6.2.3B of the transitional chapter 6 rules. The AER notes that the *Electricity Supply (Safety and Network Management) Regulation 2002* (NSW) has since been repealed and replaced with *Electricity Supply (Safety and Network Management) Regulation 2008* (NSW) which the AER understands contains similar obligations.

The AER is aware of the potential issues surrounding IPART's determination that maintenance of electrical installations and private power lines is a non-distribution service while private power line inspections and customer installation inspections are deemed to be standard control services under the transitional chapter 6 rules. However, the AER has decided that it would be more appropriate to consider whether or not maintenance of power poles on private land is a distribution service as part of the normal framework and approach paper process which applies to distribution determinations made under chapter 6 of the NER. The AER decided not to vary the deemed classification of EnergyAustralia's distribution services due to the truncated timelines which apply to the NSW distribution determinations and because there was no requirement to undertake a framework and approach paper process. There is no deeming provision for the maintenance of power poles on private land and the AER is of the view that it is

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47 IPART, *NSW Electricity Distribution Pricing Final Report* , pp. 175–176.
48 IPART, *NSW Electricity Distribution Pricing Final Report*, pp. 175–176.
49 IPART, *NSW Electricity Distribution Pricing Final Report*, p. 176.
50 IPART, *NSW Electricity Distribution Pricing Final Report*, p. 176.

appropriate to be consistent with the previous regulatory approach and treat the service as a non-distribution service for the next regulatory control period. Unlike unregulated distribution services which can be reclassified and made subject to greater regulation the AER does not have the ability to impose greater regulation on services which IPART has decided are non-distribution services.

The AER will be interested in considering submissions on the matter when the AER commences the framework and approach paper process in anticipation of the distribution determination for the 2014–2019 regulatory control period.

2.5.2 Assigning customers to tariff classes

The AER notes clause 6.12.1(17) of the transitional chapter 6 rules requires it to make a decision on the procedures for assigning or re-assigning customers to tariff classes as part of its distribution determination. There is no requirement on DNSPs to propose such procedures and consequently the AER must develop the required procedures.

Clause 6.18.4 sets out the principles that the AER must have regard to in formulating procedures for the assignment or re-assignment of customers to tariff classes. The AER, having regard to the principles in clause 6.18.4, proposes the following procedures that the NSW DNSPs are required to follow when assigning or re–assigning customers to tariff classes:

Assignment of existing customers to tariff classes at the commencement of the next regulatory control period

1. Each customer who was a customer of the DNSP immediately prior to1 July 2009, and who continues to be a customer of the DNSP as at 1 July 2009, will be taken to be "assigned" to the tariff class that the DNSP was charging that customer immediately prior to 1 July 2009.

Assignment of new customers to a tariff class during the next regulatory control period

2. If, after 1 July 2009, the DNSP becomes aware that a person will become a customer of the DNSP, then the DNSP must determine the tariff class to which the new customer will be assigned.
3. In determining the tariff class to which a customer or potential customer will be assigned, or re-assigned, in accordance with section 2 or 5, the DNSP must take into account one or more of the following factors:
   - the nature and extent of the customer's usage
   - the nature of the customer's connection to the network
   - whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.
4. In addition to the requirements under section 3 the DNSP, when assigning a customer to a tariff class, must ensure the following:
   a. that customers with similar connection and usage profiles are treated equally

b. that customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities.

Re-assignment of existing customers to another existing tariff during the next regulatory control period

5. If a DNSP believes that an existing customer's load characteristics or connection characteristics (or both) have changed such that it is no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned or a customer no longer has the same or materially similar load or connection characteristics as other customers on the customer's existing tariff, then the DNSP may re-assign that customer to another tariff.

6. The DNSP must notify the customer concerned in writing of the tariff class to which the customer will be re-assigned, prior to the re-assignment occurring. The notice must include advice that the customer may request further information from the DNSP, may object to the proposed re-assignment and, if the customer objects to the proposed re-assignment and that objection is not resolved to the satisfaction of the customer, the customer or the DNSP may request the AER to decide which of the DNSP's tariff classes the customer should be assigned to.

7. If, in response to a notice issued in accordance with section 6, the relevant DNSP receives a request for further information from a customer, the relevant DNSP must provide such information. If any of the information requested by the customer is confidential then the relevant DNSP is not required to provide that information to the customer.

8. If, in response to a notice issued in accordance with section 6, a customer makes an objection to the relevant DNSP about the proposed re-assignment, the relevant DNSP must reconsider the proposed re-assignment, taking into consideration the factors in section 3 above, and notify the customer in writing of its decision and the reasons for that decision.

9. If the AER receives a request in accordance with section 6, then it must decide which of the relevant DNSP's tariff classes the customer should be assigned to, taking into account one or more of the following factors:

   - the nature and extent of the customer's usage
   - the nature of the customer's connection to the network
   - whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

10. As soon as practicable after being requested to do so by the AER, the relevant DNSP must provide to the AER a statement setting out which tariff class a particular customer or group of customers has been assigned to and the reasons for the DNSP's decision.

11. The AER must notify the customer and the relevant DNSP in writing of its decision and the date from which its decision should be applied.

12. If the AER does not give a written notice under section 11 within 30 business days of receiving the relevant request under section 6 or within such further period that

the AER may decide, then the AER is to be regarded as having decided that the customer giving the relevant request under section 6 should not be re-assigned.

13. The relevant DNSP must comply with a decision by the AER under section 9 and 11 in relation to a customer.

System of assessment and review of the basis on which a customer is charged

14. Where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage or load profile, the relevant DNSP must set out in its pricing proposal a method of how it will review and assess the basis on which a customer is charged.

15. If the AER considers that the method provided under section 14 does not provide for an effective system of assessment and review of the basis on which a customer is charged, the AER may request additional information or request that the relevant DNSP resubmit a revised method.

16. If the AER considers the method provided in accordance with section 14 is reasonable it will approve that method by notice in writing to the relevant DNSP.

2.5.3 AER conclusion

The AER will implement the deemed classification of services for Country Energy and Integral Energy as provided for in clause 6.2.3B of the transitional chapter 6 rules. The AER does not accept EnergyAustralia's proposal that customer specific services and emergency recoverable works are not distribution services. The AER does not accept EnergyAustralia's proposed reclassification of metering services (types 1–4), customer funded connections, customer specific services and emergency recoverable works. The AER will implement the deemed classification of services for EnergyAustralia as provided for in clause 6.2.3B of the transitional chapter 6 rules.

The AER's procedures for assigning and reassigning customers to tariff classes for the NSW DNSPs, based on the principles in clause 6.18.4 of the transitional chapter 6 rules, are set out in appendix A of this decision.

2.6 AER draft decision

In accordance with clause 6.12.1(1) of the transitional chapter 6 rules the AER decides that the following classification of services will apply to Country Energy for the next regulatory control period:

- a distribution service provided by Country Energy that was previously determined by IPART to be a prescribed distribution service (for the purposes of the current regulatory control period) is deemed to be classified as a direct control service and further classified as a standard control service

- a distribution service provided by Country Energy that was previously classified as an excluded distribution service by IPART, specifically the excluded distribution service of the construction and maintenance of public lighting infrastructure (for the purposes of the current regulatory control period) is deemed to be classified as a direct control service and further classified as an alternative control service

- a distribution service provided by Country Energy that was previously classified as an excluded distribution service by IPART, and is not the excluded distribution service of the construction and maintenance of public lighting infrastructure (for the purposes of the current regulatory control period) is deemed to be classified as an unregulated distribution service
- there are no services classified as negotiated distribution services
- other distribution services provided by Country Energy are unclassified and not regulated under the transitional chapter 6 rules.

In accordance with clause 6.12.1(1) of the transitional chapter 6 rules the AER decides that the following classification of services will apply to EnergyAustralia for the next regulatory control period:

- a distribution service provided by EnergyAustralia that was previously determined by IPART to be a prescribed distribution service (for the purposes of the current regulatory control period) is deemed to be classified as a direct control service and further classified as a standard control service
- a distribution service provided by EnergyAustralia that was previously classified as an excluded service by IPART, specifically the excluded distribution service of the construction and maintenance of public lighting infrastructure (for the purposes of the current regulatory control period) is deemed to be classified as a direct control service and further classified as an alternative control service
- a distribution service provided by EnergyAustralia that was previously classified as an excluded service by IPART, and is not the excluded distribution service of the construction and maintenance of public lighting infrastructure (for the purposes of the current regulatory control period) is deemed to be classified as an unregulated distribution service
- a service provided by means of, or in connection with, the EnergyAustralia transmission support network and that, but for clause 6.1.6(d) of the transitional chapter 6 rules, would be a negotiated transmission service is deemed to be classified as a negotiated distribution service
- other distribution services provided by EnergyAustralia are unclassified and not regulated under the transitional chapter 6 rules.

In accordance with clause 6.12.1(1) of the transitional chapter 6 rules the AER decides that the following classification of services will apply to Integral Energy for the next regulatory control period:

- a distribution service provided by Integral Energy that was previously determined by IPART to be a prescribed distribution service (for the purposes of the current regulatory control period) is deemed to be classified as a direct control service and further classified as a standard control service.

- a distribution service provided by Integral Energy that was previously classified as an excluded distribution service by IPART, specifically the excluded distribution service of the construction and maintenance of public lighting infrastructure (for the purposes of the current regulatory control period) is deemed to be classified as a direct control service and further classified as an alternative control service.

- a distribution service provided by Integral Energy that was previously classified as an excluded distribution service by IPART, and is not the excluded distribution service of the construction and maintenance of public lighting infrastructure (for the purposes of the current regulatory control period) is deemed to be classified as an unregulated distribution service.

- Integral Energy has no services classified as negotiated distribution services.

- other distribution services provided by Integral Energy are unclassified and not regulated under the transitional chapter 6 rules.

In accordance with clause 6.12.1(17) of the transitional chapter 6 rules the AER decides the proceduresto be applied by the NSW DNSPs for assigning customers to tariff classes or reassigning customers from one tariff class to another are specified in appendix A of the draft decision.

3 Arrangements for negotiation

3.1 Introduction

This chapter sets out the AER's draft decisions regarding the arrangements facilitating negotiation for certain distribution services for the next regulatory control period. It sets out the regulatory requirements, proposals, and AER's considerations and conclusions on:

- those services, or components of services, which are to be classified as negotiable components during the next regulatory control period
- the negotiable component criteria (NCC)
- EnergyAustralia's negotiated distribution service criteria (NDSC)
- the negotiating framework to apply to negotiable components and EnergyAustralia negotiated distribution services.

A negotiated distribution service for the purposes of the NER is defined as a distribution service that is a negotiated network service under section 2C of the NEL. Section 2C of the NEL provides that a negotiated network service is a service that is not a direct control service and that the NER specify as a negotiated network service or, if the NER do not do so, that the AER specifies as a negotiated network service in its distribution determination. Clause 6.1.6(d) of the transitional chapter 6 rules deems EnergyAustralia's negotiated transmission services to be classified as negotiated distribution services. Part D of the transitional chapter 6 rules applies to EnergyAustralia negotiated distribution services.

However, clause 6.2.7A of the transitional chapter 6 rules provides that the control mechanism for direct control services for ACT and NSW DNSPs may include negotiable components to be regulated under part DA of the transitional chapter 6 rules. Part DA is a transitional provision and only applies for the next regulatory control period for ACT and NSW DNSPs. Future classification of services will be governed by the AER's likely approach in its framework and approach paper which must be prepared in anticipation of each distribution determination under general chapter 6 of the NER.

3.2 Negotiable components

3.2.1 Regulatory requirements

The AER may include in its distribution determination a decision that one or more components of the provider's direct control services are negotiable components (clause 6.7A). The AER must make a decision on which, if any, components of direct control services are negotiable components as part of its distribution determination under clause 6.12.1(16A). Negotiable components are described in clause 6.7A(b) as:

> … a negotiable component may be a particular component of the direct control service or may relate to the terms or conditions on which a direct control service or a component of a direct control service is provided.

If the AER decides that one or more components of direct control services provided by a DNSP are negotiable components then the provisions set out in clause 6.7A.1–6.7A.6 of the transitional chapter 6 rules will have effect.[51] These provisions cover:

- principles relating to access to negotiable components
- determination of terms and conditions of access for negotiable components
- negotiating framework determination
- negotiable component criteria determination
- preparation of and requirements for negotiating framework
- confidential information.

3.2.2 NSW DNSP proposals

Country Energy

Country Energy submitted that it had no negotiable components of direct control services, and consequently did not initially provide a negotiating framework. However, following a request from the AER, Country Energy provided a negotiating framework.[52]

EnergyAustralia regulatory proposal

EnergyAustralia submitted a substantive proposal in relation to negotiated components of direct control services.

EnergyAustralia did not propose any negotiable components of direct control services as it considered that there is only limited scope for negotiation in relation to direct control services and that it is difficult to define in advance which components will be negotiable. However, EnergyAustralia proposed a definition with examples to assist in identifying negotiable components of direct control services, rather than specifically identifying negotiable components.[53]

EnergyAustralia suggested that a negotiable component of a direct control service should be any component (or a condition of the service) where some variability can be applied to the provision of the direct control service without interfering with or in any way compromising a DNSP's ability to comply with any regulatory obligation or requirement of the NER.[54]

EnergyAustralia identified the following potential negotiable components:[55]

- location of substation to support customer load

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51 Transitional chapter 6 rules, clause 6.7A(d).
52 Country Energy, *Negotiating framework for negotiable components*, 14 November 2008.
53 EnergyAustralia, *Regulatory proposal*, pp. 177–179.
54 EnergyAustralia, *Regulatory proposal*, p. 177.
55 EnergyAustralia, *Regulatory proposal*, p. 177.

- location of customer’s connection to network and point of entry to the premises and location of metering
- voltage level of customer’s connection
- assessment of customers’ load requirements
- availability of standby supply from the EnergyAustralia grid when on-site generation is unavailable
- capacity of customer’s connection before augmentation of other works will be required
- design planning criteria which exceeds the applicable security standard.

Integral Energy regulatory proposal

Integral Energy proposed that the following components be classified as negotiable components of direct control services under clause 6.8.2(7) of the transitional chapter 6 rules:[56]

- a direct control service that exceeds the network performance requirements which that direct control service is required to meet under any jurisdictional electricity legislation;
- a direct control service that, except to the extent of any prescribed requirements of jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or 5.1 of the NER;
- a direct control service that is a connection service provided to serve network users at a single distribution network connection point, other than connection services that are provided by one network service provider to another network service provider to connect their networks where neither provider is a market network service provider; or
- the terms and conditions in respect of which any of the above are provided.

3.2.3 Submissions

The AER called for submissions as part of its *Explanatory Statement and Issues Paper*.[57]

The AER received one submission from EnergyAustralia responding to the AER’s proposed NCC and NDSC.

EnergyAustralia questioned the utility of ‘theoretical concepts’ such as NCC, especially when applied to services that are uncertain in terms of precise nature, timing and

56 Intergral Energy, *Regulatory proposal*, appendix H, section 1.3.

57 AER, *Call for submissions: Proposed negotiable component criteria for ACT and NSW distribution network service providers; Proposed negotiated distribution service criteria for EnergyAustralia—Explanatory statement and issues paper,* Canberra, June 2008.

quantum.[58] It also disagreed with the transitional chapter 6 rules approach to treating its transmission business services that are the subject of negotiation as requiring 'the establishment of a new service and a fundamentally different regulatory framework'.[59] In relation to distribution, EnergyAustralia preferred a negotiating framework within the standard control service category rather than the creation of separate services. It also sought recognition in the NCC of the 'integrated nature of the negotiated component and the provision of the standard control service' given that negotiable components will most often be applicable to terms and conditions of connection arrangements.[60]

3.2.4 Issues and AER considerations

Clause 6.12.1(16A) of the transitional chapter 6 rules requires the AER to decide which, if any, components of direct control services are negotiable components.

In considering possible negotiable components provided by the NSW DNSPs, the AER has also considered EnergyAustralia's claim that it will often be difficult to define in advance which components of direct control services will be negotiable. The AER accepts that differing circumstances may mean that a service component could be treated as negotiable for one customer but not for others.

The AER also notes that none of the NSW DNSPs have identified any specific negotiable components of direct control services which they intend to provide during the next regulatory control period.

Given the difficulty of identifying specific negotiable components that are universally applicable the AER considers it is not appropriate to specify any particular components of direct control services as negotiable components. However, the AER considers that it is appropriate to define negotiable components of a direct control services in order that the NSW DNSPs and their customers have a means by which they can identify negotiable components on a case-by-case basis. The AER considers that this will provide flexibility by allowing negotiation to take place in relation to these types of services (which would not have otherwise occurred). It is envisaged that only sophisticated customers of the NSW DNSPs would seek to negotiate for services which would be considered to be negotiable components of direct control services. Such negotiations are only likely to occur in a small number of circumstances and only in relation to a small element of the total service. The AER would expect the definition of negotiable components of direct control services to cover requests made by customers for aesthetic reasons or convenience.[61]

In developing a definition for negotiable components of direct control services, the AER acknowledges that it is important that a negotiable component does not interfere with a DNSP's ability to comply with any regulatory obligation or requirement of the NER. It is also envisaged that if there are concerns regarding threats to reliability, safety or security

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58 EnergyAustralia, *Response to AER's request for submissions on AER proposed NCC and NDSC*, 8 August 2006, p. 1.

59 EnergyAustralia, *NCC and NDSC*, p. 2.

60 EnergyAustralia, *NCC and NDSC*, p. 2.

61 Examples of possible points of negotiation could include a customer seeking a variation to the location of a substation required to support the customer's load, the voltage level at which the connection is made and the provision of alternate supply connections.

for other network customers posed by a proposed negotiable component then those concerns will need to be clearly specified and fairly assessed and not just cited as a reason for not negotiating.

The AER is also mindful of the need to simplify the process as much as possible, and has decided to apply the same definition of negotiable components to all three NSW DNSPs as it has applied to ActewAGL. This definition is broadly consistent with the approaches proposed by EnergyAustralia and Integral Energy.

The AER notes that the transitional chapter 6 rules regarding negotiable components will cease at the end of the next regulatory control period, and at that time those services will either have to be reclassified as negotiated services or will remain as direct control services not subject to negotiation.

The AER also notes EnergyAustralia's concerns raised in its submission, however, recognises that the AER's determination must be made in accordance with the transitional chapter 6 rules which currently mandate a separate regime for negotiated services, that is, NCC and NDSC.

3.2.5 AER conclusion

The AER has decided not to specify any particular components of the NSW DNSPs' direct control services as negotiable components for the next regulatory control period. However, the AER has decided to define a negotiable component of a direct control service as any component of a direct control service (or the terms and conditions on which that direct control service or component are provided) where:

- the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation
- the direct control service, except to the extent of any prescribed requirements of jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or 5.1 of the NER or
- the direct control service is a connection service provided to serve network users at a single distribution network connection point, other than connection services that are provided by one network service provider to another network service provider to connect their networks where neither provider is a market network service provider.

Therefore, components that fall within the scope of the above definition, are negotiable components. This approach to defining a negotiable component of a direct control service is based on the definition proposed by Integral Energy in its regulatory proposal.[62] The AER considers that this definition is consistent with the examples of potential negotiable components provided by EnergyAustralia and provides an appropriate framework under which the NSW and ACT DNSPs can operate. This approach will apply to Country Energy even though it proposed not having any components of direct control services which are negotiable.

[62] Integral Energy, *Regulatory proposal*, Appendix H, section 1.3.

3.3 Negotiable component criteria

3.3.1 Regulatory requirements

The AER may, if relevant, make a decision on the NCC as part of its distribution determination under clause 6.12.1(16B). The NCC sets out the criteria that are to be applied by the DNSP in negotiating the terms and conditions of access for negotiable components, including variations to the prices that are to be charged for certain direct control services and any access charges which are negotiated by the provider during the regulatory control period.[63]

The NCC will also be used by the AER in resolving any access dispute, between a DNSP and a person wishing to be provided with a negotiable component of a direct control service, in relation to the terms and conditions of access including:

- the variation of the prices that are to be charged for the provision of the negotiable component of the direct control service and

- any access charges that are to be paid to or by the provider.[64]

3.3.2 AER proposed negotiable component criteria

The AER has developed its proposed NCC based on the principles set out in clause 6.7A.1 of the transitional chapter 6 rules and has developed criteria that give effect to and that are consistent with those principles in accordance with clauses 6.7A.4(b) of the transitional chapter 6 rules. The AER has also included an additional criterion that promotes the achievement of the national electricity objective (see criterion 1 of the proposed NCC).[65]

In accordance with clauses 6.9.3(a) and 6.9.3(b) of the transitional chapter 6 rules, the AER published its proposed NCC and an issues paper in June 2008.[66]

EnergyAustralia regulatory proposal

EnergyAustralia supported the AER adopting the negotiable component principles in clause 6.7A.1 as the appropriate criteria. EnergyAustralia noted the negotiated transmission service criteria determined in the AER's recent ElectraNet decision adopted the relevant principles from Chapter 6A as the criteria without any additional matters.[67]

Submissions

EnergyAustralia proposed amendments to the NCC

Criterion 1
EnergyAustralia sought the deletion of the national electricity market objective as it is 'unnecessary and creates ambiguity'.[68] In the event that the criterion is retained,

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63 Transitional chapter 6 rules, clause 6.7A.4(a)(1).
64 Transitional chapter 6 rules., clause 6.7A.4(a)(2).
65 AER, *Call for submissions NCC and NDSC*, p. 14.
66 AER, *Call for submissions NCC and NDSC*.
67 EnergyAustralia, *Regulatory proposal*, p. 215.
68 EnergyAustralia, *NCC and NDSC*, p. 2.

EnergyAustralia proposed that the heading should be renamed the 'national electricity objective' and that the obligation should be to *contribute to* the achievement of the objective rather than the *promotion of* the achievement of the objective.[69]

Criterion 2
EnergyAustralia proposed criterion 2 be amended in relation to the terms and conditions of access to include the deeming provision in clause 6.7A.1(10). The provision states that the price for a negotiable component is to be treated as being fair and reasonable if it complies with the principles in clause 6.7A.1(1) to (8) of the transitional chapter 6 rules.[70]

Criterion 5
EnergyAustralia also sought to expand criterion 5 of the NCC to include the capital contributions requirements applied in part K of the transitional chapter 6 rules, particularly clause 6.21.4 that allows the application of IPART guidelines in relation to capital contribution charges. EnergyAustralia suggested that the majority of negotiable components will be in respect of the connection and therefore the price will largely be subject to the capital contributions framework.[71]

3.3.3 Issues and AER considerations

Criterion 1
The AER notes EnergyAustralia's objection to the inclusion of this criterion. The AER also notes EnergyAustralia's submission that the negotiated transmission service criteria determined in the AER's ElectraNet decision adopted the relevant principles from chapter 6A of the NER without any additional matters. However, the criteria determined in the AER's ElectraNet decision contained the additional criterion that referred to the national electricity market objective.[72] The inclusion of this criterion is appropriate and has been incorporated into the AER's previous determinations for transmission network service providers (TNSPs). The AER accepts EnergyAustralia's minor edits to the heading of the criterion in recognition of the rule change from 'national electricity market objective' to 'national electricity objective'.

The AER does not accept EnergyAustralia's submission in relation to changing 'promotion of' to 'contribute to'. The source of this obligation is contained in section 7 of the NEL which states that the national electricity objective is to promote efficient investment in, and efficient operation and use of, electricity services. This wording is also consistent with the criterion applied in other determinations by the AER.

Criterion 2
The AER notes that the NCC are only meant to give effect to and be consistent with the principles set out in clause 6.7A.1 of the transitional chapter 6 rules.[73] The AER is required to follow the NER when applying the criteria and therefore it is not necessary to amend the NCC as suggested in EnergyAustralia's submission. The AER further

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69 EnergyAustralia, *NCC and NDSC*, p. 3.
70 EnergyAustralia, *NCC and NDSC*, p. 3.
71 EnergyAustralia, *NCC and NDSC*, p. 3.
72 AER, *ElectraNet transmission determination 2008–09 to 2012–13: Final decision*, 11 April 2008, p. 113, which adopts the approach in:
AER, *ElectraNet transmission determination 2008–09 to 2012–13: Draft decision*, 9 November 2007, chapter 10, pp. 225–226 and Appendix H.
73 Transitional chapter 6 rules, clause 6.7A.4(b).

emphasises the importance of consistency with the negotiated transmission service criteria adopted in its previous determinations for TNSPs.

Criterion 5
It is noted that criterion 5 does not apply if the terms and conditions of access for a negotiable component are so different as to warrant a determination of the price without regard to the criterion. For this reason, it is not necessary to expand the criterion in the manner proposed by EnergyAustralia as there is sufficient flexibility within this criterion.

3.3.4 AER conclusion

In light of EnergyAustralia's submission, the AER will change the heading of criterion 1 from 'national electricity market objective' to 'national electricity objective'. The AER does not accept the other changes proposed by EnergyAustralia.

The NCC for the NSW DNSPs is set out in appendix B.

3.4 EnergyAustralia negotiated distribution services

Clause 6.1.6(d) of the transitional chapter 6 rules sets out that a service provided by EnergyAustralia by means of, or in connection with, the EnergyAustralia transmission support network and which would otherwise be classified as a negotiated transmission service is deemed to be classified as a negotiated distribution service.

Currently, EnergyAustralia negotiated distribution services are the only services classified as negotiated distribution services under the transitional chapter 6 rules.[74] EnergyAustralia negotiated distribution services are regulated under part D of the transitional chapter 6 rules.[75]

EnergyAustralia proposal

EnergyAustralia has outlined its approach to classifying and differentiating EnergyAustralia negotiated distribution services from its other services.[76]

AER conclusion

EnergyAustralia's negotiated transmission services are the only services which are deemed to be negotiated distribution services in the transitional chapter 6 rules.[77]

3.5 EnergyAustralia negotiated distribution service criteria

The effect of rule 6.7 and clause 6.12.1(16) of the transitional chapter 6 is that the AER must decide on the NDSC for EnergyAustralia negotiated distribution services.

The NDSC sets out the criteria that are to be applied by EnergyAustralia in negotiating terms and conditions of access for its negotiated distribution services, including the prices

74 Transitional chapter 6 rules, clause 6.1.6(d).
75 Transitional chapter 6 rules, clause 6.7.
76 EnergyAustralia, *Regulatory proposal*, Part II, attachment 1.1.
77 Transitional chapter 6 rules, clause 6.1.6(d).

that are to be charged for the provision of negotiated distribution services or any access charges which are negotiated by the provider during the regulatory control period.[78]

The NDSC will also be used by the AER in resolving any access dispute about terms and conditions of access including:

- the price that is to be charged for the provision of the negotiated distribution service by the provider; or
- any access charges that are to be paid to or by the provider.[79]

In accordance with clause 6.9.3(a) and 6.9.3(b) of the transitional chapter 6 rules, the AER has published its proposed negotiated distribution services criteria and an issues paper for consultation.[80]

EnergyAustralia Proposal

EnergyAustralia supported the AER adopting the negotiated distribution service principles in clause 6.7.1 as the appropriate criteria. EnergyAustralia notes the negotiated transmission service criteria determined in the AER's recent ElectraNet decision adopted the relevant principles from chapter 6A as the criteria without any additional matters.[81]

Submissions

EnergyAustralia proposed amendments to the NDSC

Criterion 1
EnergyAustralia's sought the deletion of the national electricity market objective as it is 'unnecessary and creates ambiguity'.[82] In the event that the criterion is retained, EnergyAustralia proposed that the heading should be renamed the 'national electricity objective' and that the obligation should be to *contribute to* the achievement of the objective rather than the *promotion of* the achievement of the objective.[83]

Criterion 2
EnergyAustralia proposed to amend criteria 2 in relation to the terms and conditions of access to include the deeming provision in clause 6.7.1(9) that stated that the price for a negotiated distribution service is to be treated as being fair and reasonable if it complies with the principles in clause 6.7.1(1) to (7) of the transitional chapter 6 rules.[84]

AER conclusion

EnergyAustralia proposed amendments to the NDSC

Criterion 1
The AER notes its discussion in relation to criterion 1 in relation to the NCC under section 3.3.3. The AER accepts EnergyAustralia's minor edits to the heading of the

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78 Transitional chapter 6 rules, clause 6.7.4(a)(1).
79 Transitional chapter 6 rules, clause 6.7.4(a)(2).
80 AER, *Call for submissions: NCC and NDSC.*
81 EnergyAustralia, *Regulatory proposal*, p. 215.
82 EnergyAustralia, *NCC and NDSC*, p. 2.
83 EnergyAustralia, *NCC and NDSC*, p. 3.
84 EnergyAustralia, *NCC and NDSC*, p. 3.

criterion in recognition of the rule change from 'national electricity market objective' to 'national electricity objective'.

The AER does not accept EnergyAustralia's submission in relation to changing 'promotion of' to 'contribute to' as per the discussion in section 3.3.3.

Criterion 2
The AER notes that the NDSC are only meant to give effect to and be consistent with the principles set out in clause 6.7.1 of the transitional chapter 6 rules.[85] The AER is required to follow the NER when applying the criteria and therefore it is not necessary to amend the NDSC as suggested in EnergyAustralia's submission. The AER further emphasises the importance of consistency with the criteria adopted in its previous determinations.

The NDSC for EnergyAustralia is set out in appendix C.

3.6 Negotiating framework

3.6.1 Regulatory requirements

The AER must make a decision on any negotiating framework that is to apply as part of its distribution determination under clause 6.12.1(15). Under clause 6.12.3(g) of the transitional chapter 6 rules, the AER must approve a proposed negotiating framework if it is satisfied that it adequately complies with the requirements of part DA for negotiable components of direct control services or part D for EnergyAustralia negotiated distribution services.

In accordance with clause 6.8.2(c)(8) of the transitional chapter 6 rules, a DNSP must submit a negotiating framework if it proposes negotiable components of direct control services as part of its regulatory proposal. Clause 6.7A.5(b) requires that a DNSP's negotiating framework must comply with the applicable requirements of its distribution determination and the minimum requirements for a negotiating framework set out in clause 6.7A.5(c).

EnergyAustralia has the additional obligation under clause 6.8.2(c)(10) to submit as part of its regulatory proposal a proposed negotiating framework for its negotiated distribution services. Clause 6.7.5(b) requires that EnergyAustralia's negotiating framework must comply with the applicable requirements of its distribution determination and the minimum requirements for a negotiating framework set out in clause 6.7.5(c). However, clause 6.7A.5(f) contemplates that EnergyAustralia may prepare and submit a single negotiating framework that will apply to both its negotiable components and negotiated distribution services.

The AER will assess the DNSPs' proposed negotiating frameworks to ascertain whether they satisfy the following minimum requirements:[86]

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85 Transitional chapter 6 rules, clause 6.7.4(b).
86 Transitional chapter 6 rules, clause 6.7A.5(c) of the in relation to negotiable components of direct control services and clause 6.7.5(c) in relation to EnergyAustralia's negotiated distribution services. It is noted that the minimum requirements in these clauses are identical.

- that the DNSP and service applicant negotiate the terms and conditions of access to a negotiable component or an EnergyAustralia negotiated distribution service (as applicable) in good faith

- that both the DNSP and service applicant provide all commercial information that will allow effective negotiation; although this does not include confidential information provided by a third party and commercial information may be provided on the condition of non-disclosure without consent[87]

- that the DNSP:

  - identifies and informs a service applicant of the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the negotiable component or EnergyAustralia negotiated distribution service (as applicable)

  - demonstrates that the charges reflect those costs and/or the increase or decrease (as appropriate)

  - has appropriate arrangements for assessment and review of the charges and the basis on which they are made

- a reasonable time period for negotiation and a requirement for each party to use reasonable endeavours to adhere to the time period

- a process for dispute resolution that allows for all disputes in relation to terms and conditions of access for the provision of negotiable components or EnergyAustralia negotiated distribution services (as applicable) to be dealt with in accordance with part L of the transitional chapter 6 rules

- arrangements for the payment of a DNSP's reasonable direct expenses incurred in processing the application to provide the negotiable component or EnergyAustralia negotiated distribution service (as applicable)

- that the DNSP determine the potential impact on other network users of the provision of the negotiable component or EnergyAustralia negotiated distribution service (as applicable)

- that the DNSP must notify and consult with any affected network users to ensure that the provision of negotiable components or EnergyAustralia negotiated distribution service (as applicable) does not result in non-compliance with its other obligations

- that the DNSP publish the results of negotiations on its website.

The AER must set out the reasons for its decision to approve, or refuse to approve, a DNSP's proposed negotiating framework.[88] The AER's determination relating to a DNSP's negotiating framework must set out any requirements that are to be complied with in respect of the preparation, replacement, application or operation of the DNSP's

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87 Transitional chapter 6 rules, clauses 6.7A.6 and 6.7.6.
88 Transitional chapter 6 rules, clause 6.12.2(4).

negotiating framework.[89] If the AER's decision is to refuse to approve a DNSP's proposed negotiating framework in its final decision, it must include an amended negotiating framework in its final determination. Any amendments made by the AER must be based on the DNSP's proposed negotiating framework and amended only to the extent necessary to enable it to be approved in accordance with the transitional chapter 6 rules.[90]

3.6.2 NSW DNSP proposals

EnergyAustralia has submitted a proposed negotiating framework to cover both negotiable components of direct control services and its negotiated distribution services as contemplated by clause 6.7A.5(f) of the transitional chapter 6 rules.[91]

Integral Energy has submitted its proposed negotiating framework for negotiable components of direct control services.[92]

Country Energy has submitted its proposed negotiating framework for negotiable components of direct control services.[93]

All three proposed negotiating frameworks are substantially similar and have been assessed together where there are joint issues.

The proposed negotiating frameworks apply to the relevant DNSP and any service applicant who has made an application in writing. Any service applicant should apply and comply with the requirements of the negotiating framework.[94] The requirements of the negotiating framework are additional to any requirements of clauses 5.3, 5.4A and 5.5 and chapter 6 and chapter 6A of the NER and if any inconsistencies exist, the requirements of the NER prevail.[95] The negotiating framework also requires that both parties involved in the negotiating process should negotiate, in good faith, the terms and conditions of access for the negotiable component.[96]

The proposed negotiating framework contains clauses that allow the provision of commercial information to both parties to facilitate effective negotiation and also contains appropriate safeguards for confidential information and disclosure by consent.[97]

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89 Transitional chapter 6 rules, clauses 6.7A.3 and 6.7.3.

90 Transitional chapter 6 rules, clause 6.12.3(h).

91 EnergyAustralia, *Regulatory proposal*, p. 215 and Attachment 5.1.

92 Integral Energy, *Regulatory proposal*, Appendix H.

93 Country Energy, *Negotiating framework for negotiable components*, 14 November 2008.

94 Country Energy, *Negotiating framework*, clauses 3 and 5, pp. 3–6;
EnergyAustralia, *Regulatory proposal*, Attachment 5.1, clause 1, p. 4;
Integral Energy, *Regulatory proposal*, Appendix H, clause 1, p. 4.

95 Country Energy, *Negotiating framework*, clause 16.3(3), p. 10;
EnergyAustralia, *Regulatory proposal*, Attachment 5.1, clause 1, p. 4;
Integral Energy, *Regulatory proposal*, Appendix H, clause 1, p. 4.

96 Country Energy, *Negotiating framework*, clause 3.3, p. 3;
EnergyAustralia, *Regulatory proposal*, Attachment 5.1, clause 2, p. 4;
Integral Energy, *Regulatory proposal*, Appendix H, clause 2, p. 5.

97 Country Energy, *Negotiating framework*, clause 6.1(1), 6.2(1) and 10, pp. 5–6 and 8–9;
EnergyAustralia, *Regulatory proposal*, Attachment 5.1, clause 4–5, pp. 6–7;
Integral Energy, *Regulatory proposal*, Appendix H, clauses 4–6 , pp. 6–8.

The proposed negotiating frameworks also require the DNSPs to identify and inform service applicants of the reasonable costs of providing the negotiable component and to demonstrate how the charges reflect those costs, including any increases or decreases. It also provides appropriate arrangements for assessment and review of charges and the basis of the charges.[98]

The timeframes for commencing, progressing and finalising the negotiation are set out in the negotiating framework. The proposed timeframes can be modified with the agreement of both parties. The negotiating framework states that once an application is received from a service applicant both parties must use their reasonable endeavours to adhere to the proposed timeframes.[99]

In Integral Energy's proposed negotiating framework, the stated timeframes do not commence until the service applicant has paid the application fee. In addition, the timeframes can recommence if there is a material change in nature of the negotiable component sought.[100] The application fee is not specified in the negotiating framework although it states that the application fee will be deducted from the reasonable costs incurred by Integral Energy in processing the application for the negotiable component and must be no more than Integral Energy's reasonable estimates of its costs in dealing with the application.[101]

EnergyAustralia's and Integral Energy's proposed negotiating frameworks state that the providers may issue the service applicant with a notice setting out the reasonable costs incurred and requesting payment of amounts above the application fee. Within 20 business days, the service applicant is required to pay the provider any amount requested in the notice. Further, the provider may require the service applicant to enter into a binding agreement regarding the payment of ongoing costs.[102] Country Energy's negotiating framework states that it will advise the date by which the service applicant must pay the fees.[103]

The proposed negotiating frameworks also recognise the DNSPs' obligation to determine the potential impact on other network users and notify and consult with any affected network users to ensure that the provision of negotiable components does not result in

98 Country Energy, *Negotiating framework*, clause 6.1(2), p. 5;
EnergyAustralia, *Regulatory proposal*, Attachment 5.1, clauses 5.1, 5.2 and 6, pp. 6–7;
Integral Energy, *Regulatory proposal*, Appendix H, clauses 6.1 and 6.2, p. 8.

99 Country Energy, *Negotiating framework*, clause 9, pp. 7-8;
EnergyAustralia, *Regulatory proposal*, Attachment 5.1, clause 3, pp. 4–5;
Integral Energy, *Regulatory proposal*, Appendix H, clause 3, pp. 5–6.

100 Integral Energy, *Regulatory proposal*, Appendix H, clause 3.6, p. 6.

101 Integral Energy, *Regulatory proposal*, clause 3.6, p. 6.

102 Integral Energy, *Regulatory proposal*, clause 10;
EnergyAustralia, *Regulatory proposal*, Attachment 5.1, clause 10.

103 Country Energy, *Negotiating framework*, clause 5.2(1)(b), p. 5.

non-compliance with other obligations.[104] They also each refer to the relevant dispute resolution mechanisms[105] and the obligation to publish results on the DNSPs' website.[106]

3.6.3 Issues and AER considerations

The AER notes that in relation to negotiable components of direct control services, the NSW DNSPs' proposed negotiating frameworks contain the requirements set out in clause 6.7A.5(c) of the transitional chapter 6 rules. The AER also notes that in relation to negotiated distribution services, EnergyAustralia's proposed negotiating framework contains the requirements set out in clause 6.7.5(c).

The AER notes that the distribution determination must set out the requirements that are to be complied with in respect of the preparation, replacement, application or operation of a DNSP's negotiating framework.[107]

The AER considers that in relation to negotiable components of direct control services, the NSW DNSPs have prepared their proposed negotiating frameworks in accordance with the requirements of clause 6.7A.5 and that the proposed application or operation of each framework is also specified in accordance with clause 6.7A.5. In addition, the AER considers that in relation to negotiated distribution services, EnergyAustralia has prepared its proposed negotiating framework in accordance with clause 6.7.5 and the proposed application or operation of the framework is in accordance with that clause.

The transitional chapter 6 rules do not explicitly state how or when a DNSP should replace its negotiating framework. In absence of a specific rule, the AER considers that a DNSP's negotiating framework will apply for the duration of the regulatory control period to which the distribution determination relates.

3.6.4 AER conclusion

As required by clause 6.12.3(g) of the transitional chapter 6 rules, the AER approves the NSW DNSPs negotiating frameworks to apply for the next regulatory control period. Country Energy's, EnergyAustralia's and Integral Energy's negotiating frameworks are in appendices D, E and F respectively. The AER considers that the negotiating frameworks comply with part DA of the transitional chapter 6 rules and, in the case of EnergyAustralia's negotiating framework, part D of the transitional chapter 6 rules.

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[104] Country Energy, *Negotiating framework*, clauses 7.1 and 7.2, p. 7;
EnergyAustralia, *Regulatory proposal*, Attachment 5.1, clause 7, p. 7;
Integral Energy, *Regulatory proposal*, Appendix H, clause 7, p .8.

[105] Country Energy, *Negotiating framework*, clause 11, p. 9;
EnergyAustralia, *Regulatory proposal*, Attachment 5.1, clause 9, p. 8.;
Integral Energy, *Regulatory proposal*, Appendix H, clause 9, p. 9.

[106] Country Energy, *Negotiating framework*, clause 12, p. 9;
EnergyAustralia, *Regulatory proposal*, Attachment 5.1, clause 12, p. 9.
Integral Energy, *Regulatory proposal*, Appendix H, clause 3.7, p. 6.

[107] Transitional chapter 6 rules, clauses 6.7A.3 and 6.7.3.

3.7 AER draft decision

In accordance with clauses 6.12.1(15) and 6.7A.3 of the transitional chapter 6 rules the AER decides the negotiating framework in appendix D of the draft decision is to apply to Country Energy for the next regulatory control period. The preparation of the negotiating framework for 2014–2019 regulatory control period must be undertaken in accordance with the framework and approach processes for that regulatory control period.

In accordance with clause 6.12.1(16A) of the transitional chapter 6 rules the AER decides that the components of Country Energy's direct control services which are negotiable components are any component of a direct control service (or the terms and conditions on which that direct control service or component are provided) where:

- the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation;
- the direct control service, except to the extent of any prescribed requirements of jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or 5.1 of the NER; or
- the direct control service is a connection service provided to serve network users at a single distribution network connection point, other than connection services that are provided by one network service provider to another network service provider to connect their networks where neither provider is a market network service provider.

In accordance with clause 6.12.1(16B) and 6.7A.4(a) of the transitional chapter 6 rules the AER decides the NCC for Country Energy is at appendix B of the draft decision.

In accordance with clauses 6.12.1(15) and 6.7A.3 of the transitional chapter 6 rules the AER decides the negotiating framework in appendix E of the draft decision is to apply to EnergyAustralia for the next regulatory control period. The preparation of the negotiating framework for 2014–2019 regulatory control period must be undertaken in accordance with the framework and approach processes for that regulatory control period.

In accordance with clauses 6.12.1(16) and 6.7.4(a) of the transitional chapter 6 rules the AER decides that the negotiated distribution service criteria in appendix C of the draft decision is to apply to EnergyAustralia for the next regulatory control period.

In accordance with clause 6.12.1(16A) of the transitional chapter 6 rules the AER decides that the components of EnergyAustralia's direct control services which are negotiable components are any component of a direct control service (or the terms and conditions on which that direct control service or component are provided) where:

- the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation;
- the direct control service, except to the extent of any prescribed requirements of jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or 5.1 of the NER; or
- the direct control service is a connection service provided to serve network users at a single distribution network connection point, other than connection services that are provided by one network service provider to another network service provider to connect their networks where neither provider is a market network service provider.

In accordance with clauses 6.12.1(16B) and 6.7A.4(a) of the transitional chapter 6 rules the AER decides the NCC for EnergyAustralia is at appendix B of the draft decision.

In accordance with clauses 6.12.1(15) and 6.7A.3 of the transitional chapter 6 rules the AER decides the negotiating framework in appendix F of the draft decision is to apply to Integral Energy for the next regulatory control period. The preparation of the negotiating framework for 2014–2019 regulatory control period must be undertaken in accordance with the framework and approach processes for that regulatory control period.

In accordance with clause 6.12.1(16A) of the transitional chapter 6 rules the AER decides that the components of Integral Energy's direct control services which are negotiable components are any component of a direct control service (or the terms and conditions on which that direct control service or component are provided) where:

- the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation;

- the direct control service, except to the extent of any prescribed requirements of jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as set out in schedule 5.1a or 5.1 of the NER; or

- the direct control service is a connection service provided to serve network users at a single distribution network connection point, other than connection services that are provided by one network service provider to another network service provider to connect their networks where neither provider is a market network service provider.

In accordance with clause 6.12.1(16B) and 6.7A.4(a) of the transitional chapter 6 rules the AER decides the NCC for Integral Energy is at appendix B of the draft decision.

4 Control mechanisms for direct control services

4.1 Introduction

A distribution determination imposes controls over the prices, and revenues, that the NSW DNSPs may recover from providing direct control services. Direct control services are categorised as either standard control services or alternative control services. Classification of direct control services provided by the NSW DNSPs is discussed in chapter 2 of this decision.

The AER has published guidelines under clause 6.2.8(a)(2) of the transitional chapter 6 rules setting out the control mechanisms it proposes to apply to direct control services provided by the NSW DNSPs during the next regulatory control period. For the NSW DNSPs standard control services this mechanism is a weighted average price cap (WAPC). This chapter discusses how this mechanism will be applied and sets out how the AER will determine compliance with the mechanism during the regulatory control period.

The control mechanism and assessment of the NSW DNSPs' proposals regarding alternative control services is in chapter 17 of this decision.

4.2 Regulatory requirements

Clause 6.12.1 of the transitional chapter 6 rules requires the AER to make the following constituent decisions which are related to the form of control mechanism for standard control services:

- a decision on the control mechanism (including the X factor) for standard control services (clause 6.12.1(11))
- a decision on how compliance with the relevant control mechanism is to be demonstrated (clause 6.12.1(13))
- a decision on how the DNSP is to report to the AER on its recovery of TUOS charges for each regulatory year and adjustments to prices in subsequent years to account for TUOS over or under-recoveries (clause 6.12.1(19)).

For standard control services clause 6.2.6(a) of the transitional chapter 6 rules requires that the control mechanism must be of the prospective CPI minus X form, or some incentive–based variant of that form, in accordance with the building block approach.

Clause 6.2.5(c1)(1) of the transitional chapter 6 rules provides that the control mechanism for NSW DNSPs' standard control services must be substantially the same as the control mechanism determined by IPART for the corresponding prescribed distribution services in the current regulatory control period (the IPART control mechanism).[108] The control mechanism for standard control services may, with the agreement of the DNSP, apply differently for different categories of services. The IPART control mechanism is based on

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[108] IPART, *Final determination*, pp. 5–8.

the prospective CPI minus X form and the objectives and principles outlined in the National Electricity Code. The IPART control mechanism is a weighted average price cap.

Clause 6.2.5(c1)(3) of the transitional chapter 6 rules provides that the control mechanism for EnergyAustralia prescribed (transmission) standard control services must be substantially the same as that determined by the ACCC for the corresponding prescribed transmission services provided in the regulatory control period 2004–09.[109]

The AER published a guideline for standard control services (the standard control services guideline) that sets out the following control mechanisms for the NSW DNSPs for the next regulatory control period:[110]

- a WAPC for standard control services provided by the NSW DNSPs
- within the WAPC, a schedule of fees and/or charges for specific miscellaneous services, monopoly services and emergency recoverable works. The fees and/or charges will be escalated from current prices by P_0 and CPI adjustments, and will be fixed for the next regulatory control period
- a pass through of the transmission components of network prices
- a revenue cap for EnergyAustralia prescribed (transmission) standard control services.

This standard control services guideline is not binding on the AER or the NSW DNSPs, however, if the AER's distribution determination is not in accordance with the guideline it must state the reasons for its departure.[111]

4.3 NSW DNSP proposals

4.3.1 Country Energy proposal for standard control services

Country Energy calculated its revenue requirements and X factors for standard control services under a WAPC control mechanism. Country Energy proposed a schedule of fixed charges for miscellaneous and monopoly services for 2008–09 which are to be escalated and form part of the WAPC.[112] A schedule of prices was not provided for emergency recoverable works.

Country Energy noted that the AER's proposed approach to determining a schedule of charges for miscellaneous and monopoly services and emergency recoverable works is consistent with the approach adopted by IPART for the current regulatory control period. However, Country Energy stated that in future these charges should be analysed to ensure

109 EnergyAustralia's prescribed (transmission) standard control services are defined in clause 6.1.6(c) of the transitional chapter 6 rules.
110 AER, *Final decision: Control mechanisms for direct control services for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008.
111 Transitional chapter 6 rules, clause 6.2.8(c).
112 Country Energy, *Regulatory Proposal*, pp. 173–175.

they are cost reflective although it acknowledges that timing constraints (of the current review) require a need for simplicity in the charges for these services.[113]

4.3.2 EnergyAustralia's proposal for standard control services

EnergyAustralia stated that it has prepared its control mechanism in accordance with the AER's standard control services guideline. However it proposed the following departures from the guideline:[114]

- a variation in the treatment of miscellaneous fees and monopoly charges
- a minor amendment to the expression of the WAPC formula
- an amendment to the calculation of the X factor with respect to D factor and other incentive payments as it affects compliance with side constraints
- the exclusion of emergency recoverable works. It stated emergency recoverable works is not a distribution service and should not be regulated under the rules. If classified as a distribution service, emergency recoverable works should be reclassified from a standard control service to an unclassified service.

EnergyAustralia proposed to maintain the arrangements which were put in place by IPART for the review and submission of the WAPC and TUOS quantities to demonstrate compliance with the WAPC constraint and TUOS pass through calculations. It also proposed continuation of IPART's approach for using reasonable estimates to account for tariff restructuring, the introduction of new tariffs, and when customers move between existing tariffs.[115]

4.3.3 Integral Energy's proposal for standard control services

Integral Energy calculated its revenue requirements and X factors for standard control services under a WAPC control mechanism.[116] It raised specific issues with the TUOS pass throughs, the application of side constraints and the calculation of miscellaneous and monopoly services charges.[117]

Integral Energy sought clarification from the AER about whether it will use actual data to calculate the TUOS overs and unders amount from 2011–12 onwards.[118] It noted the AER previously stated that it would use actual data where available from the current regulatory control period to determine the TUOS overs and unders adjustment for each regulatory year.[119] Integral Energy supported the use of actual data as it eliminates forecasting risk.[120]

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113 Country Energy, *Regulatory proposal*, p. 173.
114 EnergyAustralia, *Regulatory proposal*, pp. 180 and 186.
115 EnergyAustralia, *Regulatory proposal*, Attachment 4.1, p.4.
116 Integral Energy, *Regulatory proposal*, pp. 173–174.
117 Integral Energy, *Regulatory proposal*, pp. 197–200.
118 Integral Energy, *Regulatory proposal*, p.199.
119 AER, *Final decision: control mechanisms for the ACT and NSW,* p. 8.
120 Integral Energy, *Regulatory proposal*, p. 199.

Integral Energy accepted the approach to side constraints set out in the AER's standard control services guideline. However it expressed concern about whether the wording of clause 6.18.6(b) allows such an approach as it implies that both price and volume changes need to be considered when assessing movements within the side constraint.[121]

Integral Energy proposed to increase prices for monopoly and miscellaneous services by the cumulative CPI from 2004–09 (14.4 per cent) and then index the prices by the annual CPI throughout the regulatory control period.[122]

For emergency recoverable works, Integral Energy proposed to use the pricing principles applied by the IPART 2004–09 determination.[123] These principles are:

- Integral Energy must not charge more than 110% of the actual costs of materials and plant associated with the repairs; plus
- No more than 150% of the actual labour costs associated with the repair, when calculated at the R2b (Inspector) hourly rate ($72 per hour).[124]

4.3.4 EnergyAustralia's proposal for prescribed (transmission) standard control services

EnergyAustralia proposed to recover revenues from EnergyAustralia prescribed (transmission) standard control services under a revenue cap control mechanism.[125]

4.4 Issues and AER considerations

4.4.1 NSW DNSP's standard control services

Weighted average price cap (WAPC)

For standard control services in NSW, the AER will apply the formula that was applied by IPART in the current regulatory control period with the following exceptions:[126]

1. The AER will not apply the price limits imposed by IPART (both those expressed in percentage terms and dollar terms).
2. The AER will apply a side constraint formula to each tariff class[127], this is a requirement of clause 6.18.6 of the transitional chapter 6 rules.[128]

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121 Integral Energy, *Regulatory proposal*, p. 199–200.
122 Integral Energy, *Regulatory proposal*, p. 177.
123 Integral Energy, *Regulatory proposal*, p. 177.
124 Integral Energy, *Regulatory proposal*, Appendix G, pp. 6–7.
125 EnergyAustralia, *Regulatory proposal*, p. 186.
126 AER, *Guideline on control mechanisms for direct control services for the ACT and NSW 2009 distribution determination*, February 2008, p. 7.
127 The standard control services guideline was written using terminology from IPART's *NSW Electricity Distribution Pricing 2004–05 to 2008–09: Final Determination*. The terminology used in this chapter reflects the terminology used in the NER. For example, references in this chapter to 'side constraints for tariff classes' equates to the concept of 'side constraints to the prescribed distribution service charges' which is used in the standard control services guideline.
128 The side constraint formula is provided at appendix A of AER, *Guideline on control mechanisms for direct control services for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008.

3. In assessing compliance with the above side constraint, the AER will disregard:

- the recovery of revenue to accommodate a variation to the distribution determination under clause 6.6 or 6.13

- the recovery of revenue to accommodate pass through of charges for TUOS services to customers.

4. The AER will redefine the year references within the WAPC formula applied by IPART in the current regulatory control period. IPART's year *t+1* will become year *t*, year *t–1* will become year *t–2*, and so on[129]

5. Minor amendments to the calculation of the CPI minus X constraint (discussed below)

The WAPC formula applied by IPART in the current regulatory control period that the AER will apply subject to the above exceptions in the next regulatory control period is:

$$\frac{\sum_{i=1}^{n}\sum_{k=1}^{m} p_{ik}^{t} \times q_{ik}^{t-2}}{\sum_{i=1}^{n}\sum_{k=1}^{m} p_{ik}^{t-1} \times q_{ik}^{t-2}} \leq (1+\Delta CPI)\times(1-X_t)\times(1+D_t) \qquad \mathrm{i}=1,...,\mathrm{n} \text{ and } \mathrm{k}=1,...,\mathrm{m}.$$

Where: The DNSP has *n* relevant tariff classes which each have up to *m* components:

p_{ik}^{t} is the proposed price for component *k* of the relevant tariff *i* for year *t*

p_{ik}^{t-1} is the actual price for component *k* of the relevant tariff *i* for year *t–1* (being the year which immediately precedes year *t*)

q_{ik}^{t-2} is the audited quantity of component *k* of the relevant tariff *i* that was charged by the DNSP in year *t–2* (being the year immediately preceding year *t–1*)

X_t is the allowed real change in average prices from year *t–1* to year *t* of the regulatory control period as determined by the AER

D_t is the demand management cost recovery factor for year *t* calculated to recover certain approved demand management implementation costs and foregone revenue incurred in year *t–2*[130]

[129] AER, *Final decision: Control mechanisms for direct control services,* p. 12.

[130] AER, *Final decision: Demand management incentive schemes for the ACT and NSW 2009 distribution determinations*, February 2008, Appendix C. The AER decided to apply the D-factor scheme as applied by IPART in its 2004 determination. The calculation of the D-factor term in the WAPC is set out in IPART, *NSW Electricity Distribution Pricing Final Report*, p. 99.

ΔCPI means the number derived from the application of the following formula:

$$\Delta CPI = \left[\frac{CPI_{Mar,t-2} + CPI_{June,t-2} + CPI_{Sept,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-3} + CPI_{June,t-3} + CPI_{Sept,t-2} + CPI_{Dec,t-2}} - 1 \right]$$

Where:

CPI means the all groups index number for the weighted average of eight capital cities as published by the Australia Bureau of Statistics (ABS), or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index

t refers to a nominal year

$CPI_{month(year)}$ means the CPI for the quarter and the year indicated.

Minor amendment to the expression of the WAPC formula

EnergyAustralia proposed a minor amendment to the expression of the WAPC formula which removes the need for the double sigma in the formula. EnergyAustralia stated that it has taken all the components across all tariffs and sequentially numbered them, dispensing with numbering each tariff and then numbering the components as well.[131]

The AER considers that maintaining consistency with IPART's approach—that is, adopting where possible the same formula—to be important. Given that the formula in the AER's standard control guideline is consistent with that employed by IPART and recognising that it appears that EnergyAustralia's formula is mathematically the same, the AER sees no reason to depart from its guideline and does not accept EnergyAustralia's amendment to the expression of the WAPC formula.

The CPI minus X constraint applied to the WAPC differs slightly from the expression used by IPART and the AER's standard control services guideline by:

- recognising X values as negative amounts in accordance with the 'CPI minus X' expression required under clause 6.2.6 (previously was expressed as (CPI+X))

- incorporating X in a multiplicative sense i.e. (1+CPI)*(1-X), as per standard regulatory practice and consistent with the form envisaged in the application of side constraints under clause 6.18.6 (was previously expressed as (1+CPI-X))

The AER notes that these changes are not substantive and are also consistent with the NSW DNSPs' proposed calculations of X factors contained in their PTRMs.

Amendment to expression of the X factor

EnergyAustralia proposed that the X in the WAPC formula should be re-defined to include D factor and other incentive payments i.e. the 'X_{ADJ}' in the following formula:[132]

$$CPI - X_{ADJ} = CPI - X + D + (\text{other incentives})$$

[131] EnergyAustralia, *Regulatory proposal*, Attachment 4.1, p. 3.
[132] EnergyAustralia, letter to AER, 1 August 2008, pp. 4–5.

This adjustment is proposed to rectify a perceived conflict between the WAPC mechanism and the side constraint as set out in clause 6.18.6. That is, the X_{ADJ} is intended to be used for assessing compliance with the side constraint in this clause.

EnergyAustralia is concerned that the application of side constraints, by not recognising the impact of incentive payments, would inhibit its ability to rebalance prices and implement tariff reform. Specifically, it expects price adjustments in the order of 0.5 per cent arising from the D factor, leaving it only 1.5 per cent “headroom” for individual price adjustments under the side constraint.[133] EnergyAustralia further noted that this issue is compounded by revenue adjustments arising out of the efficiency benefit sharing scheme.

The AER notes that clause 6.18.6(d) explicitly requires the AER to disregard adjustments to revenues arising because of incentive payments and pass through amounts when assessing compliance with side constraints. That is, if a DNSP was required to impose an increase in prices because of a D factor adjustment (or other adjustments arising out of clause 6.6 or 6.13) the AER would disregard this increase in assessing compliance under 6.18.6(c). For this reason, EnergyAustralia’s proposed redefinition of X appears to be unnecessary.

Recovery of transmission use of system costs

Clause 6.18.7 of the transitional chapter 6 rules allows each DNSP to recover its actual transmission related payments, through TUOS charges. Transmission related payments include:

- transmission charges paid to TNSPs for use of transmission system;
- avoided TUOS paid to embedded generators; and
- payments made to other DNSPs for use of their network,

and are net of transmission settlement residue payments.[134]

TUOS charges are based on a forecast of the transmission related payments for each year, as well as a ‘pass through’ of any under or over recovery of charges for the previous regulatory year.[135] Because the amount of any under or over recovery for a particular year is not known at the time prices for the subsequent year are set, there is typically a lag of one year in correcting for this difference. For example, where there is a difference between the forecast and actual transmission related payments resulting in an over or under recovery of TUOS charges for year *t–2*, DNSPs will only be able to recover or return this amount when setting prices for year *t*.

The AER confirms that it will use actual data to calculate TUOS pass through amounts during the next regulatory control period, including information relating to revenues from 2009–10 onwards. However, the amount of an under or over-recovery of TUOS charges in any year (e.g. year ‘t’) cannot be taken into account through price adjustments until at

[133] EnergyAustralia, letter to AER, 1 August 2008, p. 4.
[134] AER, *Guideline on control mechanisms for direct control services*, Appendix B, p. 12.
[135] Transitional chapter 6 rules, clause 6.18.7(b).

least two years hence (e.g. year 't+2'). For this reason any adjustments for under or over-recovery of revenues in the last two years of the next regulatory control period (i.e. 2012–13 and 2013–14) will not form part of price adjustments during that period.

The reporting and administration of unders and overs balances is detailed in appendix I of this draft decision and represents a departure from the arrangements put in place by IPART for the NSW DNSPs for the current regulatory control period, with respect to using actual (and not estimated) data on under or over-recoveries.

Side constraints

Clause 6.18.6(b) of the transitional chapter 6 rules provides that the expected weighted average revenue to be raised from a tariff class for a particular year of a regulatory control period must not exceed the previous year's weighted average revenue by more than the permissible percentage. The permissible percentage is defined in clause 6.18.6(c) as the greater of:

1. CPI-X limitation on any increase in the DNSP's expected weighted average revenue between the two years plus 2%; or
2. CPI plus 2%.

In determining compliance with the above side constraint, the AER will disregard:

- the recovery of revenue to accommodate a variation to the distribution determination under clause 6.6 or 6.13[136]
- the recovery of revenue to accommodate pass through of charges for TUOS services to customers.[137]

The side constraint formula applicable to each tariff class of standard control services is as follows:[138]

$$\frac{\sum_{k=1}^{m} d_k^t \times q_k^{t-2}}{\sum_{k=1}^{m} d_k^{t-1} \times q_k^{t-2}} \leq 1 + \Delta CPI + L_t \qquad \text{k} = 1,\ldots,\text{m}.$$

Where: The tariff class has up to *m* components:

d_k^t is the proposed price for component *k* of the tariff class for year *t*

d_k^{t-1} is the price charged by the DNSP for component *k* of the tariff in year *t–1*

136 Clause 6.6 relates to cost pass throughs, service target performance incentive scheme and demand management incentive scheme; and clause 6.13 relates to revocation and substitution of a distribution determination for wrong information or error.

137 Transitional chapter 6 rules, clause 6.18.6(d).

138 AER, *Guideline on control mechanisms for direct control services*, Appendix A, p. 10.

q_k^{t-2} is the audited quantity of component *k* of the tariff that was charged by the DNSP in year *t–2*

L_t is the permissible real percentage change in the expected weighted average revenue of a tariff class from year *t–1* to year *t* of the regulatory control period, determined in accordance with clause 6.18.6 (c) of the transitional Chapter 6 rules

ΔCPI means the number derived from the application of the following formula:

$$\Delta CPI = \left[\frac{CPI_{\ March(t-2)} + CPI_{\ June(t-2)} + CPI_{\ September(t-1)} + CPI_{\ December(t-1)}}{CPI_{\ March(t-3)} + CPI_{\ June(t-3)} + CPI_{\ September(t-2)} + CPI_{\ December(t-2)}} - 1 \right]$$

Where:

CPI means the all groups index number for the weighted average of eight capital cities as published by the Australia Bureau of Statistics (ABS), or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index

$CPI_{\ (month),(year)}$ means the CPI for the quarter and the year indicated.

Integral Energy raised concerns about the wording of clause 6.18.6(b) and implied volume changes. The AER's proposed formula does not consider changes in volumes as the quantity weightings applied in the formula are from the same year (i.e. from year "t–2" in the above formula). The AER's justification for using historical quantity weights in calculating changes in expected weighted average revenue relates to the advantages as noted by NERA.[139] The AER's ability to choose particular weightings was noted by MCE SCO, when considering issues raised in response to the draft amendments to the NER regarding distribution regulation.[140] Further, by using the same year's quantity weights the AER's formula is also consistent with that applied by IPART.

Demonstration of compliance with the WAPC

EnergyAustralia proposed to maintain IPART's arrangements for the review and estimation of quantity data used to demonstrate compliance with the WAPC constraint and TUOS pass through calculations.[141]

The AER considers that the continuation of IPART's approach is consistent with AER requirements relating to the audit of historical quantity data.[142] It also considers that IPART's approach to the assessment of reasonable estimates for sales quantities is also appropriate for the purposes of demonstrating compliance with the WAPC constraint. The AER considers that IPART's approach to these matters should be maintained for the next

139 NERA, *Distribution Pricing Rule Framework – Network Policy Working Group*, December 2006, pp. 45–46.

140 MCE, *Energy Market Reform Bulletin No. 95 - SCO Response to Submissions on the Draft of the National Electricity Rules*, response number 203, 1 August 2007.

141 EnergyAustralia, *Regulatory proposal*, Attachment 4.1, pp. 4–5.

142 AER, *Final Decision, Control mechanism for direct control services,* section 5.4.

regulatory control period. [143] The requirement for demonstrating compliance with the WAPC is set out in appendix J of this decision.

Miscellaneous services, monopoly services and emergency recoverable works

Miscellaneous services are 'non-routine' services related to the distribution of electricity and include special meter readings, meter testing and disconnection for non-payment. Monopoly services are those related to extensions, augmentations or connections to the network that only DNSPs can perform. For example, design checking, installation inspection and energising/de-energising the network.[144] Emergency recoverable works are emergency works undertaken by a DNSP to repair damage to its distribution system that has been caused by a person who is liable for the damage (eg. a motor vehicle colliding with a pole where the driver was negligent).[145]

These services were determined by IPART as prescribed distribution services in its June 2004 Final Determination. A more detailed description of the individual services which make up each service category is set out in appendix G of this draft decision.[146]

Clause 6.2.3B of the transitional chapter 6 rules provides that distribution services determined by IPART to be prescribed distribution services for the current regulatory control period are deemed to be classified as standard control services for the next regulatory control period.

AER's standard control services guideline

The AER envisaged that the WAPC formula would apply to the distribution component of network prices (including DUOS tariffs) and the fees and charges for miscellaneous services, monopoly services and emergency recoverable works. These fees and charges, in addition to counting towards the WAPC constraint, are set out in a fixed schedule of fees and/or charges set out in the distribution determination.[147] The schedule would be calculated by escalating the current fees and/or charges from current prices by P_0 and CPI adjustments and would be fixed for the regulatory control period.[148]

EnergyAustralia's proposed treatment of the services differs to that set out in the AER's standard control services guideline in that:

- the prices of emergency recoverable works would be excluded from any form of control
- miscellaneous and monopoly services would not be determined in a schedule of charges, but could vary along with other distribution prices subjected to the WAPC.[149]

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143 IPART, *NSW Electricity Distribution Pricing Final Report*, Appendix 5.
144 IPART, *NSW Electricity Distribution Pricing Final Report*, p. 109.
145 IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination*, June 2004, annexure 2, p. 50.
146 These definitions are based on those used by IPART which are set out in annexure 2 of its *NSW Electricity Distribution Pricing Final Determination*.
147 AER, *Final decision*: *Control mechanisms for direct control services*, pp. 9–10.
148 AER, *Final decision: Control mechanisms for direct control services*, p.10.
149 EnergyAustralia, *Regulatory proposal*, p. 185.

EnergyAustralia's proposal that emergency recoverable works is not a distribution service and should not be regulated is discussed in chapter 2 of this decision. EnergyAustralia's alternative proposal that emergency recoverable works be reclassified from a standard control service to an unclassified service is also discussed in chapter 2 of this decision. The AER has not been satisfied that emergency recoverable works is not a distribution service and notes the example given by EnergyAustralia is unlikely to be able to be performed by another entity. It has decided not to reclassify emergency recoverable works. Therefore, the prices of emergency recoverable works will not be excluded from any form of control in the next regulatory control period.

EnergyAustralia's proposal that miscellaneous and monopoly services could vary along with other distribution prices subjected to the WAPC is discussed below.

New category of miscellaneous service as proposed by EnergyAustralia

EnergyAustralia proposed an additional category of miscellaneous service for disconnection via service fuse removal.[150] This category of service arose during the current regulatory control period. EnergyAustralia noted that the normal practice for disconnection during a customer move-out is for a meter reader to turn off the supply at the main switch and place a disconnection sticker across the switch. This is what is done by EnergyAustralia under IPART's miscellaneous service of disconnection at meter box.[151] EnergyAustralia noted in its regulatory proposal that in a limited number of circumstances it has agreed to a retailer's request for a disconnection by removing the sealed service fuse. EnergyAustralia noted there are additional costs associated with this method of disconnection but the additional costs are not allowed for in IPART's price list for miscellaneous services.[152] As a consequence, EnergyAustralia proposed that the miscellaneous service of disconnection at meter box be broken into two services, disconnection at meter box via main switch and disconnection at meter box via service fuse removal. EnergyAustralia stated that this will allow it to optimise its resources in providing the services and retailers will be able to decide on the level of service they require.[153]

EnergyAustralia has subsequently advised the AER that its regulatory proposal confused fuse removal disconnections at the meter box with fuse removal disconnection at the bargeboard. It was disconnection at the bargeboard which required more qualified staff and therefore additional costs. EnergyAustralia also advised that it no longer carries out such disconnections for safety reasons. EnergyAustralia has confirmed that the costs are the same for disconnections at the meter box via fuse removal and by using a tape across the main switch.[154]

The AER does not accept EnergyAustralia's proposal for this new category of miscellaneous service because the cost of providing the service is the same as for disconnecting at the main switch. The AER notes that the description for the miscellaneous service of disconnection at meter box set out in appendix G covers

150 EnergyAustralia, *Regulatory proposal*, Attachment 13.1 (confidential). p. 3.
151 EnergyAustralia, *Regulatory proposal*, Attachment 13.1 (confidential), sections 2.6 and 2.11.
152 EnergyAustralia, *Regulatory proposal*, Attachment 13.1 (confidential), section 2.11.
153 EnergyAustralia, *Regulatory proposal*, Attachment 13.1 (confidential), section 5.4(c).
154 EnergyAustralia, email, *Re: Questions regarding proposed miscellaneous service for disconnection at meter box via service fuse removal*, 30 September 2008.

disconnections via the main switch and service fuse removal. IPART used the same description in its 2004–09 determination.[155]

Miscellaneous and monopoly services as elements of the WAPC and the escalation factor to use in escalating the current fees for the services

EnergyAustralia proposed that miscellaneous and monopoly services be considered as elements of the WAPC in the same way as tariffs for the use of the network. This would include miscellaneous and monopoly services being subject to the pricing side constraint and permitting the introduction of new miscellaneous and monopoly components.[156] Miscellaneous and monopoly services would not be determined in a schedule of charges but could vary along with other distribution prices subjected to the WAPC.

Country Energy proposed that the AER should adopt both the CPI and a labour escalation factor for miscellaneous and monopoly services charges. The labour escalation rate proposed is contained in the report by CEG and discussed in appendix N of this decision.

Integral Energy proposed to increase prices for monopoly and miscellaneous services by the cumulative CPI from 2004–09 and then index the prices by the annual CPI throughout the next regulatory control period.

The AER notes that truncated timelines apply to the NSW distribution determinations for the next regulatory control period. As a consequence, the AER has decided that it would be more appropriate to undertake an analysis of miscellaneous and monopoly charges (including labour escalation rates) as part of the distribution determination for the 2014–2019 regulatory control period. This will give the AER an opportunity to assess whether the charges are at cost reflective levels.

The AER noted in the standard control services guideline that the services will be regulated under the WAPC and will be part of the determination process which takes into account forecast input costs and allows DNSPs to rebalance their tariffs. The AER also noted that while the charges for the services may be fixed, the total revenue to be recovered is based on the DNSPs forecast building block costs and will be recoverable in total over the regulatory control period.[157] Therefore, the AER does not accept EnergyAustralia's proposal that charges for miscellaneous and monopoly services be considered as elements of the WAPC in the same way as tariffs for the use of the network. In addition the AER does not accept Country Energy's proposal to adopt a labour escalation rate for miscellaneous and monopoly services for the next regulatory control period.

As foreshadowed in the standard control services guideline the AER considers that by applying a P_0 and CPI adjustment at the beginning of the next regulatory control period it will not be necessary to escalate the charges each year during the period. The AER considered that the escalation will allow the services to have a net present value (NPV) neutral impact on DNSPs' revenues.[158] The AER notes that a NPV neutral position will only be achieved if actual CPI equates to that forecast. Therefore the AER does not accept

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155 IPART, *NSW electricity distribution pricing Final determination*, annexure 2, p. 46.
156 EnergyAustralia, *Regulatory proposal*, p. 185.
157 AER, *Final decision*: *Control mechanisms for direct control services*, p. 9.
158 AER, *Final decision*: *Control mechanisms for direct control services*, p. 9.

Integral Energy's proposal to index the prices by the annual CPI throughout the next regulatory control period. However, in accordance with the standard control services guideline, the AER will apply P_0 (taking account of estimated inflation in the next regulatory control period) and CPI adjustments (taking account of inflation in the current regulatory control period) at the beginning of the next regulatory control period. This, in theory, should achieve the same outcome as that proposed by Integral Energy. As stated in the standard control services guideline, publishing a schedule of fees and charges which are fixed over the regulatory control period will provide transparency and avoid complexity.[159]

In relation to emergency recoverable works, the AER will use the pricing principles applied by the IPART 2004-09 determination[160] and the underlying labour rate will be escalated by P_0 and CPI adjustments and will be fixed for the next regulatory control period as set out in appendix H of this decision.

Schedule of fees and/charges for miscellaneous services, monopoly services and emergency recoverable works

The schedule of fees and/or charges for miscellaneous services, monopoly services and emergency recoverable works for the next regulatory control period is set out in appendix H of this decision. In accordance with the standard control services guideline, the AER has determined that the fees and/or charges will be escalated from current prices by P_0 and CPI adjustments and will be fixed for the next regulatory control period.[161] The fees and charges will be adjusted to reflect movements in the CPI from 1 July 2004 when the charges were set by IPART[162] (CPI adjustment) and for estimated movements in the CPI for the last regulatory year of the current regulatory control period and for the next regulatory control period (P_0 adjustment).

4.4.2 EnergyAustralia prescribed (transmission) standard control services

The AER will apply the same revenue cap formula to EnergyAustralia prescribed (transmission) standard control services as that applied by the ACCC in the current regulatory control period to EnergyAustralia's transmission services.

The revenue cap formula applied by the ACCC is outlined in the AER's standard control services guideline.[163]

$$MAR = (AR_t) \pm \left[\frac{\left(AR_{t-1} + AR_{t-2}\right)}{2} \times S_{ct} \right] \pm (pass\ through)$$

Where:

MAR is the maximum allowed revenue;

AR is the annual revenue;

159 AER, *Final decision*: *Control mechanisms for direct control services*, p. 9.
160 IPART, *NSW Electricity Distribution Pricing Final determination*, annexure 3, section 5.
161 AER, *Final decision*: *Control mechanisms for direct control services*, p. 11.
162 IPART, NSW Electricity Distribution Pricing Final determination, annexure 3.
163 AER, *Guideline on control mechanisms for direct control services*, p. 6.

S is the service standards factor;

t is the time period on a financial year basis; and

c_t is the time period on a calendar year basis.

The AER may allow adjustments to the revenue cap for EnergyAustralia prescribed (transmission) standard control services for revenue increments or decrements as a result of a service target performance incentive scheme (STPIS).[164] The AER notes that no STPIS will apply to EnergyAustralia for the next regulatory control period and therefore no revenue implications arising from the application of the STPIS will result except in relation to increments and decrements associated with the carryover of the STPIS for transmission. Therefore, the term

$$\left[\frac{(AR_{t-1} + AR_{t-2})}{2} \times S_{ct}\right]$$

in the above formula will only apply in relation to increments or decrements relating to the carryover of the STPIS for transmission.[165]

The transitional chapter 6 rules do not allow adjustments to the revenue cap for contingent projects. However, adjustments for pass through events are allowed and the AER will provide for adjustments to the revenue cap for any pass through events defined in the transitional chapter 6 rules or in its distribution determination.

The transitional chapter 6 rules provide that the pricing arrangements under chapter 6A, rather than transitional chapter 6, will apply to EnergyAustralia prescribed (transmission) standard control services. Therefore, the side constraints required under the transitional chapter 6 rules will not be applied to the pricing arrangements for these services.[166]

4.5 AER conclusions

The AER will apply the following WAPC formula to the NSW DNSPs standard control services for the next regulatory control period:

$$\frac{\sum_{i=1}^{n}\sum_{k=1}^{m} p_{ik}^{t} \times q_{ik}^{t-2}}{\sum_{i=1}^{n}\sum_{k=1}^{m} p_{ik}^{t-1} \times q_{ik}^{t-2}} \le (1+\Delta CPI)\times(1-X_t)\times(1+D_t) \qquad \mathrm{i}=1,\ldots,\mathrm{n} \text{ and } \mathrm{k}=1,\ldots,\mathrm{m}.$$

Where: The DNSP has *n* relevant tariff classes which each have up to *m* components:

164 AER. *Guideline on control mechanisms for direct control services*, p. 6.

165 AER, *Service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations: Final decision,* Canberra, February 2008, p. 15.

166 AER, *Guideline on control mechanisms for direct control services*, p. 6.

p_{ik}^{t} is the proposed price for component *k* of the relevant tariff *i* for year *t*

p_{ik}^{t-1} is the actual price for component *k* of the relevant tariff *i* for year *t–1* (being the year which immediately precedes year *t*)

q_{ik}^{t-2} is the audited[167] quantity of component *k* of the relevant tariff *i* that was charged by the DNSP in year *t–2* (being the year immediately preceding year *t–1*)

X_t is the allowed real change in average prices from year *t–1* to year *t* of the regulatory control period as determined by the AER

D_t is the demand management cost recovery factor for year *t* calculated to recover certain approved demand management implementation costs and foregone revenue incurred in year *t–2*[168]

ΔCPI means the number derived from the application of the following formula:

$$\Delta CPI = \left[\frac{CPI_{Mar,t-2} + CPI_{June,t-2} + CPI_{Sept,t-1} + CPI_{Dec,t-1}}{CPI_{Mar,t-3} + CPI_{June,t-3} + CPI_{Sept,t-2} + CPI_{Dec,t-2}} - 1\right]$$

Where:

CPI means the all groups index number for the weighted average of eight capital cities as published by the Australia Bureau of Statistics (ABS), or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index

t refers to a nominal year

$CPI_{month(year)}$ means the CPI for the quarter and the year indicated.

The AER will apply the following side constraint formula to each tariff class of standard control services provided by the NSW DNSPs:[169]

$$\frac{\sum_{k=1}^{m} d_k^{t} \times q_k^{t-2}}{\sum_{k=1}^{m} d_k^{t-1} \times q_k^{t-2}} \leq 1 + \Delta CPI + L_t \qquad \mathrm{k} = 1,...,\mathrm{m}.$$

Where: The tariff class has up to *m* components:

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167 AER, *Final decision*: *Control mechanisms for direct control services*, p. 11.

168 AER, *Final decision: Demand management incentive schemes for the ACT and NSW 2009 distribution determinations*, February 2008, appendix C. The AER decided to apply the D-factor scheme as applied by IPART in its 2004 determination. The calculation of the D-factor term in the WAPC is set out in IPART, *NSW Electricity Distribution Pricing Final report*, June 2004, p. 99.

169 AER, *Guideline on control mechanisms for direct control services*, Appendix A, p. 10.

d_k^t is the proposed price for component *k* of the tariff class for year *t*

d_k^{t-1} is the price charged by the DNSP for component *k* of the tariff in year *t–1*

q_k^{t-2} is the audited quantity of component *k* of the tariff that was charged by the DNSP in year *t–2*

L_t is the permissible real percentage change in the expected weighted average revenue of a tariff class from year *t–1* to year *t* of the regulatory control period, determined in accordance with clause 6.18.6 (c) of the transitional Chapter 6 rules

ΔCPI means the number derived from the application of the following formula:

$$\Delta CPI = \left[\frac{CPI_{March(t-2)} + CPI_{June(t-2)} + CPI_{September(t-1)} + CPI_{December(t-1)}}{CPI_{March(t-3)} + CPI_{June(t-3)} + CPI_{September(t-2)} + CPI_{December(t-2)}} - 1\right]$$

Where:

CPI means the all groups index number for the weighted average of eight capital cities as published by the Australia Bureau of Statistics (ABS), or if the ABS does not or ceases to publish the index, then CPI will mean an index which the AER considers is the best estimate of the index

$CPI_{(month),(year)}$ means the CPI for the quarter and the year indicated.

The AER has decided that the schedule of fees and/or charges for miscellaneous services, monopoly services and emergency recoverable works for the next regulatory period is set out in appendix H of this decision. The schedule of charges that apply under the IPART 2004–09 determination have been escalated to take into account CPI movements over the current regulatory control period and an estimate for CPI movements in the next regulatory control period. The escalation will be updated to reflect actual CPI at the time of the final decision.

The AER will apply the following revenue cap formula to EnergyAustralia prescribed (transmission) standard control services:

$$MAR = (AR_t) \pm \left[\frac{(AR_{t-1} + AR_{t-2})}{2} \times S_{ct}\right] \pm (pass\ through)$$

Where:

MAR is the maximum allowed revenue;

AR is the annual revenue;

S is the service standards factor;

t is the time period on a financial year basis; and

c_t is the time period on a calendar year basis.

4.6 AER draft decision

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules, the AER decides that the control mechanism for standard control services provided by Country Energy is a weighted average price cap. The applicable formulas are set out in section 4.5 of the draft decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules, the AER decides that Country Energy's:

- miscellaneous services, monopoly services and emergency recoverable works for the next regulatory period are set out in appendix G of the draft decision
- schedule of fees and/charges for miscellaneous services, monopoly services and emergency recoverable works for the next regulatory period are set out in appendix H of the draft decision.

In accordance with clause 6.12.1(19) of the transitional chapter 6 rules the AER decides that Country Energy must submit, as part of its annual pricing proposal, a record of the amount of revenues recovered from TUOS charges and associated payments in accordance with appendix I of the draft decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules, the AER decides that the control mechanism for standard control services provided by EnergyAustralia is a weighted average price cap. The applicable formulas are set out in section 4.5 of the draft decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules, the AER decides that EnergyAustralia's:

- miscellaneous services, monopoly services and emergency recoverable works for the next regulatory period are set out in appendix G of the draft decision
- schedule of fees and/charges for miscellaneous services, monopoly services and emergency recoverable works for the next regulatory period are set out in appendix H of the draft decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules, the AER decides that the control mechanism for EnergyAustralia prescribed (transmission) standard control services is set out in the standard control services guideline.

In accordance with clause 6.12.1(19) of the transitional chapter 6 rules the AER decides that EnergyAustralia must submit, as part of its annual pricing proposal, a record of the amount of revenues recovered from TUOS charges and associated payments in accordance with appendix I of the draft decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules, the AER decides that the control mechanism for standard control services provided by Integral Energy is a weighted average price cap. The applicable formulas are set out in section 4.5 of the draft decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules, the AER decides that Integral Energy's:

- miscellaneous services, monopoly services and emergency recoverable works for the next regulatory period are set out in appendix G of the draft decision
- schedule of fees and/charges for miscellaneous services, monopoly services and emergency recoverable works for the next regulatory period are set out in appendix H of the draft decision.

In accordance with clause 6.12.1(19) of the transitional chapter 6 rules the AER decides that Integral Energy must submit, as part of its annual pricing proposal, a record of the amount of revenues recovered from TUOS charges and associated payments in accordance with appendix I of the draft decision.

In accordance with clause 6.12.1(13) of the transitional chapter 6 rules, the AER decides that the NSW DNSPs must demonstrate compliance with the standard control services control mechanism in accordance with appendices I and J of this decision.

5 Opening asset base

5.1 Introduction

This chapter sets out the method used by the AER to determine the closing regulatory asset base (RAB) for each NSW DNSP for the current regulatory control period. The closing RAB becomes the opening RAB for the next regulatory control period and is used to calculate the annual building block revenue requirements.

5.2 Regulatory requirements

Clause 6.5.1 and schedule 6.2 of the transitional chapter 6 rules outline the approach that is used to determine the opening RAB for a distribution determination. The AER published an asset base roll forward model (RFM).[170] This RFM sets out the method for determining the roll forward of the RAB as required by clause 6.5.1(e).

Clauses 6.5.1(h) and 6.5.1(e)(1) of the transitional chapter 6 rules provide that for the first year of the next regulatory control period, the RFM for EnergyAustralia's transmission network assets must be applied as if the AER was separately regulating EnergyAustralia's transmission system under the relevant provisions of chapter 6A. Consequently, the regulatory requirements in the transitional chapter 6 rules outlined below do not apply to EnergyAustralia's transmission network assets that are deemed to be part of its distribution network under clause 6.1.6(b).[171]

Clause S6.2.1(c) of the transitional chapter 6 rules provides that the RAB for the first year of the regulatory control period must be determined by rolling forward the RAB values (as at 1 July 2004) set out in the schedule:

- Country Energy—$2440 million
- EnergyAustralia—$4116 million for its distribution network and $636 million in respect of its transmission network
- Integral Energy—$2283 million.

These values are to be adjusted to allow for the difference between estimated capex and actual capex in the previous regulatory control period. Clause S6.2.1(c)(3) provides that when rolling forward the RAB '…the AER must take into account the derivation of the values in the above table [schedule] from past regulatory decisions and the consequent fact that they relate only to the RAB identified in those decisions from past regulatory decisions'. Clause S6.2.1(e) of the transitional chapter 6 rules outlines how these values are further adjusted to roll forward and calculate the RABs at the beginning of the first year of the next regulatory control period.

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170 AER, *Roll forward model for electricity distribution – NSW DNSPs for 2009–14 period*, January 2008.

171 While EnergyAustralia's transmission network support assets are subject to the requirements of chapter 6A, the roll forward methodology under chapter 6A is broadly consistent with the requirements outlined with respect to the DNSPs.

5.2.1 Country Energy deferred depreciation

Clause S6.2.1(g) stipulates that the RAB for Country Energy at the beginning of the next regulatory control period should reflect the deferral of depreciation allowed for Country Energy in clause 7.3.2 of IPART's final determination relating to NSW electricity distribution pricing for the current regulatory control period.

5.3 NSW DNSP proposals

5.3.1 Country Energy

Country Energy proposed an opening RAB for the next regulatory control period of $4236 million as at 1 July 2009.[172] The proposed opening RAB includes capex of $2206 million incurred during the current regulatory control period.[173]

The proposed RAB includes downward adjustments of $10 million for the difference between actual and forecast capex in 2003–04 and the associated return on that difference, and $35 million for asset disposals over the current regulatory control period. Further, an adjustment of $477 million has been made for depreciation based on the actual capex. There is an additional upward adjustment to the proposed RAB of $112 million for deferred depreciation, which was allowed for in the 2004 IPART determination.[174] The proposed opening RAB has also been indexed for actual inflation using the consumer price index (CPI).[175]

Country Energy also provided information to support an increase to its proposed opening RAB of $296 million for assets omitted from the previous RAB valuation. Country Energy stated that 'a number of material inaccuracies existed in the initial 1999 asset valuation, and these have perpetuated through into subsequent roll forward valuations.'[176] Country Energy did not include the $296 million for omitted assets in its proposed RAB within the RFM or post-tax revenue model (PTRM).

5.3.2 EnergyAustralia

EnergyAustralia proposed an opening RAB for the next regulatory control period of $8218 million as at 1 July 2009.[177] This is comprised of $7229 million for its distribution opening RAB and $989 million for its transmission opening RAB.[178] The proposed distribution opening RAB includes capex of $3390 million incurred during the current regulatory control period.

The proposed distribution RAB includes downward adjustments of $43 million for the difference between actual and forecast capex in 2003–04, and the associated return on that difference, and $55 million for asset disposals over the current regulatory control

172 Country Energy, *Regulatory Proposal*, p. 158.
173 Country Energy, *Regulatory proposal*, p. 157.
174 IPART, *Final Report (Other Paper No 23 – June 2004) relating to NSW Electricity Distribution Pricing 2004/05 to 2008/09*, clause 7.3.2.
175 Country Energy, *Regulatory proposal*, p. 157.
176 Country Energy, *Regulatory proposal*, p. 176.
177 EnergyAustralia, *Regulatory proposal*, p. 27.
178 EnergyAustralia, *Regulatory proposal*, attachment 1.1, post tax revenue model; attachment 1.2, distribution and transmission RAB roll forward models.

period. The distribution RAB has also been reduced by depreciation of $333 million based on the actual capex incurred during the current regulatory control period and an adjustment of $57 million for system assets moved from distribution to transmission.[179]

For transmission assets, the proposed opening RAB includes capex of $348 million and has been reduced by depreciation of $37 million based on the actual capex incurred during the current regulatory control period. It also includes downward adjustments of $3 million for asset disposals and $15 million for non–system asset re-allocation. A further adjustment of $57 million for the assets transferred from distribution increases the transmission RAB.[180]

5.3.3 Integral Energy

Integral Energy proposed an opening RAB for the next regulatory control period of $3835 million as at 1 July 2009.[181] The proposed opening RAB includes capex of $1956 million, net of capital contributions, incurred during the current regulatory control period.[182]

The proposed RAB includes downward adjustments of $46 million for asset disposals and $434 million for depreciation based on the actual capex.[183] It has also been adjusted downwards by $95 million for the difference between actual and forecast capex in 2003–04, and the associated return on that difference over the current regulatory control period.

Integral Energy has proposed an increase of $170 million for erroneous asset lives applied to its opening RAB. This issue was considered and not approved as part of the 2004 IPART determination.[184] This figure was not included in the RFM by Integral Energy. However, Integral Energy adjusted the opening RAB value in the PTRM to include the $170 million adjustment.

5.4 Issues and AER considerations

5.4.1 Opening asset value—1 July 2004

Clause S6.2.1(c) of the transitional chapter 6 rules states that the DNSPs' opening RAB (as at 1 July 2004) must be rolled forward to determine the opening RAB as at 1 July 2009, subject to clauses S6.2.1(c)(2) and (3).

The timing of a distribution determination requires that a revenue cap/price cap for a future regulatory control period must be set before the end of the current regulatory control period. This means that the actual capex for the final year of the current regulatory control period is not known before the closing RAB is established. This, in turn, means that the DNSPs' opening RAB values, prescribed in clause S6.2.1(c)(1)—which was

179 EnergyAustralia, *Regulatory proposal*, attachment 1.2, distribution RAB roll forward model.
180 EnergyAustralia, *Regulatory proposal*, attachment 1.2, transmission RAB roll forward model.
181 Integral Energy, *Regulatory proposal*, p. 152.
182 Integral Energy, *Regulatory proposal*, p. 158.
183 Integral Energy, *Regulatory proposal*, p. 158.
184 Integral Energy, *Regulatory proposal*, pp. 157–158.

taken from the 2004 IPART determination—is based on estimates of capex in the later part of the previous regulatory control period.

Clause S6.2.1(c)(2) is designed to deal with this situation. It provides that, once the actual capex for the final part of the previous regulatory control period (in the case of the DNSPs, this is the period from 1 July 2003 to 30 June 2004) is known, the opening RAB at 1 July 2004 must be adjusted for the difference between the forecast and actual expenditure.

The AER's RFM makes the adjustments to the opening RAB as required under clause S6.2.1(c)(2).

DNSP proposals

Country Energy

Country Energy's proposed RAB includes a decrease of $5.9 million to take account of lower than estimated capex between July 2003 and June 2004 (the last year of the previous regulatory control period). Further, $3.6 million has been removed which reflects the compounding return on the capex differential.[185]

EnergyAustralia

EnergyAustralia's proposed RAB includes an increase of $26 million to take account of higher than estimated capex for distribution assets between July 2003 and June 2004 (the last year of the previous regulatory control period). Further, $16 million has been added which reflects the compounding return on the capex differential. For EnergyAustralia's transmission network assets, no adjustment is required for the last year of the previous regulatory control period as actual expenditure data was available at the time the ACCC made its 2005 revenue cap decision for EnergyAustralia's transmission network.[186]

Integral Energy

Integral Energy's proposed RAB includes a reduction of $59 million to take account of lower than estimated capex between July 2003 and June 2004 (the last year of the previous regulatory control period). Further, $36 million has been removed which reflects the compounding return on the capex differential.[187]

AER considerations

The AER notes clause S6.2.1(c) of the transitional chapter 6 rules requires that:

- the opening RAB for each of the DNSPs is to be determined by rolling forward the value given to the RAB at a date specified in the table in clause S6.2.1(c)(1)
- the values prescribed in the table are to be adjusted for the difference between actual and forecast capex for any part of a previous regulatory control period
- these adjustments must remove any benefit or penalty on the returns associated with any difference between actual and forecast capex.

185 Country Energy, *Regulatory proposal*, RFM.
186 EnergyAustralia, *Regulatory proposal*, RFM.
187 Integral Energy, *Regulatory proposal*, RFM.

Country Energy

The AER reviewed Country Energy's inputs to the RFM for the previous regulatory control period—1 July 2003 to 30 June 2004—and has cross checked them against Country Energy's regulatory accounts.[188] The AER is satisfied that Country Energy has completed the RFM with inputs that are in accordance with the requirements of the transitional chapter 6 rules, with one exception.[189] While the method used to calculate actual inflation inputs to the RFM for adjusting the opening RAB is consistent with that approved by IPART, the calculated actual inflation input did not correspond to the relevant year. The 2003−04 inflation value was used as an input in 2004−05 instead of 2003−04, the 2004−05 inflation value was used as an input in 2005−06 instead of 2004−03 and so on.

Accordingly, the AER has corrected the inflation input values.

EnergyAustralia

The AER reviewed EnergyAustralia's inputs to the RFM (distribution RAB) for the previous regulatory control period—1 July 2003 to 30 June 2004—and has cross checked them against EnergyAustralia's regulatory accounts.[190]

The AER is generally satisfied that EnergyAustralia has completed the RFM with inputs that are in accordance with the requirements of the transitional chapter 6 rules, with two exceptions:

- EnergyAustralia used a value of 7.0 per cent for the real pre-tax WACC input for 2003−04. IPART determined a real pre-tax WACC of 7.5 per cent.[191] The AER has amended the RFM to reflect the IPART approved real pre-tax WACC of 7.5 per cent for 2003−04.

- The method used to calculate actual inflation inputs to the RFM for adjusting the opening RAB is not consistent with that approved by IPART. The AER has adopted IPART's approved method to calculate actual inflation used for indexation of the control mechanism during the current regulatory control period as required under clause 6.5.1(e)(3), which results in different CPI inputs to the RFM.

Table 5.1 sets out the corrections to EnergyAustralia's RFM in relation to the opening RAB as at 30 June 2004.

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188 This includes the regulatory accounts for Australian Inland Energy where relevant.

189 The AER notes that Country Energy mislabelled the units $ as $ millions in the RFM. The AER has relabelled the RFM as $000 to align the RFM with Country Energy's submission.

190 As discussed previously, no adjustment is required for EnergyAustralia's transmission RAB as actual capex was available at the time the ACCC made its 2005 revenue cap decision for EnergyAustralia.

191 IPART, *Regulation of NSW Electricity Distribution Networks, Determination and Rules under the National Electricity Code*, December 1999, p. 47.

Table 5.1: AER's corrections to EnergyAustralia's proposed distribution RFM

Opening RAB component	Proposed	Approved	Reason
Indexation method	Change in the sum of four quarters to June CPI	Change in the sum of four quarters to December CPI	In accordance with IPART determination
Real pre-tax WACC for 2003–04	7.0 per cent	7.5 per cent	In accordance with IPART determination

Integral Energy

The AER reviewed Integral Energy's inputs to the RFM for the previous regulatory control period—1 July 2003 to 30 June 2004—and has cross checked them against Integral Energy's regulatory accounts. The AER notes that variances were reconciled and explained by the treatment of public lighting and capital contributions within Integral Energy's regulatory accounts. The AER is satisfied that Integral Energy has completed the RFM with inputs that are in accordance with the requirements of the transitional chapter 6 rules, with the exception of two anomalies:

- Similar to Country Energy, the method used by Integral Energy to calculate actual inflation inputs to the RFM for adjusting the opening RAB is consistent with that approved by IPART. The AER has amended the actual inflation input values.

- Integral Energy used values of 2.5 per cent and 10.19 per cent for the forecast inflation and the nominal WACC inputs respectively for 2003−04. However, IPART determined an inflation forecast of 3.0 percent and the nominal WACC is 10.73 per cent (based on a real WACC of 7.5 per cent).[192] The AER has amended the RFM to reflect the IPART approved values for 2003−04.

Table 5.2 sets out the corrections to Integral Energy's RFM in relation to the opening RAB as at 30 June 2004.

Table 5.2: AER's corrections to Integral Energy's proposed distribution RFM

Opening RAB component	Proposed	Approved	Reason
Forecast inflation for 2003–04	2.5 per cent	3.0 per cent	In accordance with IPART determination
Nominal WACC for 2003–04	10.19 per cent	10.73 per cent	Calculated from real pre-tax WACC and forecast inflation as approved by IPART
Indexation method	CPI input out by one year	CPI input moved to relevant year	To align the CPI inputs in the RFM

[192] IPART, *Regulation of NSW Electricity Distribution Networks*, p. 47.

5.4.2 Roll forward methodology and closing asset value June 2009

Under the AER's RFM and based on the transitional chapter 6 rules, the closing RAB (nominal) for each year of the current regulatory control period is calculated by:

- increasing the opening RAB by the amount of capex incurred (including estimated capex for the remaining part of the current regulatory control period) and adjusted for the difference between actual CPI and forecast inflation
- reducing the opening RAB by the amount of regulatory depreciation using the rates and methodologies allowed in the 2004 IPART determination, and adjusted for the difference between actual CPI and forecast inflation
- reducing the opening RAB by the amount of disposal value of any disposed assets.

At the end of the current regulatory control period, as discussed in section 5.4.1, the closing RAB is adjusted for the difference between estimated capex during the previous regulatory control period and actual capex for that part of the period, and the return on the difference.

DNSP proposals

Country Energy

Applying the AER's RFM Country Energy derived an opening RAB as at 1 July 2009 of $4236 million. Country Energy also proposed that $296 million be added to the opening RAB to reflect assets that were omitted from IPART's 1999 asset valuation. This amount was not included in Country Energy's RFM.[193]

EnergyAustralia

Using the AER's RFM (for its distribution and transmission RABs separately) EnergyAustralia has proposed a combined opening RAB for the next regulatory control period of $8218 million as at 1 July 2009.[194] This is comprised of $7229 million for its distribution opening RAB and $989 million for its transmission opening RAB.[195]

Integral Energy

Applying the AER's RFM Integral Energy derived an opening RAB as at 1 July 2009 of $3665 million. Integral Energy also proposed an increase of $170 million for erroneous asset lives in its opening RAB. This value was not included in Integral Energy's RFM.[196] However, Integral Energy adjusted the opening RAB value in the PTRM to include the $170 million adjustment.

AER considerations

Country Energy

As noted in section 5.4.1 the method used by Country Energy to calculate actual inflation inputs to the RFM for adjusting the opening RAB is consistent with that approved by

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193 Country Energy, *Regulatory Proposal,* p. 176.
194 EnergyAustralia, *Regulatory Proposal,* p. 27.
195 EnergyAustralia, *Regulatory Proposal*, attachment 1.1, and attachment 1.2.
196 Integral Energy, *Regulatory Proposal,* p. 157.

IPART, however, the calculated inflation inputs were misaligned by one year and this has also impacted on the CPI inputs to the RFM for the current regulatory control period. The AER has corrected these inputs to align with the relevant years.

The AER notes that Country Energy has included an amount of $112 million in its RAB to reflect the deferral of depreciation allowed for in the 2004 IPART determination as provided for by clause S6.2.1(g) of the transitional chapter 6 rules.[197]

Adjustments to July 2004 RAB

Country Energy proposal

Country Energy has proposed that $296 million ($2008–09) of omitted assets should be added to the value of the 1 July 2004 RAB.[198] Country Energy noted that at the time the 1998 asset valuation was determined a number of material inaccuracies existed. In 2002 NSW Treasury, on behalf of the NSW DNSPs, engaged Sinclair Knight Merz (SKM) to undertake an updated Optimised Depreciated Replacement Cost (ODRC) valuation as at 30 June 2002. SKM concluded that the inaccuracies relating to Country Energy's RAB valuation amounted to $420 million ($1998).[199] Table 5.3 sets out the material inaccuracies in the 1998 asset valuation identified in the SKM report and outlined in Country Energy's proposal.

Table 5.3: Country Energy proposed RAB corrections

Summary of RAB corrections [200]		
Impact	CE estimate from IPART submission ($m, 1998)	SKM estimate ($m, 1998)
Unit Rates	269	151
Omitted Assets – Southern Region and zone substations	229	98
Omitted assets – underground service cables		122
Optimisation of OH lines and rural transformers	18	18
Non–system assets	31	31
Total error in 1998 RAB	547	420

Source: Country Energy, *Regulatory proposal*, p. 180.

Of the $420 million ($1998) of assets identified in the SKM report and outlined above, Country Energy seeks an adjustment for the following categories:

- omitted assets – Southern region and zone substations

197 Country Energy, *Regulatory Proposal,* pp. 156–157.
198 Country Energy, *Regulatory Proposal,* p. 180.
199 Country Energy, *Regulatory Proposal,* pp. 177–178.
200 SKM, *Country Energy Review of Asset Values and IPART Preliminary Analysis Final Report,* 20 October 2003, Table 3-1, p. 4.

- omitted assets – underground service cables.

Country Energy submitted that the value of what it terms ‘the omitted assets’ ($220 million in 1998 dollars) should be included in its RAB in accordance with clause S6.2.1(e)(8) of the transitional chapter 6 rules. The value of these omitted assets is estimated to be $296 million ($2008–09).[201]

The SKM Report classifies the assets comprising the $220 million in the following ways:[202]

- underground service cables of $122 million (comprised of $160 978 000 underground service cables less capital contributions estimated to be $38 957 000)
- substation assets transferred from TransGrid (the SKM report indicates a DORC value in 1998 of $5 349 000)
- zone substations in the southern region being former Great Southern Energy assets (the SKM report indicates a DORC value in 1998 of $1 908 000)
- zone substations in the northern region (the SKM report indicates a DORC value in 1998 of $3 948 000)
- GSE capex of $87 million (1998 dollars).

AER considerations

Clause S6.2.1(c)(1) of the transitional chapter 6 rules includes a table which provides the RAB values for each of the ACT and NSW DNSPs as at 1 July 2004. Clause S6.2.1(c)(2) sets out the method by which the RAB values in the table must be adjusted. Additionally clause S6.2.1(c)(3) provides:

> When rolling forward a regulatory asset base under subparagraph (1), the AER must take into account the derivation of the values in the above table from past regulatory decisions and the consequent fact that they relate only to the regulatory asset base identified in those decisions.

The AER considers that the effect of clause S6.2.1(c) is that the RAB must be rolled forward in accordance with the values that are set out in the table, and that it may only be adjusted in the specific circumstances provided in clause S6.2.1.

Clause S6.2.1(e)(8) of the transitional chapter 6 rules states:

> (e) Method of adjustment of value of regulatory asset base
>
> Except as otherwise provided in paragraph (c), the value of the regulatory asset base for a distribution system as at the beginning of the first regulatory year of a regulatory control period must be calculated by adjusting the value (the ‘previous value’) of the regulatory asset base for that distribution system as at the beginning of the first regulatory year of the immediately preceding regulatory control period (the ‘previous control period’) as follows:

201 Country Energy, *Regulatory proposal*, p. 180.

202 SKM, *Country Energy Final Report,* pp. 15–17.

…..

(8) The previous value of the regulatory asset base may be increased by the value of an asset to which this subparagraph applies to the extent that:

(i) the AER considers the asset to be reasonably required to achieve one or more of the capex objectives; and

(ii) the asset is properly allocated to standard control services in accordance with the principles and policies set out in the Cost Allocation Method for the relevant Distribution Network Service Provider; and

(iii) the value of the asset has not been otherwise recovered.

This subparagraph applies to an asset that:

(i) was not used to provide standard control services (or their equivalent under the previous regulatory system) in the previous regulatory control period but, as a result of a change to the classification of a particular service under Part B, is to be used for that purpose for the relevant regulatory control period; or

(ii) was never previously used to provide standard control services (or their equivalent under the previous regulatory system) but is to be used for that purpose for the relevant regulatory control period.

When referring to this clause, this decision uses the words "first" or "second" to identify whether it is the first or second set of paragraphs denoted with roman numerals.

An adjustment in accordance with this subparagraph is only permitted where either of the second clause S6.2.1(e)(8)(i) or (ii) (referred to in this chapter as the first and second threshold tests) are satisfied. The AER considers that it may only adjust Country Energy's RAB to include the omitted assets if one of the threshold tests set out in these clauses is satisfied.

Second clauses S6.2.1(e)(8)(i) and (ii)

The AER considers that the first threshold test would not be satisfied. For this to be satisfied an asset must not have been used to provide standard control services (or their equivalent) in the current regulatory control period. Country Energy does not submit that these assets are to be 'reclassified' from assets that were not used to provide standard control services in the current regulatory control period, to assets to be used for that purpose. It appears that these assets provided standard control services in the current regulatory control period. While Country Energy notes in its regulatory proposal that the 'omitted assets' have not been formally recognised by IPART as contributing to the RAB value, it has still been required to maintain the assets for the purposes of providing standard control services.[203] Therefore, according to Country Energy's submission, the assets in question are not the subject of a change in classification from the current regulatory control period to the next regulatory control period, and are therefore currently providing standard control services.

[203] Country Energy, *Regulatory proposal*, p. 181.

In relation to the second threshold test , the AER notes that the drafting of the second threshold test is different to the first threshold test in second clause S6.2.1(e)(8)(i). The second clause S6.2.1(e)(8)(ii) states that it applies to an asset which:

> was never previously used to provide standard control services (or their equivalent under the previous regulatory system) but is to be used for that purpose for the relevant regulatory control period.

The AER considers that the second threshold test is intended to apply to assets that have never before provided standard control services.

Country Energy does not submit that these assets have never provided standard control services. The AER notes that Country Energy in its regulatory proposal acknowledges that all of the 'omitted assets' physically exist and form a critical part of its distribution network and are properly required to support the provision of standard control services to current customers.[204] To satisfy the second threshold test, the 'omitted assets' in question would be required to have never provided standard control services. Thus, the AER does not consider the second threshold test is met and therefore no adjustment to the RAB should be made.

Even if a contrary view of clause S6.2.1(e)(8) of the transitional chapter 6 rules was taken and it was determined that either of the threshold tests in second clauses S6.2.1(e)(8)(i) and (ii) were satisfied, the relevant assets would also have to satisfy the first three criteria set out in the first clauses S6.2.1(e)(8)(i), (ii) and (iii).

First clauses S6.2.1(e)(8)(i), (ii) and (iii)

The AER notes Country Energy's arguments to demonstrate that the omitted assets meet the three criteria in the first clauses S6.2.1(e)(8)(i), (ii) and (iii) of the transitional chapter 6 rules and makes the following comments.

Underground cables

The AER notes that the SKM report stated that the underground cables were not included in the 1998 valuation as they had been funded by capital contributions from customers. While the 2002 SKM report includes a capital contribution as a component of its asset valuation, the report notes that when the cables were constructed they were fully funded by customer contributions. The Steering Committee for the 2002 valuation took the view that the underground cables should be included in the distributors' asset register given that 'the maintenance of these services were provided for within the distributors' operational maintenance expenditure.[205] This view concerns the AER as it is inconsistent with the regulatory framework. While a DNSP is able to receive revenues to cover its opex arising from the maintenance of capital contributed assets, it is not entitled to recover both returns on and of capital for such assets as they have already been compensated through capital contributions made by customers.[206] The AER considers the exclusion of such assets from the RAB valuation as occurred in 1998 is consistent with the regulatory framework. As the value of the underground cables have otherwise been recovered, the first clause S6.2.1(e)(8)(iii) would not be met and therefore no adjustment to the Country Energy's RAB is warranted.

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[204] Country Energy, *Regulatory proposal*, p. 180.
[205] SKM, *Country Energy Final Report,* p. 21.
[206] Transitional chapter 6 rules, clause 6.21.2(1).

Region and zone substations

In respect of the zone and region substation assets, there appears to be substation assets identified by SKM that were transferred from TransGrid to the former entity known as Great Southern Energy as well as assets of both Great Southern Energy and the former entity known as NorthPower which were omitted from Country Energy's RAB. The assets identified by SKM include:

- assets transferred from TransGrid (the SKM report indicates a DORC value in 1998 of $5349 000)[207]
- former Great Southern Energy assets (the SKM report indicates a DORC value in 1998 of $1908 000)[208]
- former NorthPower assets (the SKM report indicates a DORC value in 1998 of $3948 000).[209]

The AER notes these values would need to be appropriately verified as the relevant asset value for consideration of inclusion in the opening RAB.

The AER further notes that the assets that were not on the asset register of Great Southern Energy were considered in the 2004 IPART draft decision as part of the pool of unrecognised assets.[210]

Even in light of IPART's consideration of these issues it may be appropriate to reflect on inclusion of these assets at a relevant regulatory value, if permitted by the transitional chapter 6 rules.

In the information provided about the age profile of the 'omitted assets' provided in the SKM report, the zone substations in the southern region are shown to have commissioning dates of between 1958 and 1998 as at the 1998 valuation date. This infers that based on a standard asset life of 40.2 years as provided in the Country Energy RFM some of these assets without any augmentations to extend asset lives would be fully depreciated on a straight-line basis.

Similarly the zone substations in the northern region have commissioning dates of between 1965 and 1990. These assets are aged between 18 to 40 years. The AER would expect that the Lismore substation which was commissioned in 1968 and comprises the largest value for the substation assets in the northern region would be close to fully depreciated on a straight-line basis.[211] The AER notes that the SKM report does not provide the level of detail about commissioned dates of assets transferred from TransGrid and it may well be the case that the value of these assets are also fully depreciated.[212]

In contemplating inclusion of these assets the AER would need to be satisfied that the valuation of the assets is consistent with the valuation methodology for other assets that

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207 SKM, *Country Energy Final Report*, p. 15.
208 SKM, *Country Energy Final Report*, p. 16.
209 SKM, *Country Energy Final Report*, p. 17.
210 SKM, *Country Energy Final Report*, p. 196.
211 SKM, *Country Energy Final Report*, pp. 16–17.
212 SKM, *Country Energy Final Report*, p. 15–17.

comprise the RAB and these values are appropriately adjusted for inflation, capex incurred, disposals and actual depreciation over time from the time of transfer as is relevant to other assets that comprise the RAB.

As described above the AER considers that these assets would not meet the first or second threshold tests in second clauses S.6.2.1(e)(8)(i) and (ii) of the transitional chapter 6 rules and therefore no adjustment could be made to the RAB to include these 'omitted assets'. Even if a threshold test was satisfied the AER notes that clause S6.2.1(f) requires an adjustment to the RAB value under clause S6.2.1(e)(8) is to be based on the value of the relevant assets as shown in independently audited and published accounts. The AER considers it is unlikely to be able to determine a value based on audited and published accounts.

Great Southern Energy capital expenditure

According to the SKM report there were a number of assets that were constructed by the former Great Southern Energy during the period 1995–1998 that were not included in the 1998 RAB valuation.[213] Country Energy submitted that in order for the opening RAB at 1 July 2009 to be accurate before a RFM can be applied an adjustment to recognise the omission of these assets from the 1998 RAB valuation should be made. Country Energy considers that an appropriate value for these assets ($87 million in $1998) should be the capex acknowledged by the IPART Section 12A report.[214]

The AEr has reviewed SKM's report and considers that the claim for omitted assets is in effect a claim for a revaluation of capex, based on estimation.[215] Clause S6.2.1(c)(2) of the transitional chapter 6 rules only permits an adjustment to the value prescribed in clause S6.2.1(c)(1) to account for differences in the actual and estimated capex that is included in those values for any part of the previous regulatory control period. It does not permit a revaluation of existing assets to account for capex from periods prior to the previous regulatory control period.

Further, the AER considers that these assets would not meet either of the threshold tests in second clauses S.6.2.1(e)(8)(i) and (ii) of the transitional chapter 6 rules and therefore no adjustment could be made to the RAB to include an adjustment for changes in the value of capex. Even if a threshold test was satisfied the AER notes that clause S6.2.1(f) requires an adjustment to the RAB value under clause S6.2.1(e)(8) is to be based on the value of the relevant assets as shown in independently audited and published accounts. The AER considers it is unlikely to be able to determine a value based on audited and published accounts.

Other comments

The AER notes that IPART considered an almost identical proposal relating to 'omitted assets' by Country Energy as part of its 2004 regulatory determination and did not accept the proposal. IPART noted that Country Energy's 1998 RAB was established taking

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213 SKM, *Country Energy Final Report,* p. 19.
214 Country Energy, *Regulatory proposal*, p. 179.
215 SKM, *Country Energy Final Report*, p. 21; and
Country Energy, *Regulatory proposal*, pp. 176–180, especially p.178.

account of an optimal deprival valuation methodology but that this was not the sole determinant of the RAB. IPART characterised its RAB valuation as a financial value:[216]

> In deciding how to calculate the opening RAB, the Tribunal's key consideration was the fact that has taken a financial view of the RAB in the past. That is, a DNSP's RAB has been taken to represent the shareholder's financial investment in the business.
>
> This financial view means that, on a forward looking basis, in providing a return on and of the RAB, the Tribunal seeks to maintain the shareholder's financial investment in real terms. It also means that, once the financial value of the RAB is struck, the RAB is effectively detached from the underlying physical assets. Changes in the replacement costs of assets, service lives and methodologies for optimisation do not affect the value of the RAB (except that they might affect the profile of depreciation over time). Changes in these values do not require a re-valuation of the RAB.
>
> The Tribunal's draft decision to roll forward the RAB without making any adjustments to the 1998 RAB is consistent with this financial view.

The AER understands this expression to mean that the value of the RAB is not based on a value derived by summing the value of the DNSP's assets (a bottom up valuation). Rather it is a value that balances a number of considerations, including the ability of users to accommodate price shocks. This 'top down' valuation is then allocated to assets listed in a DNSP's asset register.

The AER does not accept Country Energy's view of IPART's 2004 determination. The AER considers IPART did not approve Country Energy's submission about proposed corrections to the 1998 RAB for 'omitted assets' as it was not satisfied that it was necessary to adjust the 1998 RAB to take account of these 'missing assets'. IPART established the RAB on the basis of a financial valuation.[217] The AER considers that the National Electricity Code operating at that time provided IPART with the discretion to determine Country Energy's RAB as a financial valuation.

Conclusion – Country Energy adjustments to July 2004 RAB

In conclusion, the transitional chapter 6 rules do not provide for Country Energy's submission to increase its RAB for 'omitted assets' as the threshold tests in second clause S6.2.1(e)(8)(i) and (ii) have not been met and therefore the AER does not approve Country Energy's proposal to increase the opening value of the RAB by $296 million.

EnergyAustralia

Distribution RAB

As noted in section 5.4.1 EnergyAustralia did not apply IPART's indexation method and this has also impacted on the CPI inputs to the RFM for the current regulatory control period. The AER has corrected these inputs to reflect the IPART indexation method. Based on these updated CPI inputs and the corrections for the anomalies identified in section 5.4.1 the AER has determined EnergyAustralia's distribution opening RAB to be $7203 million for the next regulatory control period (as at 1 July 2009).

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216 IPART, *Draft Report Regulation of NSW Electricity Distribution Networks,* January 2004, p. 197.
217 IPART, *Regulation of NSW Electricity Distribution Networks,* pp. 47–49.

Transmission RAB

In reviewing the submitted RFM for EnergyAustralia's transmission RAB, the AER is generally satisfied that EnergyAustralia has completed the RFM with appropriate inputs, with two exceptions:

- EnergyAustralia used a value of 8.92 per cent for the nominal vanilla WACC input for the current regulatory control period. However, the AER determined a nominal vanilla WACC of 9.08 per cent following its revocation and substitution of EnergyAustralia's revenue cap in December 2007. The AER has therefore amended the RFM to appropriately reflect the AER approved nominal vanilla WACC.[218]

- Similar to its distribution RAB actual inflation inputs to the RFM, the method used to calculate actual inflation inputs to the RFM for adjusting the transmission opening RAB is not consistent with that used for indexation of the maximum allowed revenue during the current regulatory control period as required under clause 6A.6.1(e)(3). The AER has therefore amended the RFM to reflect the appropriate CPI inputs, which are also consistent with those applied by TransGrid for its asset roll forward during the current regulatory control period.

Table 5.4 sets out the corrections to EnergyAustralia's RFM in relation to its opening RAB for its transmission network. Based on these corrections the AER has determined EnergyAustralia's transmission opening RAB to be $985 million for the next regulatory control period (as at 1 July 2009).

Table 5.4: AER's corrections to EnergyAustralia's proposed transmission RFM

Opening RAB component	Proposed	Approved	Reason
Indexation method	June-on-June quarter change in CPI	March-on-March quarter change in CPI	In accordance with indexation of the maximum allowed revenue during current regulatory control period
Nominal vanilla WACC for current regulatory control period	8.92 per cent	9.08 per cent	In accordance with the AER substituted determination of December 2007

Integral Energy

As noted in section 5.4.1 the method used by Integral Energy to calculate actual inflation inputs to the RFM for adjusting the opening RAB is consistent with that approved by IPART, however, the calculated inflation inputs were misaligned by one year and this has also impacted on the CPI inputs to the RFM for the current regulatory control period. The AER has corrected these inputs to align with the relevant years.

[218] AER, *Application by EnergyAustralia to re-open its 2004/05 – 2008/09 revenue cap, Decision*, 21 December 2007.

Adjustments to July 2004 RAB

Integral Energy proposal

Integral Energy sought to increase its opening RAB at 1 July 2009 by $170 million. The basis for the adjustment is to provide a lump sum increase in the RAB for an error in the asset lives of sub–transmission and zone substations. This was based on an SKM ODRC valuation undertaken in 2002.[219]

Integral Energy submitted that clause S6.2.1(e)(8) of the transitional chapter 6 rules provides the AER with discretion to increase the previous value of the RAB as determined by IPART.

AER considerations

Clause S6.2.1(c)(1) of the transitional chapter 6 rules includes a table which provides the RAB values for each of the ACT and NSW DNSPs as at 1 July 2004. Clause S6.2.1(c)(2) sets out the method by which the RAB values in the table must be adjusted. Additionally clause S6.2.1(c)(3) provides:

> When rolling forward a regulatory asset base under subparagraph (1), the AER must take into account the derivation of the values in the above table from past regulatory decisions and the consequent fact that they relate only to the regulatory asset base identified in those decisions.

Clause S6.2.1(e)(8) states:

> (e) Method of adjustment of value of regulatory asset base
>
> Except as otherwise provided in paragraph (c), the value of the regulatory asset base for a distribution system as at the beginning of the first regulatory year of a regulatory control period must be calculated by adjusting the value (the 'previous value') of the regulatory asset base for that distribution system as at the beginning of the first regulatory year of the immediately preceding regulatory control period (the 'previous control period') as follows:
>
> …..
>
> (8) The previous value of the regulatory asset base may be increased by the value of an asset to which this subparagraph applies to the extent that:
>
> > (i) the AER considers the asset to be reasonably required to achieve one or more of the capital expenditure objectives; and
> >
> > (ii) the asset is properly allocated to standard control services in accordance with the principles and policies set out in the Cost Allocation Method for the relevant Distribution Network Service Provider; and
> >
> > (iii) the value of the asset has not been otherwise recovered.
> >
> > This subparagraph applies to an asset that:
> >
> > (i) was not used to provide standard control services (or their equivalent under the previous regulatory system) in the previous regulatory control period but, as a result of a change to the classification of a particular service

[219] Integral Energy, *Regulatory proposal,* p. 157.

under Part B, is to be used for that purpose for the relevant regulatory control period; or

(ii) was never previously used to provide standard control services (or their equivalent under the previous regulatory system) but is to be used for that purpose for the relevant regulatory control period.

The AER considers that in order for it to adjust Integral Energy's RAB to include a lump sum increase in the RAB for an error in the asset lives of sub–transmission and zone substations as proposed by Integral Energy either the first or second threshold test set out in second clauses S6.2.1(e)(8)(i) and (ii) of the transitional chapter 6 rules must be satisfied.

The AER considers that for the first threshold test to be met, the assets to which the test is being applied must be involved in the provision of a service which is the subject of a change in classification, that is, from assets that were not used to provide standard control services in the current regulatory control period to assets to be used for that purpose. The AER does not consider this threshold test has been met. First, the assets to which the error in asset lives relates are providing standard control services. Second, the error in the asset lives could not be characterised as a reclassification of a service. Accordingly, the AER does not consider the first threshold test is met.

As noted previously, the AER considers that the second threshold test is intended to apply to assets that never previously provided standard control services.

The AER does not consider the second threshold test would be satisfied as the assets to which the error in asset lives relates, as previously described, appear to be providing standard control services and therefore it could not be said the assets have never provided standard control services. To satisfy the second threshold test, the error in asset lives would have to relate to assets that have never provided standard control services. The AER does not consider this to be the case. Accordingly, the AER does not consider that the second threshold test is met.

Even if a contrary view of clause S6.2.1(e)(8) of the transitional chapter 6 rules was taken and it was determined that either of the threshold tests in the second clauses S6.2.1(e)(8)(i) and (ii) were satisfied, the relevant assets would also have to satisfy the first three criteria set out in first clauses S6.2.1(e)(8)(i), (ii) and (iii).

Further, the AER notes that clause S6.2.1(f) of the transitional chapter 6 rules requires an adjustment to the RAB value under clause S6.2.1(e)(8) is to be based on the value of the relevant assets as shown in independently audited and published accounts.

As noted previously the AER considers that clause S6.2.1(c) of the transitional chapter 6 rules when read with the other provisions relating to the determination of the RAB requires the AER to roll forward the values that are set out in the table and not, except where the specific exceptions apply, to re-open the RAB or fix any alleged errors made by IPART.

The AER notes that IPART considered a proposal relating to errors in asset lives by Integral Energy as part of its 2004 regulatory determination and did not accept the proposal. IPART noted that Integral Energy's 1998 RAB was established taking account of an optimal deprival valuation methodology but that this was not the sole determinant of the RAB. IPART characterised its RAB valuation as a financial value.

As noted in the AER's considerations relating to Country Energy's proposal to include 'omitted assets', the AER is satisfied that given the National Electricity Code operating at that time, IPART was able to determine Integral Energy's RAB as a financial valuation.

Conclusion – Integral Energy adjustments to July 2004 RAB
In conclusion, the transitional chapter 6 rules do not provide for Integral Energy's submission to increase its RAB for errors in asset lives as the threshold tests in second clause S6.2.1(e)(8)(i) and (ii) have not been met. Therefore the AER has decided to reject Integral Energy's proposal to add $170 million to its RAB.

Conclusion – Roll forward methodology and closing asset value June 2009

Country Energy

Based on the updated CPI inputs (including the correction discussed in section 5.4.1) the AER has determined Country Energy's opening RAB to be $4247 million for the next regulatory control period (as at 1 July 2009). This value is used as an input for the AER's PTRM for the purposes of determining Country Energy's weighted average price cap during the next regulatory control period.

EnergyAustralia

Based on these updated WACC and CPI inputs the AER has determined EnergyAustralia's distribution and transmission opening RABs to be $7203 million and $985 million respectively for the next regulatory control period (as at 1 July 2009). These values are used as inputs for the AER's PTRM for the purposes of determining EnergyAustralia's weighted average price cap (distribution) and maximum allowed revenue (transmission) during the next regulatory control period.

Total RAB
The AER has determined a total opening RAB for EnergyAustralia of $8188 million for the next regulatory control period (as at 1 July 2009).

Integral Energy

Based on the updated CPI inputs and the corrections for the anomalies identified in section 5.4.1 the AER has determined Integral Energy's opening RAB to be $3678 million for the next regulatory control period (as at 1 July 2009). This value is used as an input for the AER's PTRM for the purposes of determining Integral Energy's weighted average price cap during the next regulatory control period.

5.4.3 RAB roll forward for the next regulatory control period.

Clause 6.12.1(18) of the transitional chapter 6 rules requires the AER to determine whether the depreciation for establishing the opening RAB for the following regulatory control period (i.e. as at 1 July 2014), is to be based on actual or forecast capex (referred to here as the use of 'actual' or 'forecast' depreciation). This contrasts to the requirement of the transitional provision in schedule 6.2.1(e)(5) which requires the use of actual depreciation when rolling forward the RAB for the current regulatory control period.

The use of actual or forecast depreciation relates to whether the return of capital forms part of the capex incentive framework. For example, in the case of an overspend in capex, under the actual depreciation framework, the opening RAB would be reduced by a higher amount of depreciation (reflecting the higher capex) than if forecast depreciation was applied. In this case, the DNSP loses the return on the capital in excess of the capex allowance and incurs faster depreciation of its RAB. The situation is reversed for capex underspends where the reward is potentially higher.

5.4.3.1 DNSP proposals

EnergyAustralia proposed the use of forecast depreciation as it provides a lower powered incentive, which it argues is appropriate because:

> There are significant uncertainties that EnergyAustralia must face during the regulatory control period (cost escalation, resourcing etc) that would warrant a lower power methodology.[220]

In this situation, EnergyAustralia considers that the scope for windfall gains and losses is increased under a stronger incentive framework, and therefore a lower powered mechanism is one that is that is more likely to promote economic efficiency in accordance with section 7A of the NEL.

5.4.3.2 AER considerations

The AER notes that the NER does not offer any criteria regarding its decision on the use of actual or forecast depreciation, or on the capex incentive framework generally. Section 7A(3) of the NEL provides general guidance with respect to incentives:

> A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes—
>
> (a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
>
> (b) the efficient provision of electricity network services; and
>
> (c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

EnergyAustralia’s general comment regarding the significant uncertainties it must face i.e. ‘cost escalation, resourcing etc’, implies a risk that its expenditures will diverge significantly from those it has proposed due to uncontrollable and unforeseen factors.[221] The AER considers that EnergyAustralia and the other NSW DNSPs have appropriately identified investment drivers for the next regulatory control period and, with few exceptions, have proposed a scope and cost of work that is commensurate with their investment needs. The proposals are also supported by appropriate resourcing and delivery strategies. As noted in section 7.4 the DNSPs have identified the major sources of significant variances from expenditure allowances set for the current regulatory control period, including expected changes in cost escalation, which have been updated by the AER using the most recent market data. For these reasons the AER considers that any uncontrollable variances between actual costs and those accounted for in this

[220] EnergyAustralia, *Regulatory proposal*, p. 156.
[221] EnergyAustralia, *Regulatory proposal*, p. 156.

determination should be minimised, and the resulting risk of windfall gains and losses should be no more than those experienced by a competitive (i.e. efficient) business.

The AER finally notes the general concern expressed by stakeholders on the significant rise in the DNSPs' capex proposals from their current historical levels. In this context the AER considers it important to provide effective incentives for the DNSPs to seek out efficiencies wherever possible throughout their program, and that a high powered incentive is therefore appropriate. The AER's draft decision is to therefore use actual depreciation to establish the opening RAB for the 2014–19 regulatory control period.

5.5 AER conclusion

Country Energy

The RAB roll forward calculations for Country Energy are set out in table 5.5 and provide for an opening RAB of $4247 million for the next regulatory control period (as at 1 July 2009).

Table 5.5: Country Energy's opening RAB for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	2439.0	2638.4	2920.0	3323.8	3724.8
Actual net capex (adjusted for actual CPI and WACC)[c]	276.7	366.7	473.2	522.6	645.1
CPI adjustment on opening RAB	57.2	70.4	103.3	77.5	111.7
Straight-line depreciation (adjusted for actual CPI)	–134.5	–155.6	–172.7	–199.2	–225.0
Closing RAB	2638.4	2920.0	3323.8	3724.8	4256.6
Less: difference between actual and forecast capex for 2003–04					5.7
Less: return on difference[d]					3.5
Opening RAB at 1 July 2009					4247.5

(a) Based on estimated net capex.
(b) Based on forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.
(c) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The cash values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $5.7 million for 1 July 2003 to 30 June 2004.

The AER has decided that the opening RAB should not include omitted assets as proposed by Country Energy. Accordingly, the proposed addition of $296 million is not included in the opening RAB as at 1 July 2009. The AER will update the roll forward of Country Energy's RAB with actual capex for 2007–08 and the most recent forecast of capex for 2008–09, and the latest actual CPI data at a time closer to its final distribution determination.

EnergyAustralia

The RAB roll forward calculations for EnergyAustralia are set out in tables 5.6 and 5.7, and provide for a distribution opening RAB of $7203 million and a transmission opening RAB of $985 million for the next regulatory control period (as at 1 July 2009). The combined distribution and transmission opening RAB as at 1 July 2009 is $8188 million. The AER will update the roll forward of EnergyAustralia's RAB with actual capex for 2007–08 and the most recent forecast of capex for 2008–09, and the latest actual CPI data at a time closer to its final distribution determination.

Table 5.6: EnergyAustralia's revised opening RAB (distribution) for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	4064.0	4428.2	4914.6	5625.0	6368.1
Actual net capex (adjusted for actual CPI and WACC)[c]	432.7	549.9	740.5	846.4	927.2
CPI adjustment on opening RAB	95.2	118.2	173.9	131.2	177.4
Straight-line depreciation (adjusted for actual CPI)	–163.8	–181.7	–204.1	–234.4	–271.0
Closing RAB	4428.2	4914.6	5625.0	6368.1	7201.8
Add: difference between actual and forecast capex for 2003–04					26.7
Add: return on difference[d]					16.1
Less: system assets moving from distribution to transmission					57.2
Add: non–system asset re-allocation					15.4
Opening RAB at 1 July 2009					7202.8

(a) Based on estimated net capex.
(b) Based on estimated net capex and forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.
(c) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The cash values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $26.7 million for 1 July 2003 to 30 June 2004.

Table 5.7: EnergyAustralia's opening RAB (transmission) for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	635.6	663.0	698.9	725.7	777.9
Actual net capex (adjusted for actual CPI and WACC)[c]	39.0	44.7	40.8	54.5	169.0
CPI adjustment on opening RAB	15.0	19.8	17.0	30.8	33.0
Straight-line depreciation (adjusted for actual CPI)	–26.7	–28.6	–31.0	–33.1	–36.9
Closing RAB	663.0	698.9	725.7	777.9	943.0
Add: system assets moving to transmission from distribution					57.2
Less: non–system asset re-allocation					15.4
Opening RAB at 1 July 2009					984.8

(a) Based on estimated net capex.
(b) Based on estimated net capex and forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.
(c) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The accounting book values for disposal of assets have been deducted.

Integral Energy

The RAB roll forward calculations for Integral Energy are set out in table 5.8 and provide for an opening RAB of $3678 million for the next regulatory control period (as at 1 July 2009).

Table 5.8: Integral Energy's opening RAB for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	2283.5	2454.1	2706.5	3019.7	3317.0
Actual net capex (adjusted for actual CPI and WACC)[c]	248.5	330.0	376.1	404.3	552.0
CPI adjustment on opening RAB	53.5	65.5	95.8	70.4	99.5
Straight-line depreciation (adjusted for actual CPI)	–131.3	–143.2	–158.7	–177.4	–196.4
Closing RAB	2454.1	2706.5	3019.7	3317.0	3772.2
Less: difference between actual and forecast capex for 2003–04					58.6
Less: return on difference[d]					35.7
Opening RAB at 1 July 2009					3677.8

(a) Based on estimated next capex.
(b) Based on estimated forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.
(c) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The accounting book values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $58.6 million for 1 July 2003 to 30 June 2004.

The AER has decided not to approve Integral Energy's proposed increase to the opening RAB of $170 million to correct erroneous asset lives used in the historical valuation of sub–transmission and zone substations. The AER will update the roll forward of Integral Energy's RAB with actual capex for 2007–08 and the most recent forecast of capex for 2008–09, and the latest actual CPI data at a time closer to its final distribution determination.

5.6 AER draft decision

In accordance with clause 6.12.1(6) of the transitional chapter 6 rules the AER has decided that the opening regulatory asset base at 1 July 2009 for Country Energy is set out in table 5.5 of the draft decision

In accordance with clause 6.12.1(6) of the transitional chapter 6 rules the AER has decided that the distribution opening regulatory asset base at 1 July 2009 for EnergyAustralia is set out in table 5.6 of the draft decision.

In accordance with clause 6.12.1(6) of the transitional chapter 6 rules the AER has decided that the transmission opening regulatory asset base at 1 July 2009 for EnergyAustralia is as set out in table 5.7 of the draft decision.

In accordance with clause 6.12.1(6) of the transitional chapter 6 rules the AER has decided that the opening regulatory asset base at 1 July 2009 for Integral Energy is set out in table 5.8 of the draft decision

In accordance with clause 6.12.1(18) of the transitional chapter 6 rules the AER has decided to use actual depreciation for establishing the regulatory asset base for the commencement of the 2014–19 regulatory control period.

6 Demand forecasts

This chapter discusses the AER's consideration of whether the NSW DNSPs' maximum demand forecasts reflect a reasonable expectation of the demand for standard control services over the next regulatory control period. The AER also considers the extent to which the forecasts can be relied upon for the purposes of assessing the proposed load driven capex. It also discusses the AER's considerations on whether the NSW DNSPs' energy forecasts are appropriate inputs into the AER's PTRM.

6.1 Regulatory requirements

The transitional chapter 6 rules require DNSPs to provide a realistic expectation of the maximum demand forecast as part of addressing the capex and opex objectives and criteria under clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3). The transitional chapter 6 rules also require the AER, as part of its draft distribution determination, to make a decision on appropriate amounts, values or inputs, under clause 6.12.1(10). Appropriate energy consumption and customer number forecasts are necessary inputs into the AER's post tax revenue model (PTRM).

The AER's assessment of the NSW DNSPs' demand forecasts is focussed on the expected summer and winter maximum (or peak) demands, energy sales and customer numbers over the next regulatory control period. Maximum demand (MW or MVA) is the highest level of network capacity sought at a single point in time, and is a key driver of load driven capex requirements. Energy forecasts (GWh) are used to determine the amount of electricity transported over a period of time, and to convert building block revenues to prices in the post tax revenue model. Energy forecasts are also a key input into determining X factors under weighted average price cap regulation.[222] Customer number forecasts are an important input into maximum demand and energy forecasts, and are used in determining weighted average price caps and average price caps.[223]

6.2 NSW DNSPs' proposals

6.2.1 Country Energy

Country Energy based its load driven capex forecasts on maximum demand at 50 per cent probability of exceedence (POE).[224] For the first year of the next regulatory control period, maximum demand in Country Energy's network as a whole is expected to occur in winter. However, Country Energy has forecast its network to transition from winter to summer peaking in 2010–11.[225] This is shown in table 6.1.

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[222] This is because the AER must take the notional building block requirement and convert this into a weighted average price cap or average price cap based on energy growth forecasts.

[223] The AER notes that a number of source materials relied upon in this chapter of the draft decision are confidential, however the AER received confirmation from Country Energy, EnergyAustralia and Integral Energy on 17 November 2008 that the chapter contains no information that is confidential.

[224] Summer maximum demand specified at a 50 per cent POE means that the probability of this maximum demand being exceeded is 50 per cent, or on average one year in two.
Country Energy, *Regulatory proposal*, p. 92.

[225] Country Energy, *Regulatory proposal*, RIN, confidential, table 2.3.8.

Table 6.1: Country Energy's energy and maximum demand forecasts 2009–10 to 2013–14[a]

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14
Energy sales (base) - MWh	12506800	12768530	13019560	13151620	13291920	1.6%
Winter maximum demand (50% POE) - MW	2405	2461	2515	2551	2589	1.8%
Summer maximum demand (50% POE) – MW	2404	2484	2583	2653	2728	3.0%

Source: Country Energy, regulatory proformas, confidential, table 2.3.8.
(a) Shaded values represent system maximum demand for that year.

Country Energy stated that it developed its expenditure forecasts for augmentation projects on sub–transmission powerlines, zone substations and at some high level distribution feeders using a bottom–up approach.[226] Expenditure at the distribution network level was assessed using a top–down approach on the basis of the projected rate of growth in customer connections, historical expenditures and average replacement costs per asset class.[227]

Country Energy engaged the National Institute of Economic and Industry Research (NIEIR) to develop its maximum demand, energy and customer number forecasts.[228] Country Energy stated that NIEIR was responsible for preparing the top–down growth forecasts for its network region over the next regulatory control period, and for researching and giving advice on the forecasts of key economic parameters that may influence electricity demand.[229] Country Energy stated that it carried out further analysis of NIEIR's projections to develop its final winter maximum demand forecast.[230] NIEIR's final report, completed in November 2007, was provided as an attachment to Country Energy's regulatory proposal.[231]

6.2.1.1 Review of past forecasts

Over the current regulatory control period to date, energy consumption on Country Energy's network has grown at an average annual rate of 2.1 per cent, which is higher than the IPART approved forecast of 1.7 per cent per annum.[232] The AER understands that the energy forecast approved by IPART in 2004 has underestimated energy sales by 4 per cent in total over the period 2004–05 to 2006–07.[233]

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226 Bottom–up forecasting is also known as spatial forecasting, or zone substation level forecasting. Country Energy, *Regulatory proposal*, p. 91.
227 Country Energy, *Regulatory proposal*, p. 91.
228 Country Energy, *Regulatory proposal*, p. 84.
229 Country Energy, *Regulatory proposal*, p. 84.
230 Country Energy, *Regulatory proposal*, p. 84. Country Energy provided additional information to the AER on 14 July 2008, outlining changes it made to NIEIR's winter maximum demand forecast to update the forecast to account for recently available winter peak demand data.
231 NIEIR, *Electricity Forecasts for the Country Energy Region to 2018*, Victoria, November 2007.
232 IPART, *NSW Distribution Pricing 2004–05 to 2008–09 Final Report*, p. 28.
233 Country Energy, *Regulatory proposal*, RIN proforma 2.3.8.

Country Energy's network is historically winter peaking. Over the current regulatory control period to date, winter maximum demand grew at an average annual rate of 1.5 per cent.[234]

Country Energy is expected to transition to a summer peaking network over the next regulatory control period. Summer maximum demand has grown at an average annual rate of 2.6 per cent over the current regulatory control period to date, however for regulatory years 2002–03 to 2006–07 the average annual growth rate was 5.6 per cent. In its 2004 final decision, IPART approved forecast average annual growth in maximum demand on Country Energy's network of 2.8 per cent.[235]

Customer numbers have grown by an average annual rate of 0.5 per cent over the period 2004–05 to 2006–07, which is significantly lower than the 2004 forecast approved by IPART of 2 per cent.[236]

Table 6.2 contains the IPART approved forecasts and current regulatory control period data to date.

Table 6.2: Country Energy current regulatory control period – forecasts and actuals*

	2004–05	2005–06	2006–07
Energy sales (base) – MWh 2004 IPART approved forecast	11071000	11269000	11455000
Energy sales (base) – MWh actuals	11407784	11964840	11974120
Difference	3.0%	6.2%	4.5%
System maximum demand (50% POE) – MW – 2004 IPART approved forecast[a]	2097	2154	2205
System maximum demand (50% POE) – MW – actuals[b]	2116	2330	2251
Difference	0.9%	3.5%	2.1%

Source: Country Energy, Regulatory proformas, confidential, table 2.3.8.
(a) Actuals are not weather corrected.
(b) All maximum demand values are for winter.

6.2.1.2 Methodology

Country Energy outlined NIEIR's top–down forecasting approach as:[237]

- using the NEMMCO NSW demand forecasts as a starting point
- projecting historical trends in energy sales into the future using time series models

[234] Country Energy, *Regulatory proposal*, RIN proforma 2.3.8
[235] IPART, *NSW Distribution Pricing 2004–05 to 2008–09 Final Report*, p. 28.
[236] Country Energy, *Regulatory proposal*, RIN proforma 2.3.8.
[237] Top–down forecasts are also known as econometric, or network level forecasts. Country Energy, *Regulatory proposal*, Appendix F, *p. 2*.

- using regression models, determine relationships between electricity sales and economic and demographic variables and other key drivers of demand.

Energy forecasts

NIEIR developed energy forecasts for each county council area by expanding its existing regional based residential forecast model to cover all customer classes, and linking these regional forecasts to individual county council areas.[238] Each county council area was then assigned to a relevant local government area, and sales by customer class were projected forward using NSW electricity regression equations for residential, business and public lighting sales.[239] Business sales were linked to gross regional product forecasts, while residential sales were linked to customer numbers, real income growth and real prices. Public lighting sales were linked to population growth.[240]

Maximum demand forecasts

The key stages in NIEIR's maximum demand forecast methodology were:[241]

- extracting the peak non–coincident demands for each season by county council area and the corresponding ambient temperatures
- calculating POE at the 10th, 50th and 90th percentiles for each Bureau of Meteorology weather recording station in the Country Energy region
- determining the temperature sensitivity of Country Energy county council areas by season
- specifying an equation for each county council's maximum demand.

NIEIR developed a winter and summer maximum demand for the total Country Energy region. The summer equation took into account the growth in air conditioning stock in Country Energy's region.[242]

6.2.1.3 Customer numbers

NIEIR forecast Country Energy's customer numbers based on projections of dwelling construction, recorded historical growth rates and expected economic activity.[243] New electricity customer connections were forecast to grow by 1.46 per cent per annum over the next regulatory control period.[244]

6.2.2 EnergyAustralia

EnergyAustralia forecast peak demand on its network over the next regulatory control period using global (at network level, or top–down), and spatial (at each zone and subtransmission substation, or bottom–up) forecasts.[245] The global peak demand forecasts

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238 NIEIR, p. 25.
239 NIEIR, p. 25.
240 NIEIR, p. 25.
241 NIEIR, p. 30.
242 NIEIR, p. 30.
243 Country Energy, *Regulatory proposal*, p. 50.
244 Country Energy, *Regulatory proposal*, p. 84.
245 EnergyAustralia, *Regulatory proposal,* p. 43.

were used as a check of the reasonableness of the peak demand forecasts implicit in the spatial forecasts.[246]

Under 50 per cent POE weather conditions, EnergyAustralia's network is summer peaking. Its energy and maximum demand forecasts are provided in table 6.3.

Table 6.3: EnergyAustralia's energy and maximum demand forecasts 2009–10 to 2013–14

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14
Energy sales (base) - MWh	28466305	28985908	29455415	29736470	30136072	1.6%
System maximum demand (50% POE) – MW[a]	6205	6378	6550	6722	6894	2.8%

Source: EnergyAustralia, Regulatory proposal, RIN proforma, confidential, table 2.3.8.
(a) All values are for summer peak demand.

6.2.2.1 Key drivers

EnergyAustralia identified the following key drivers of maximum demand and energy consumption on its network:

- growth in customer numbers, which is directly impacted by population growth, household construction and building cycles within the network region
- residential customer characteristics, including trends in household size, type, fuel substitution, efficiency and conservation impacts associated with energy efficiency and greenhouse gas policies
- non-residential customer demand drivers, such as economic growth
- weather
- day types, in particular leap years
- real electricity prices and gas price relativity.[247]

6.2.2.2 Review of past forecasts

EnergyAustralia's regulatory proposal indicates that over the period 2004–05 to 2006–07:[248]

- maximum demand increased at an average annual rate of 3.4 per cent, which is slightly higher than the forecast approved by IPART in its 2004 determination of 3.3 per cent

246 EnergyAustralia, *Regulatory proposal*, p. 42.
247 EnergyAustralia, *Regulatory proposal*, Attachment 13.2, p. 7.
248 EnergyAustralia, *Regulatory proposal*, RIN proforma 2.3.8 confidential, tables 7 and 8.

- energy consumption has grown at an average annual rate of 1.6 per cent which is lower than the growth forecast approved by IPART in its 2004 determination of 2.1 per cent
- customer numbers have grown by approximately 1.2 per cent per annum. By 2006–07, total customer numbers had exceeded the 2004 IPART approved forecast by approximately 3 per cent.[249]

Table 6.4. EnergyAustralia current regulatory control period – forecasts and actuals

	2004–05	2005–06	2006–07
Energy sales (base) – MWh 2004 IPART approved forecast	26490778	27119532	27594722
Energy sales (base) – MWh actuals	26455636	27222653	27356448
Difference	–0.1%	0.4%	–0.9%
System maximum demand (50% POE) – MW – 2004 IPART approved forecast[a]	5305 (winter)[b]	5478 (summer)	5635 (summer)
System maximum demand (50% POE) – MW – actuals[a]	5294 (summer)	5522 (summer)	5636 (summer)
Difference	–0.2%	–0.8%	0.0%

Source: EnergyAustralia, *Regulatory proposal*, RIN proformas, confidential, table 2.3.8.
(a) The 2004 IPART approved forecast anticipated that EnergyAustralia would transition from a winter peaking to summer peaking network in 2005–06.

In July 2007, EnergyAustralia commissioned Charles River Associates International (CRA) to conduct a critical review of its global network energy and peak demand forecasting processes.[250] This review was expected to assess the adequacy of the existing forecasting processes used by EnergyAustralia, identify any weaknesses in the forecasting processes and recommend strategies to address such weaknesses and identify any potential areas of improvement to the forecasting processes.[251] A number of CRA's recommendations were implemented in EnergyAustralia's forecasting methodologies for the purposes of its regulatory proposal for the next regulatory control period.[252]

Also, in May 2008 EnergyAustralia engaged CRA to review its spatial demand forecast for summer 2007–08 and beyond, as this forecast was based on a modified form of the processes it usually uses due to very low peak demands experienced in summer 2006–07.[253] CRA found that the modified spatial demand approach used by EnergyAustralia in constructing the forecast for the summer 2007–08 and beyond was reasonable.[254]

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249 EnergyAustralia, *Regulatory proposal*, RIN proforma 2.3.8 confidential, tables 7 and 8.
250 CRA, confidential, p. 1.
251 CRA, confidential, p. 1.
252 EnergyAustralia, *Regulatory proposal*, attachment 13.2, p. 44.
253 EnergyAustralia, *Regulatory proposal*, Attachment 4.06, pp. 23–8.
254 EnergyAustralia, *Regulatory proposal*, Attachment 4.06, p. 28.

6.2.2.3 Methodology

EnergyAustralia separates its peak demand forecasting process into global and spatial methodologies.

Global

EnergyAustralia outlined its global peak demand forecasting process in the following high level steps:

1. Identify the exogenous drivers of electricity consumption
2. Quantify the relationship between annual changes in the exogenous drivers and the corresponding changes in electricity consumption levels
3. Produce electricity forecasts by inputting sound and independent (where available) projections of the exogenous drivers into the forecast models
4. Monitor and review the forecasts on an ongoing basis to improve the process.[255]

EnergyAustralia also uses a global forecasting methodology to develop its energy consumption forecasts.

Spatial

EnergyAustralia conducted separate spatial peak demand forecasting processes for each zone substation in its suburban, Sydney city and Hunter Valley areas. It also carried out a reconciliation of the present forecast results with actual loads and previous forecasts.[256] EnergyAustralia outlined its overall spatial peak demand forecasting methodology for all areas in the following high level steps:

1. Update input information—including spot loads, load transfers, known network augmentations and embedded generation and capacitors
2. Determine the real load history for each substation
3. Extract non–growth related loads, including large spot loads and transfers
4. Extrapolate a trend line—by performing a least squares regression on the actual loads that have been plotted
5. Consider adjustment for changes in key drivers—to determine whether, and if so how, the peak demand forecast should be adjusted as a result of changes in the drivers that influence each substation's future growth rate and loads
6. Add non–growth related loads—including historical and committed future load transfers and spot loads to allow the forecast to display the latest understanding of the future peak demands for each substation
7. Reconcile or validate the forecast—compare the current season forecasts with the previous forecast of the same season.[257]

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255 EnergyAustralia, *Regulatory proposal*, p. 1.
256 EnergyAustralia, *Regulatory proposal*, p. 6–19.
257 EnergyAustralia, *Regulatory proposal*, pp. 6–22.

6.2.2.4 Customer numbers

EnergyAustralia forecast residential customer numbers on its network to increase by on average 17 331 or 1.2 per cent per annum over the next regulatory control period.[258] It forecast non–residential customer number growth of 0.7 per cent per annum.[259] EnergyAustralia's customer number forecast is based on long-term NSW Department of Planning projections.[260]

6.2.3 Integral Energy

Integral Energy based its load driven expenditure forecasts on maximum demands at 50 per cent POE. Integral Energy stated its network is predominantly summer peaking, and is being affected by an increasing number of high temperature events and lower equipment ratings during summer periods.[261] This is shown in table 6.5.

Table 6.5: Integral Energy's energy and maximum demand forecasts 2009–10 to 2013–14

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14
Energy sales (base) - MWh	17 927 126	18 159 695	18 460 434	18 664 476	18 905 646	1.3%
System maximum demand (50% POE) – MW[a]	4179	4342	4509	4663	4822	3.5%

Source: Integral Energy, RIN, table 2.3.8.
(a) All values are for summer peak demand.

Integral Energy engaged CRA to review all material underlying assumptions and methodologies used in its peak demand, energy consumption and customer number forecasts for its regulatory proposal.[262] As a result of this review, Integral Energy made some revisions to its assumptions and methodologies applied within its forecasts for the next regulatory control period.

6.2.3.1 Key drivers

Integral Energy submitted that the following key factors, unique to its network, have a significant effect on forecasting energy demand, consumption and customer numbers:

- climatic considerations—peak temperatures that are typically higher and more sustained than those of central Sydney and other coastal areas
- customer distribution and growth patterns—the load in Western Sydney is predominantly for residential and small medium enterprises, while load on the Southern Sydney coastal strip and Wollongong is industrial. A very high proportion of new housing in NSW is within Integral Energy's Western Sydney network

258 EnergyAustralia, *Regulatory proposal*, p. 3.
259 EnergyAustralia, *Regulatory proposal*, RIN proforma table 2.3.8, table 1.
260 EnergyAustralia, *Regulatory proposal*, p. 3.
261 Integral Energy, *Regulatory proposal*, p. 66.
262 Integral Energy, *Regulatory proposal*, p. 62.

- impact of air conditioning—the penetration rate for air conditioning units is approximately 62 per cent across Integral Energy's network, but the rate in Western Sydney has reached 74 per cent for residential customers. This is increasing the divergence in growth rates between peak demand and energy consumption, and causing the load factor of Integral Energy's network to decline, meaning that a significant portion of the Integral Energy network must be built to service peak demand for very short periods.[263]

6.2.3.2 Review of past forecasts

Integral Energy provided a summary of growth in peak demand and energy consumption over the 2005–09 regulatory period as compared to the forecasts accepted at the time of IPART's 2004 distribution determination.[264] Over the current regulatory control period, on Integral Energy's network:

- maximum demand has continued to increase at an average annual rate of 3.4 per cent, which is similar to the level accepted by IPART in its 2004 determination[265]

- energy consumption is expected to grow at an average annual rate of 1.6 per cent over the current regulatory control period, which is well below that accepted by IPART in its 2004 determination (2.1 per cent)[266]

- customer numbers are expected to grow on average 0.8 per cent per annum over the current regulatory control period, which is half that accepted by IPART in its 2004 determination.[267]

Table 6.6 contains the IPART approved forecasts and current regulatory control period data to date.

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263 Integral Energy, *Regulatory proposal*, p. 63–65. Integral Energy provided additional information to the AER during the review process, indicating that its latest customer survey results indicate that air conditioner penetration rates have reached 72 per cent over all and 81 per cent in Western Sydney. Integral Energy, *letter to AER RE: MMA draft report,* 29 July 2008, attachment B, p. 9.

264 Integral Energy, *Regulatory proposal*, p. 42.

265 Weather corrected figure. Integral Energy, *Regulatory proposal*, p. 7.

266 1.6 per cent growth includes forecasts for 2008–09 and 2009–10. Integral Energy, *Regulatory proposal*, p. 7 and IPART, *NSW Distribution Pricing 2004–05 to 2008–09 Final Report*, p. 28.

267 Integral Energy, *Regulatory proposal*, p. 42 and RIN proforma 2.3.8, confidential.

Table 6.6: Integral Energy current regulatory control period – forecasts and actuals [a]

	2004–05	2005–06	2006–07
Energy sales (base) – MWh 2004 IPART approved forecast	17 012 488	17 625 677	17 205 804
Energy sales (base) – MWh actuals	16 900 247	17 196 552	17 384 220
Difference	–0.7%	–2.4%	1.0%
System maximum demand (50% POE) – MW – 2004 IPART approved forecast[a]	3350 (summer)	3466(summer)	3560 (summer)
System maximum demand (50% POE) – MW – actuals[b]	3432 (summer)	3649 (summer)	3504 (winter)[b]
Difference	2.4%	5.3%	–1.6%

Source: Integral Energy's regulatory proposal proformas, confidential, table 2.3.8.
(a) Actuals are not weather corrected.
(b) In 2006–07, due to mild summer weather, actual winter maximum demand exceeded summer maximum demand. Actuals are not weather corrected.

6.2.3.3 Methodology

The following is a summary of Integral Energy's demand forecasting methodologies, as provided by CRA.[268]

Energy forecasts

Integral Energy uses different methodologies to forecast residential and non–residential customer energy usage:[269]

- residential energy forecasts were calculated using a bottom–up, appliance end–use analysis methodology
- non–residential energy forecasts were developed using a causal method of forecasting, based on the assumption that demand for electricity is a derived demand. The forecasts drew on relationships between electricity consumption and various exogenous variables, including sector output, wages, energy prices, household income, NSW GSP employment and mortgage interest rates. Economic growth scenarios were developed and then aligned with short-term forecasts based on historical trends through a basic averaging methodology.

Maximum demand forecasts

A bottom–up, or spatial approach was undertaken to construct the load forecasts at zone substation, transmission substation and bulk supply point levels, through the following steps:[270]

268 CRA, confidential, p. 58.
269 CRA, confidential, p. 62.
270 CRA, confidential, pp. 58–59.

- an underlying growth trend was established for each substation, through:
  - standardisation of historical transmission substation maximum demands, using reference temperature and humidity values based on 50 years' history
  - development of an average growth trend via a simple linear regression of the transmission substation weather standardised load data. The final growth trend was determined by adding two standard deviations above this average trend line to achieve a 95 per cent confidence level
  - at substations where weather correlation based on temperature data is not significant, the actual recorded maximum demand was used for the trending analysis
- for the zone substation level, new spot loads, load shifting and historical peak load diversity was taken into account
- forecasts were developed at the transmission substation level, bulk supply points and total system level using historical average diversity factors.

6.2.3.4 Customer numbers

Integral Energy forecast customer numbers on its network to grow at an average annual rate of 1.2 per cent over the next regulatory control period.[271]

6.3 Submissions

The AER received three submissions that addressed the NSW DNSPs' demand forecasts for the next regulatory control period, from EnergyAustralia, the Energy Markets Reform Forum (EMRF), and the Energy Users Association of Australia (EUAA).

EnergyAustralia stated that more recent data, made available since it submitted its regulatory proposal, supports the peak demand and load forecasts underpinning EnergyAustralia's regulatory proposal. In particular, EnergyAustralia submitted that bulk supply point data for June and July 2008 demonstrates that growth in peak demand is significantly exceeding growth in annual energy consumption.[272]

The EMRF stated that the AER must undertake careful analysis of the demand forecasts to determine whether the DNSPs are manipulating the forecasts to increase their revenues. The EMRF stated that it would like to review and independently verify any work of consultants commissioned by the AER to review demand forecasts. The EMRF also submitted that it would be useful to aggregate all of the DNSPs' demand forecasting claims against values used by the National Electricity Market Management Company (NEMMCO) and TransGrid. It stated that the Australian Bureau of Agricultural and Resource Economics (ABARE) could be requested to provide an independent assessment of growth.[273]

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271 Integral Energy, *Regulatory Proposal*, p. 67.
272 EnergyAustralia, *Regulatory Proposal*, p. 2.
273 EMRF, pp. 35–36.

The EUAA sought clarification on the expected contribution of residential air conditioners to peak demand over the current and next regulatory control periods, and of the methodology adopted to derive this information. The EUAA stated that there is no empirical data within the DNSPs' proposals to support the contribution of air conditioners to peak load. It also sought clarification on whether any form of end–use demand forecasting has been carried out as a check on the forecasting methods described in the DNSPs' regulatory proposals.[274]

The EUAA stated that the energy growth figures in the DNSPs' regulatory proposals imply a decoupling of GDP and energy growth, which may require further analysis, as a low energy growth forecast has the potential to lead to higher customer prices.[275]

The EUAA sought the following clarifications related to EnergyAustralia's demand forecasts:[276]

- whether EnergyAustralia's demand forecasts are based on the past four and six seasons' peak demands, or five and seven seasons, and has the confidence level in the demand forecasts been affected as a result of its adjusted method
- what were the underlying causes of peak demand in 2006–07 being lower than forecast
- how does 2007–08 actual demand for Botany Zone compare to the forecasts shown in table 4.2 on page 44 of EnergyAustralia's regulatory proposal.

The EUAA submitted that the AER should carry out a thorough analysis of the accuracy of forecasts in the current and previous regulatory control periods, as an additional check on the forecasts for the next regulatory control period. The EUAA stated that, given the crucial role that peak demand forecasts play in determining capital requirements, the AER should consider carrying out its own independent demand forecasts.[277]

6.4 AER considerations

6.4.1 Structure of assessment

To assist the AER's review of the NSW DNSPs' proposals, the AER engaged McLennan Magasanik Associates (MMA) to independently review the processes used in developing forecasts, and the maximum demand, energy and customer number forecasts provided by EnergyAustralia and Integral Energy for the next regulatory control period. The AER conducted its own review of Country Energy's forecasts and forecast methodologies by reference to the MMA review of EnergyAustralia's and Integral Energy's forecast methodologies. In the following sections, the AER's analysis is separated, firstly presenting the AER's consideration of Country Energy's maximum demand, energy and customer number forecasts and forecast methodologies, followed by the concurrent

[274] EUAA, p. 4, pp. 12–13.
[275] EUAA, p. 13.
[276] EUAA, p. 21.
[277] EUAA, p. 21.

presentation of the AER's consideration of EnergyAustralia's and Integral Energy's forecasts and forecast methodologies.

In selecting the DNSPs' for MMA's review, the AER considered that Country Energy's forecasts would be most suitable for reviewing in house, in recognition of the outcomes of the 2004 review and the fact that NIEIR's forecast methodology had not changed since the 2004 review. The AER reviewed Country Energy's forecasts by reference to key drivers and historical trends on its network. It reviewed the methodology used to develop Country Energy's forecasts by comparison with the forecasting methodologies employed by the other NSW DNSPs, and elements of good methodological practice as highlighted by MMA.

6.4.2 AER review of Country Energy's forecasts

Country Energy's forecasts for the next regulatory control period were developed by NIEIR. In generating the forecasts, NIEIR applied the same methodology it used in generating Country Energy's forecasts for the current regulatory control period. During its 2004 review of Country Energy's demand forecasts, IPART engaged MMA to prepare an independent forecast for the Country Energy region over the current regulatory control period.[278] Following its review, MMA concluded that the most suitable energy forecast was NIEIR's original base–case energy growth forecast, applied to 2002–03 WAPC audited energy data. This was also the energy forecast accepted by IPART in its 2004 final report.[279] MMA's final conclusion on Country Energy's maximum demand forecasts differed from Country Energy's final maximum demand forecasts by 0.1 per cent, which was significantly less than the differences between MMA's final forecasts for EnergyAustralia and Integral Energy and the DNSPs' final forecasts.[280]

6.4.2.1 Key drivers

NIEIR's forecast methodology included a top–down overview of economic and demographic variables likely to impact on electricity demand and consumption.

NIEIR's top–down, econometric forecast took into account its projections for the world, Australian, NSW and Country Energy region economic growth, and considered variables such as: growth in GDP and Gross State Product (GSP); world oil prices; the United Stated sub-prime lending market; the drought in rural Australia; fiscal and monetary policy outlooks; interest rates; exchange rates; employment; inflation; consumer confidence; NSW private business investment; growth in the NSW housing sector, electricity prices and NSW and federal greenhouse gas policies.[281]

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[278] IPART, *NSW Electricity Distribution Pricing Final Report,* p. 221.

[279] This result is equivalent to the AER's request for Country Energy to provide a revised energy forecast, outlined in section 6.4.2.2.
IPART, *NSW Electricity Distribution Pricing Final Report*, pp. 27–28.

[280] For the current regulatory control period: Country Energy's final forecast annual summer maximum demand growth rate was 2.9 per cent. IPART approved MMA's final growth rate of 2.8 per cent. EnergyAustralia's final forecast annual summer peak demand growth rate was 2.9 per cent, IPART approved MMA's forecast rate of 3.3 per cent. Integral Energy's final forecast annual summer peak demand growth rate was 2.9 per cent, IPART approved MMA's forecast rate of 3.1 per cent.
IPART, *NSW Electricity Distribution Pricing Final Report*, p. 28, table 4.3.

[281] NIEIR, pp. 5–21.

NIEIR projected that gross regional product in the Country Energy region is likely to grow at 1.9 per cent over 2007–18 on an average annualised basis, which is 0.9 per cent lower than the NSW average.[282] However, NIEIR projected Country Energy's northern region (including the Mid-North Coast of NSW) will grow at the NSW GSP growth rate, or faster.[283] The AER considers NIEIR's top–down forecast is based on sound assumptions on a wide number of variable inputs.

NIEIR's energy forecast model took into account the number and average electricity consumption of residential dwellings, considering the effects of real income growth, weather variables, population growth, air conditioning sales, GSP and real electricity prices on energy usage.[284] NIEIR's maximum demand forecast model took into account the number of new connections to the network and average energy consumption for both residential and business customers, as well as air conditioner sales and weather variables.[285]

The AER acknowledges that significant falls in international financial markets, and corresponding falls in economic growth associated with the failure of the United States sub-prime lending market, have occurred largely subsequent to the lodgement of Country Energy's regulatory proposal. In its November 2007 report, NIEIR projected that the world economy would fall into a recession sometime over the next four years, following the United States sub-prime lending crisis and oil price rises. The AER understands that this projection was built into the NIEIR forecast models for Country Energy's region.[286] Given NIEIR's projection for global world recession during the next regulatory control period, the AER considers that NIEIR's forecasts took account of the risk of the recent slowdown in global economic growth, but accepts that the likely magnitude of the slowdown may have been understated in the forecasts.

The AER considers NIEIR has conducted a thorough analysis of the economic and demographic outlook for NSW, and implications for maximum demand and energy consumption, through consideration of a wide number of variables and their potential impacts on energy consumption.

6.4.2.2 Historical trends and other forecasts

Maximum demand

Country Energy's regulatory proposal indicates that summer maximum demand growth has exceeded that of winter over recent years, largely corresponding to the increased use of air conditioning. Winter maximum demand growth on Country Energy's network has remained steady over recent years, and NIEIR has forecast that summer peak demand will be higher than winter peak demand on Country Energy's network from regulatory year 2010–11 onwards.[287] This is in line with trends evident across the NEM, and in particular in the ACT and NSW.[288] For the next regulatory control period, NIEIR's maximum demand forecast represents a continuation of recent summer and winter maximum

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282 NIEIR, p. 19.
283 NIEIR, p. 19.
284 Country Energy, *Regulatory proposal*, appendix F, p. 5.
285 Country Energy, *Regulatory proposal*, appendix F, p. 7.
286 NIEIR, p. 5.
287 Country Energy, *Regulatory proposal*, confidential, RIN input sheet 2.3.8, table 4.
288 AER, *ACT draft distribution determination, Draft decision*, 7 November 2008, pp. 46–47.

demand growth, which the AER considers was reasonable to expect at the time the forecast was developed.

The AER compared Country Energy's maximum demand forecasts to the forecasts within TransGrid's 2008 Annual Planning Report (2008 APR), which was released subsequent to the development of Country Energy's demand forecasts.[289] NIEIR's forecasts for summer and winter maximum demand are virtually identical to TransGrid's forecasts within the 2008 APR.[290]

Energy

Over the next regulatory control period, NIEIR forecast energy consumption growth on Country Energy's network to average 1.6 per cent per annum, slightly lower than the 2004 forecast of average annual GWh growth of 1.7 per cent for the current regulatory period.[291] Country Energy's regulatory proposal indicated that residential energy consumption is expected to be constrained by the increased take up of solar and gas hot water systems, influenced by the NSW BASIX program.[292]

However, Country Energy's regulatory proposal indicated that energy consumption on its network has grown at an average of 2.9 per cent per annum over the period 2002–03 to 2006–07.[293] NIEIR has forecast energy consumption over 2007–08 and 2008–09 to be significantly lower, at 0.8 per cent and 1.9 per cent respectively.[294]

Over the current regulatory control period, total energy consumption on Country Energy's network has been around 4 per cent higher than the 2004 IPART approved energy forecast.[295] The 2004 forecast was developed by taking the latest available energy data at the time (that is, energy sales for year 2002–03) and applying a NIEIR base–case growth forecast.[296]

In the course of reviewing Country Energy's energy forecasts, the AER requested a revised energy forecast using unaudited 2007–08 energy sales data as a starting point, for inclusion within this draft decision.[297] However on 21 October 2008 the AER agreed that Country Energy was not required to update its forecasts prior to the draft decision on the basis that the costs would outweigh the benefits. Country Energy stated the costs of doing so would have included fees to NIEIR, while the benefits were limited by the fact that the data would require updating again once the 2007–08 energy sales data is audited. Further, Country Energy also suggested that a material change from the forecasts submitted with its regulatory proposal was not expected.[298]

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289 TransGrid, *2008 NSW Annual Planning Report*, 30 June 2008, p. 5.
290 NIEIR, pp. 115–117; and TransGrid, 2008 APR, p. 29 and tables 4.9 and 4.11.
291 Country Energy, *Regulatory proposal*, confidential, RIN input sheet 2.3.8, table 3.
292 BASIX is the NSW Government's Building Sustainability Index, which sets water usage and greenhouse gas emission reductions on new homes and large extensions.
Country Energy, *Regulatory proposal*, appendix F, p. 6.
293 Country Energy, *Regulatory proposal*, confidential, RIN input sheet 2.3.8, table 3.
294 Country Energy, *Regulatory proposal*, confidential, RIN input sheet 2.3.8, table 4.
295 Country Energy, *Regulatory proposal*, confidential, RIN input sheet 2.3.8, table 5.
296 IPART, *NSW Electricity Distribution Pricing Final Report*, pp. 27–28.
297 AER, email request to Country Energy, 25 September 2008.
298 Country Energy, phone call to AER, 21 October 2008.

The AER's draft decision is to reject the energy forecast provided within Country Energy's regulatory proposal under clause 6.12.1(10) of the transitional chapter 6 rules, as the forecast is an inappropriate input into the AER's PTRM.

The AER requests that Country Energy produce a revised energy forecast once audited weighted average price cap energy sales data for 2007–08 is available. The revised forecast is to use the audited energy data for 2007–08 as a starting point, which should then be grown according to the methodology applied within the original NIEIR base–case energy forecast in Country Energy's regulatory proposal.[299] The new data is to be weather corrected and allocated according to the methodology applied in generating the original energy forecast. The AER requires Country Energy to provide this revised forecast as an updated version of the *Forecast Sales Quantities* table within the *Input* sheet of its PTRM, by COB on 20 February 2009.

Customer numbers

Country Energy's regulatory proposal indicates that customer numbers on its network have fluctuated significantly from year to year over the past nine years. The AER understands this fluctuation may be due to difficulties experienced in accounting for customers following the incorporation of Advance Energy, NorthPower and Great Southern Energy into the Country Energy network in 2001, and then Australian Inland Energy in 2005.[300] NIEIR forecast customer number growth on the Country Energy network to average 1.46 per cent over the next regulatory control period, which represents an average net increase of approximately 11 800 customers per annum over the period.[301] Country Energy's regulatory proposal indicated that over the period 2002–03 to 2006–07, customer numbers have grown by an average of 1 per cent per annum, and it forecasts growth in 2007–08 to be 1.5 per cent.[302]

Given the historical yearly fluctuation in customer numbers, and the expected increase in customer number growth for the last two years of the current regulatory control period, the AER considered that a revised customer number forecast, using the most recent customer numbers should be prepared for consideration in this draft decision. Accordingly, in the course of reviewing the forecasts, the AER requested Country Energy provide a revised customer number forecast, using actual customer numbers as at 30 June 2008 as the starting point for the forecast, then grown at the NIEIR recommended base–case forecast for the remaining years of the next regulatory control period.[303]

However, consistent with the discussion above on energy sales data, on 21 October 2008 the AER agreed that the revised customer number forecast could be provided by Country Energy for consideration in the AER's final decision.[304]

The AER's draft decision is to reject the customer number forecast provided within Country Energy's regulatory proposal under clause 6.12.1(10) of the transitional chapter 6 rules, as it is an inappropriate input into the AER's PTRM. The AER requests that a

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299 NIEIR, pp. 47–76.

300 Country Energy, *Regulatory proposal*, confidential, RIN input sheet 2.3.8, tables 1 and 2.

301 Net increase includes new customer connections and disconnections.
Country Energy, *Regulatory proposal*, confidential, RIN input sheet 2.3.8, tables 1 and 2.

302 Country Energy, *Regulatory proposal*, confidential, RIN input sheet 2.3.8, tables 1 and 2.

303 AER, email request to Country Energy, 25 September 2008.

304 AER, file note of phone meeting with Country Energy, 21 October 2008.

revised customer number forecast be submitted by Country Energy by COB on 20 February 2009.

6.4.2.3 Elements of good methodological practice

The AER reviewed Country Energy's maximum demand, energy and customer number forecasts in light of criteria for good forecasting methodology, as highlighted by MMA.[305]

The AER notes that, while Country Energy's regulatory proposal and the NIEIR report provided some explanation as to NIEIR's forecasting methodology, the AER's understanding of the methodology has been largely developed via its requests for further information throughout the review.[306] The AER considers that NIEIR is a well recognised, reputable economic forecaster, however its report on Country Energy's region did not provide a great deal of information describing its models and processes. The AER notes that during the 2004 IPART review, the lack of transparency of NIEIR's methodology was noted in the consultant's final report.[307] However, the AER considers that the additional information provided by Country Energy throughout the review process was sufficient to enable the AER to develop a reasonable understanding of the methodology used to develop the forecasts.

Weather normalisation

Weather normalisation of historical data is a key element of maximum demand forecasting. Weather normalisation is typically carried out by first establishing relationships between summer and winter network demand and temperature, determining 'normal' weather for each season (according to appropriate POE), and using this information to estimate weather normalised maximum demand over an historical period.[308]

NIEIR analysed Country Energy's historical demand data for each county council area within the network, and extracted the maximum non-coincident demands for each season and corresponding ambient temperatures, for years 2004–05 to 2006–07.[309] NIEIR then calculated 10, 50 and 90 per cent POE for each region, based on the last 20 years of daily temperature data from the National Climate Centre.[310] This information was then used to generate maximum demand forecasts for summer and winter for each county council area within Country Energy's network. The AER considers NIEIR's methodology for weather correction to be reasonable.

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305 That is elements of good methodological practice as described by:
MMA, *Final report to the Australian Energy Regulator – Review of EnergyAustralia's maximum demand forecasts*, 1 August 2008, confidential, pp. 21–22, 29–30; and
MMA *Regulatory proposal 2009–14 – Review of EnergyAustralia's customer number and energy forecasts*, 26 September 2008, confidential, pp. 24–25.

306 Country Energy, response to information request, 21 July 2008, 28 August 2008 and 3 October 2008.

307 MMA, Review *of demand forecasts by the electricity Distribution Network Service Providers for the 2004 electricity network review,* April 2004, pp. 11–12.

308 MMA, *EnergyAustralia's maximum demand forecasts*, confidential, p. 21.

309 NIEIR, pp. 30–34.

310 NIEIR, p. 35. NIEIR used every day temperature data in developing the POE percentiles, electing not to exclude weekends or holiday periods as Country Energy's region has experienced weekend peaks in certain areas.
Country Energy, response to the AER's questions of 25 September 2008, 3 October 2008.

Disaggregation and appliance usage or sales surveys

MMA considers that load research of residential and non-residential customers' contributions to maximum demand and energy should be conducted on a regular basis to measure variations in the structure of maximum demand and energy consumption. MMA also recommend regular customer surveys or appliance sales information be used to establish air conditioner and other appliance penetration rates. This information should then be related to historical weather normalised maximum demand in each year as part of a global maximum demand model.[311]

Country Energy separates forecasts of energy usage between residential, business and public lighting customers. It also separates its business load into subcategories of low voltage, high voltage and sub–transmission customers.[312] The AER understands that NIEIR did not disaggregate its maximum demand forecast into customer types, however the forecast is separated into the county council areas.[313]

No appliance models were used in Country Energy's forecasts, however NIEIR estimated air conditioning penetration through analysis of air conditioning sales data, and incorporated this data into its maximum demand forecasts.[314] NIEIR's model relies largely on historical data and straight line projections, which it considers negates the need for appliance modelling.[315] The AER considers that Country Energy's customers are likely to be more diverse that those of other NSW DNSPs, due to the large geographical area which the network encompasses. The AER considers that conducting appliance usage surveys for the purposes of developing energy and maximum demand forecasts may be of limited value given Country Energy's customer diversity. The AER also considers that it is likely that trends in customer energy usage are captured within the historical data used to generate the forecasts.[316]

Treatment of spot loads

Appropriate treatment of spot loads, and consistency between top down (econometric or global) and bottom up (spatial) forecasts are considered important elements of maximum demand forecasting. Country Energy does not take into account large planned generation or anticipated large new customers within its forecasting process, as it finds that typically spot loads are unreliable.[317] However, NIEIR's forecasts account for spot loads implicitly through historical growth trends.[318] The AER considers this is a reasonable approach for Country Energy's network, given the size and diversity of the network and Country Energy's comments on the unreliability of planned spot loads. The AER considers NIEIR's forecast methodology is well balanced, and does not introduce any double–counting of spot loads or load transfers.

NIEIR developed a top down scenario based outlook for the Country Energy network, which accounted for a variety of econometric variables. The AER understands that

311 MMA, *EnergyAustralia's maximum demand forecasts*, confidential, p. 21.
312 Country Energy, response to the AER's questions of 25 September 2008, 3 October 2008.
313 NIEIR, p. 30.
314 Country Energy, response to the AER's questions of 4 July 2008, 14 July 2008.
315 Country Energy, response to the AER's questions of 4 July 2008, 14 July 2008.
316 Country Energy, response to the AER's questions of 4 July 2008, 14 July 2008.
317 Country Energy, verbal response to AER's questions, 28 August 2008.
318 Country Energy, verbal response to AER's questions, 28 August 2008. The AER considers that no double counting of spot loads has occurred in NIEIR's forecasts.

NIEIR's top down forecast was reconciled with the spatial forecasts produced for each county council area.

Accounting for historical trends

MMA considers that energy consumption forecasts should review historical trends in consumption and key drivers, balance trends against expected changes in key drivers, and explain if, why and how the future should be different to the recent past.[319] NIEIR's energy forecast methodology is based on analysis of Country Energy's historical energy consumption growth. NIEIR's forecasts also take into account changes in key economic and demographic variables through NIEIR's top–down, econometric forecast model. The AER considers that NIEIR's forecast methodology appropriately accounts for historical trends and changes in key variables in Country Energy's energy consumption.

6.4.3 Consultant's review of EnergyAustralia's and Integral Energy's forecasts

The AER engaged MMA to assist it in reviewing EnergyAustralia's and Integral Energy's forecasts and forecast methodologies for maximum demand, energy and customer numbers over the next regulatory control period. MMA's analysis was split into two separate reviews:

- a review of the maximum demand forecast methodologies and forecasts, to assist the AER in assessing the reasonableness of the DNSPs' augmentation capex proposals
- a review of the energy and customer number forecast methodologies and forecasts, to assist the AER in converting the DNSPs' revenue requirements to prices for the next regulatory control period.

The review process involved MMA first reviewing the forecasts and methodologies described within the DNSPs' regulatory proposals, before seeking additional information. Meetings were held with both DNSPs to allow them to present their forecasts, and to allow MMA to question the DNSPs' forecasting staff.

MMA produced two reports for each DNSP.[320] The AER has decided that the reports are to remain confidential, due to confidential information in the reports and an understanding reached with the DNSPs on the conduct of this review process. However, the following sections provide a description of MMA's assessment process and conclusions on EnergyAustralia's and Integral Energy's maximum demand, energy and customer number forecasts and forecast methodologies.

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319 MMA *EnergyAustralia's customer number and energy forecasts*, confidential, p. 25.

320 MMA, *EnergyAustralia's maximum demand forecasts*, confidential,
MMA *EnergyAustralia's customer number and energy forecasts*, confidential,
MMA, *Regulatory proposal 2009–14 –Review of Integral Energy's maximum demand forecasts*, 15 August 2008, confidential,
MMA *Regulatory proposal 2009–14 – Review of Integral Energy's customer number and energy forecasts*, 26 September 2008, confidential.

6.4.3.1 Maximum demand

MMA reviewed the network-wide, or global, maximum demand forecasts as well as the forecasts at the zone substations, or spatial, level. MMA focussed on the summer maximum demand forecasts, as both networks have summer peaking loads.

Global maximum demand forecasts

EnergyAustralia

MMA found that EnergyAustralia's global maximum demand forecast is approximately in-line with recent trends.[321] MMA considered several key drivers of demand, including air conditioning, residential customer number growth, non-residential usage growth, energy efficiency programs, climate change and spot loads. MMA assessed the impact of these drivers on maximum demand as compared with recent history.[322] MMA also compared forecasts within the TransGrid 2008 APR and TransGrid's 2007 Annual planning Report (2007 APR), finding that the summer maximum demand growth projections for EnergyAustralia's network have not varied significantly in the past 12 months.[323] MMA found that, overall, it is reasonable to expect growth to continue approximately as it has over the past several years.[324]

MMA reviewed EnergyAustralia's global forecast methodology according to what it considers are elements of good methodological practice in forecasting, finding that:[325]

- EnergyAustralia's weather normalisation methodology is reasonable
- EnergyAustralia's use of load research from 2001 to establish different customers' contributions to peak demand is good; however, it should be updated
- the use of information about customers' air conditioning ownership and other key forecast inputs is good
- the global forecast model is constructed in a logical manner, and a level of detail commensurate with available information
- the methodology is reasonably documented for the purposes of the AER's review.

MMA concluded that EnergyAustralia's global forecast methodology is reasonable, and the forecast is acceptable for the purposes of assessing EnergyAustralia's augmentation capex proposal for the next regulatory control period.[326]

Integral Energy

MMA found that Integral Energy's global maximum demand forecasts were significantly higher than recent history, both starting at a higher level than the trendline, and projecting growth at a rate much faster than recent history.[327] MMA analysed key drivers including:

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321 MMA, *EnergyAustralia's maximum demand forecasts*, confidential, p. ii.
322 MMA, *EnergyAustralia's maximum demand forecasts*, confidential, pp. 5–12.
323 MMA, *EnergyAustralia's maximum demand forecasts*, confidential, p. 14.
324 MMA, *EnergyAustralia's maximum demand forecasts*, confidential, p. iii.
325 MMA, *EnergyAustralia's maximum demand forecasts*, confidential, p. 49.
326 MMA, *EnergyAustralia's maximum demand forecasts*, confidential, p. 49.
327 MMA, *Integral Energy's maximum demand forecasts*, confidential, p. 1.

air conditioning; residential customer number growth; non-residential usage growth; energy efficiency programs; climate change and spot loads. MMA found that, overall, it appears reasonable to expect growth in maximum demand on Integral Energy's network to continue at the rate is has grown over recent years, or indeed a little slower.[328] MMA compared the maximum demand forecasts for the Integral Energy region within the 2007 APR and 2008 APR, finding that the 2008 TransGrid forecast shows both a lower starting point and faster growth rate than that of 12 months prior.[329] This change in projection is attributed by TransGrid to strong future rises in air conditioning loads, however, MMA's review of air conditioning penetration concluded that it is unlikely to grow faster than it has over the current regulatory control period.[330]

MMA's review of Integral Energy's global forecast methodology concluded that its global forecasts were of limited value in the forecasting process.[331] MMA found that Integral Energy's global maximum demand forecast appeared unreasonable and inconsistent with the forecast slow–down in some of the key drivers of maximum demand, including air conditioner load and new customer connections.[332] MMA considered that Integral Energy's global forecasts of summer maximum demand were overstated by approximately 100 MW (or 2.5 per cent) in 2008, and up to 400 MW in 2014.[333]

MMA recommended that Integral Energy develop and apply a global model that is independent of the spatial demand forecasts, based on analysis of key drivers. MMA recommended that the model be supported by weather normalisation at a global level, load research to enable it to disaggregate maximum demand into key residential and industrial customer components, and robust testing against historical peak demand.[334]

Spatial maximum demand forecasts

For MMA's review of the DNSPs' spatial forecasts, the AER selected two zone substations for detailed review of the forecast methodology employed.

EnergyAustralia

For EnergyAustralia, the AER selected Charmhaven and Mortdale zone substations for detailed review by MMA, as EnergyAustralia had forecast high growth and a corresponding need for capex for both substations in the next regulatory control period.[335] MMA formed the following conclusions on EnergyAustralia's spatial maximum demand forecast methodology:

- the methodology is well described and documented, and the approach is generally well considered and followed
- most of the spatial load history is not weather normalised, which is a flaw in the methodology. While this has not resulted in significant concerns regarding

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328 MMA, *Integral Energy's maximum demand forecasts*, confidential, pp. 11–19.
329 MMA, *Integral Energy's maximum demand forecasts*, confidential, p. 21.
330 MMA, *Integral Energy's maximum demand forecasts*, confidential, p. 14.
331 MMA, *Integral Energy's maximum demand forecasts*, confidential, p. 4.
332 MMA, *Integral Energy's maximum demand forecasts*, confidential, pp. 4, 14–15.
333 MMA, *Integral Energy's maximum demand forecasts*, confidential, p. 51.
334 MMA, *Integral Energy's maximum demand forecasts*, confidential, pp. 51–52.
335 MMA, *EnergyAustralia's maximum demand forecasts*, confidential, p. 30.

EnergyAustralia's forecasts for the next regulatory control period, it should be addressed in future maximum demand forecasts

- it is not clear how the key global drivers are translated and reconciled with the spatial projection, however the aggregate spatial forecast growth is consistent with the global forecast growth

- the input information used is reasonable.[336]

MMA concluded that EnergyAustralia's spatial forecast methodology is reasonable, and the forecast is acceptable for the purposes of assessing its augmentation capex proposal for the next regulatory control period.[337]

Integral Energy
For Integral Energy, the AER selected Prestons and Bringelly zone substations for detailed review by MMA. Integral Energy stated that the two zone substations are located within the rapidly growing South West Sector of the network.[338] MMA formed the following conclusions following its review of Integral Energy's spatial maximum demand forecast:

- the spatial forecast methodology was not well described or documented, and the treatment of spot loads and lot releases is likely to result in double-counting of growth

- weather normalisation was not carried out on all transmission substations, and the use of a single weather station to record temperatures on the network is inadequate, given the diversity of the network area

- key drivers were not considered in the spatial forecasts, and as a result the network planning does not consider a wider economic or demographic outlook

- the timeliness of lot release information was inadequate

- the methodology, where described, was generally well followed.[339]

MMA concluded that the Integral Energy spatial maximum demand forecast methodology was inadequate, and that the spatial maximum demand forecasts were likely to be significantly over-optimistic.[340]

6.4.3.2 Energy and customer number forecasts

In reviewing EnergyAustralia's and Integral Energy's energy and customer number forecasts for the next regulatory control period, MMA considered a number of key drivers, including: economic growth; customer numbers, population and housing growth;

336 MMA, *EnergyAustralia's maximum demand forecasts*, confidential, p. 50.
337 MMA, *EnergyAustralia's maximum demand forecasts*, confidential, p. 50.
338 MMA, *Integral Energy's maximum demand forecasts*, confidential, p. 39.
339 MMA, *Integral Energy's maximum demand forecasts*, confidential, p. 52.
340 MMA, *Integral Energy's maximum demand forecasts*, confidential, pp. 52–53.

average usage per residential customer; energy efficiency and greenhouse policies; prices of electricity; and climate.[341]

EnergyAustralia

MMA analysed EnergyAustralia's average residential usage, residential and non-residential energy forecasts for the next regulatory control period. EnergyAustralia forecast a strong decline in average residential usage, largely due to falling water heating load as customers replace electric storage hot water systems with solar and gas systems.[342] MMA considered this forecast is reasonable, however, stated that the 2007–08 starting point forecast, which is more than 200kWh below the 2006–07 actual energy sales figure, had not been adequately justified.[343]

MMA recommended that the AER request EnergyAustralia provide a revised energy consumption forecast, using the 2007–08 WAPC energy consumption data as a starting point.[344] MMA recommended that the new data be weather corrected, with weather corrections allocated to customer class in line with the methodology carried out in developing the original forecasts.[345] MMA also recommended that, in generating the revised forecast, consideration be given to using recent historical trends.[346]

In reviewing EnergyAustralia's residential energy forecast, MMA found that EnergyAustralia had made an error in its calculations relating to new customers' energy usage, resulting in the forecast being slightly understated.[347] MMA found that the non-residential energy forecast was reasonable, although recommended EnergyAustralia use a more recent forecast of GSP than that used in generating its non-residential energy forecast.[348]

MMA found that EnergyAustralia's customer number forecast is largely consistent with trends experienced in the recent past.[349] Based on its assessment of key drivers, MMA concluded that EnergyAustralia's forecast appears reasonable, apart from its forecast for regulatory year 2007–08.[350] MMA recommended that the customer number forecast should be updated for the most recent data, by using actual customer numbers at June 30 2008 as a starting point for a revised forecast.[351]

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341 MMA *EnergyAustralia's customer number and energy forecasts*, confidential, p. ii and MMA *Integral Energy's customer number and energy forecasts*, confidential, p. ii.
342 MMA, *EnergyAustralia's customer number and energy forecasts*, confidential, p. iv
343 MMA, *EnergyAustralia's customer number and energy forecasts*, confidential, p. iv.
344 MMA, *EnergyAustralia's customer number and energy forecasts*, confidential, pp. iv–v.
345 MMA, *EnergyAustralia's customer number and energy forecasts*, confidential, p. vii; and AER, File note of phone meeting with MMA, held 16 September 2008.
346 MMA, *EnergyAustralia's customer number and energy forecasts*, confidential, p. vii.
347 MMA estimated that the error is likely to result in the forecast being understated by 0.4 or 0.3 per cent. MMA, *EnergyAustralia's customer number and energy forecasts*, confidential, p. 53.
348 EnergyAustralia used GSP growth inputs in the growth rates within the TransGrid 2007 APR (based on NIEIR's 2007 forecasts) in generating its non-residential energy forecast. MMA recommend EnergyAustralia use a more recent GSP forecast, from NIEIR or another forecaster. MMA, *EnergyAustralia's customer number and energy forecasts*, confidential, p. 59.
349 MMA, *EnergyAustralia's customer number and energy forecasts*, confidential, p. iii.
350 MMA, *EnergyAustralia's customer number and energy forecasts*, confidential, p. iii.
351 MMA, *EnergyAustralia's customer number and energy forecasts*, confidential, p. iii.

Integral Energy

MMA analysed Integral Energy's average residential usage, and residential and non-residential energy forecasts for the next regulatory control period. Like EnergyAustralia, Integral Energy also forecast strong declines in average usage, largely due to falling water heating load.[352] MMA stated that it is reasonable to expect such a decline, however Integral Energy's 2008 starting point was inadequately justified.[353] MMA stated that this strong decline in average usage was also influencing Integral Energy's residential energy consumption forecast.[354] MMA found that Integral Energy's non-residential energy forecast relied heavily on an average of NIEIR's base and low–case GSP forecasts.[355] MMA stated that this approach is flawed, but considered that the energy forecast determined by Integral Energy was not unreasonable overall.[356] MMA recommended that the starting point used for Integral Energy's energy forecast should be reviewed when the 2007–08 WAPC energy consumption data becomes available.[357]

MMA found that Integral Energy's customer number forecasts were significantly lower than trends experienced within the recent past, and materially lower than that forecast by NIEIR for the region.[358] Again, Integral Energy used an average of NIEIR base and low–case growth forecasts of household numbers in its region, resulting in very low forecasts of customer numbers.[359] MMA stated that this approach is inappropriate and understates customer numbers.[360] MMA recommended that Integral Energy provide a revised customer number forecast by using actual customer numbers at June 30 2008 as a starting point, escalated at the base–case growth rate recommended by NIEIR.[361]

6.4.3.3 AER considerations

The AER analysed MMA's findings and recommendations regarding EnergyAustralia's and Integral Energy's maximum demand, energy and customer number forecasts. Overall, the AER considers MMA's analysis is sound, and based on appropriate information supplied by the DNSPs.

Maximum demand

MMA concluded that EnergyAustralia's global and spatial maximum demand forecasting methodologies were sound, and that the resulting forecasts are reasonable.[362] The AER considers that EnergyAustralia's maximum demand forecasts provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the transitional chapter 6 rules.

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352 MMA, *Integral Energy's customer number and energy forecasts*, confidential, p. iii.
353 MMA, *Integral Energy's customer number and energy forecasts*, confidential, p. iii.
354 MMA, *Integral Energy's customer number and energy forecasts*, confidential, p. v.
355 MMA, *Integral Energy's customer number and energy forecasts*, confidential, p. v.
356 MMA, *Integral Energy's customer number and energy forecasts*, confidential, p. v.
357 MMA, *Integral Energy's customer number and energy forecasts*, confidential, p. vii.
358 MMA *Integral Energy's customer number and energy forecasts*, confidential, p. iii, referring to NIEIR, *Economic scenarios for the Integral Region*, March 2008.
359 MMA *Integral Energy's customer number and energy forecasts*, confidential, p. iii.
360 MMA, *Integral Energy's customer number and energy forecasts*, confidential, p. iii.
361 The NIEIR base–case growth rate was provided in NIEIR, *Economic scenarios for the Integral Region*, March 2008, pp. 32–33.
MMA, *Integral Energy's customer number and energy forecasts*, confidential, p. iii.
362 MMA, *EnergyAustralia's maximum demand forecasts*, confidential, p. 49.

MMA concluded that Integral Energy's global and spatial maximum demand forecasting methodologies were inadequate, and that the forecasts were likely to significantly overstate growth in maximum demand in the next regulatory control period. In the course of the review the AER requested that Integral Energy address a number of methodological concerns raised by MMA, and prepare a revised spatial maximum demand forecast consistent with recent trends in maximum demand and corresponding macroeconomic drivers.[363] The AER requested that a revised capex forecast be prepared on the basis of the revised spatial demand forecasts.[364]

In its response, Integral Energy indicated that it had found an error within weather normalised historical data that, when corrected, resulted in the original global forecast being increased, to substantially reduce the gap between Integral Energy's spatial and global forecasts.[365] Integral Energy also provided a revised spatial demand forecast, which took into account a number of MMA's recommended changes to its methodology, and resulted in a reduction in its maximum demand forecast of 202 MW in 2013–14.[366] Notwithstanding MMA's recommendations concerning improvements that Integral Energy could make to its forecasting processes, the AER considers Integral Energy's revised maximum demand forecasts provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the transitional chapter 6 rules. The impact of the revised spatial demand forecast on Integral Energy's capex program is discussed in chapter 7.

The AER considers that the maximum demand forecast within Integral Energy's regulatory proposal does not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the transitional chapter 6 rules. The AER's draft decision is to accept the revised maximum demand forecast provided by Integral Energy on 29 August 2008.

Energy and customer numbers

MMA concluded that EnergyAustralia's energy and customer number forecast methodologies were reasonable for the purposes of the AER's review. However, MMA recommended that the forecasts be updated to account for the most recent data, including customer numbers as at 30 June 2008 and WAPC energy sales data for 2007–08.[367]

Following the completion of MMA's final report on EnergyAustralia's energy and customer number forecasts, the AER requested that EnergyAustralia provide, for this draft decision:[368]

- a revised customer number forecast, using June 30 2008 customer numbers as a starting point

363 AER, letter to Integral Energy, dated 11 August 2008.

364 AER, letter to Integral Energy, dated 11 August 2008.

365 Integral Energy, response to 11 August 2008 letter from the AER on Integral Energy's Maximum Demand forecast for the 2009–14 regulatory period, 29 August 2008.

366 Integral Energy, response to 11 August 2008 letter from the AER on Integral Energy's Maximum Demand forecast for the 2009–14 regulatory period, 29 August 2008.

367 MMA, *EnergyAustralia's customer numbers and energy forecasts,* pp. iv–v.

368 AER, letter to EnergyAustralia, 8 October 2008.

- a revised energy consumption forecast, using unaudited 2007–08 WAPC energy data, and generated according to the methodologies for allocating the growth between customer types and weather correction used in EnergyAustralia's original energy forecast. The AER also requested that the revised energy forecast incorporate the revised customer number forecast, and take into account recent trends in demand on the network.

EnergyAustralia provided revised customer number and energy forecasts to the AER on 29 October 2008.[369] The revised forecasts are provided in table 6.7.

Table 6.7: EnergyAustralia's revised energy and customer number forecasts

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth rate
Original energy forecast (2 June 2008)[a]	31 564 556	32 084 159	32 553 666	32 834 721	33 234 323	1.4%
Revised energy forecast (29 October 2008)[a]	31 403 841	31 819 691	32 181 781	32 351 699	32 636 395	1.1%
Original customer number forecast (2 June 2008)[b]	2066 562	2079 885	2094 218	2108 474	2122 738	0.6%
Revised customer number forecast (29 October 2008)[b]	2073 691	2087 691	2102 703	2117 640	2132 584	0.6%

Source: EnergyAustralia, *Regulatory proposal*, PTRM, confidential; and EnergyAustralia, response to AER's request for information on energy and customer number forecasts, 29 October 2008.

(a) Energy forecast numbers include some large customer loads that are typically excluded from energy forecasts.

(b) Full year equivalent data.

MMA concluded that Integral Energy's energy forecast methodology was reasonable for the purposes of the AER's review of Integral Energy's regulatory proposal. However, MMA recommended that the forecast be updated to account for the most recent data, being WAPC energy sales data for 2007–08.[370]

MMA considered that Integral Energy's customer number forecast methodology was flawed due to the use of an average of NIEIR's base and low–case customer number forecasts. MMA considered the forecast was likely to understate customer number growth in the next regulatory control period, and recommended a revised forecast be provided to the AER, starting with customer numbers at 30 June 2008 and escalated at the NIEIR recommended base–case growth rate.[371]

369 EnergyAustralia, response to AER's request for information on energy and customer number forecasts, 29 October 2008. The AER notes that the revised energy and customer number forecasts provided by EnergyAustralia on 29 October 2008 do not constitute a revised regulatory proposal.

370 MMA, *Integral Energy's customer numbers and energy forecasts*, confidential, p. iii.

371 Base–case energy forecast within NIEIR, *Economic Scenarios for the Integral Region*, March 2008, p. 32.

Following the completion of MMA's review, the AER requested that Integral Energy provide, for inclusion within this draft decision:

- a revised customer number forecast, using June 30 2008 customer numbers as a starting point, and escalated at the base–case forecast growth rates recommended by NIEIR for its region[372]

- a revised energy consumption forecast, using unaudited 2007–08 WAPC energy data, and generated according to the methodologies for allocating the growth between customer types and weather correction used in Integral Energy's original energy forecast. The AER also requested that the revised energy forecast incorporate the revised customer number forecast, and take into account recent trends in demand on the network.[373]

Integral Energy provided revised customer number and energy forecasts to the AER on 31 October 2008.[374] However Integral Energy's response reiterated its view that the methodology used to develop its original customer number forecast, in which an average of the base and low case NIEIR scenarios was used, is more likely to provide a more realistic outcome for the customer number forecast.[375] The revised forecasts are set out in table 6.8.

Table 6.8: Integral Energy's revised energy and customer number forecasts

	2009–10	**2010–11**	**2011–12**	**2012–13**	**2013–14**	**Average annual growth rate**
Original energy forecast (2 June 2008)	17 927 126	18 159 695	18 460 434	18 664 476	18 905 646	1.3%
Revised energy forecast (31 October 2008)	17 886 489	17 975 821	18 279 960	18 516 290	18 780 813	1.2%
Original customer number forecast (2 June 2008)	857 362	867 118	877 711	888 071	899 438	1.1%
Revised customer number forecast (31 October 2008)	869 497	881 923	895 362	908 553	922 777	1.4%

Source: Integral Energy, *Regulatory proposal*, proforma 2.3.8, tables 1, 3;
Integral Energy, *Forecasts for Energy and Customer numbers*, 31 October 2008.

The AER considers that EnergyAustralia's and Integral Energy's revised energy and customer number forecasts have been generated according to sound methodologies, are based on the latest available data, and represent reasonable forecasts of energy consumption and customer numbers for the next regulatory control period.

372 NIEIR, *Economic Scenarios for the Integral Region*, March 2008, p. 32.

373 AER, letter to Integral Energy, 10 October 2008.

374 Integral Energy, *Forecasts for Energy and Customer numbers*, 31 October 2008. The AER notes that the revised energy and customer number forecasts provided by Integral Energy on 31 October 2008 do not constitute a revised regulatory proposal.

375 Integral Energy, *Forecasts for Energy and Customer numbers*, 31 October 2008, p. 2.

The AER's draft decision is to reject the energy and customer number forecasts within EnergyAustralia's and Integral Energy's regulatory proposals, as it considers they are inappropriate inputs into the AER's PTRM.

The AER considers the revised customer number forecasts provided by EnergyAustralia and Integral Energy on 29 and 31 October 2008 respectively are appropriate inputs into the PTRM, and accepts them under clause 6.12.1(10) of the transitional chapter 6 rules.

While the AER considers the revised energy forecasts, provided by EnergyAustralia and Integral Energy on 29 and 31 October 2008 respectively, represent reasonable inputs into the PTRM, the AER considers that there would be merit in the DNSPs each providing a second revised energy forecast, once the WAPC energy sales data for 2007–08 is audited. The revised forecasts are to use the audited WAPC energy data for 2007–08 as a starting point. The new data is to be weather corrected and allocated according to the methodology applied in generating the original energy forecasts, and should incorporate the revised customer number forecasts. The AER requires EnergyAustralia and Integral Energy to provide these revised energy forecasts as an updated version of the *Forecast Sales Quantities* table within the *Input* sheet of each DNSPs' PTRM, by COB on 20 February 2009.

6.4.4 Consideration of submissions

6.4.4.1 EnergyAustralia

The AER notes EnergyAustralia's submission that the most recent data further supports the maximum demand and energy forecasts within its regulatory proposal. The review of EnergyAustralia's maximum demand, energy and customer number forecasts has concluded that the forecast methodologies are reasonable, however the AER considers that the energy forecast should be further revised to take into account the most recent data, and requests revised energy forecasts in section 6.4.3.3.

6.4.4.2 EMRF

The AER notes the EMRF's statement that the AER should undertake careful analysis of the demand forecasts. The AER engaged a consultant to review EnergyAustralia's and Integral Energy's forecasts, and reviewed Country Energy's forecasts by reference to the consultant's review processes. The AER has decided that MMA's final reports are to remain confidential, due to confidential information contained within. However, the AER has outlined MMA's analysis and findings on both DNSPs' forecast methodologies and forecasts in section 6.4.3.

The EMRF also suggested that the AER compare an aggregate of the DNSPs' forecasts with forecasts developed by NEMMCO and TransGrid. During the review, the AER and MMA compared the DNSPs' forecasts to forecasts within TransGrid's 2008 APR. The AER notes that an aggregate comparison of the NSW DNSPs' forecasts with TransGrid or NEMMCO's NSW forecasts would not provide a useful point of analysis, as TransGrid's and NEMMCO's aggregate forecasts account for large transmission customers, imports and exports of electricity in NSW, and settlement residues. The AER also notes that the relevance of spatial maximum demand forecasts for the AER's distribution determination is in determining appropriate capex on each substation for the next regulatory control period. The AER considers that its consideration of spatial maximum demand forecasts would not be assisted by an aggregate top–down comparison with TransGrid's or NEMMCO's forecasts. Also, the allocation of energy between customer classes is critical in energy forecasting, and as such a top–down aggregate comparison with another aggregated forecast would not be useful for assessing the appropriateness of the DNSPs' energy forecasts.

The AER considers that it has conducted a careful and thorough analysis of the NSW DNSPs' maximum demand, energy and customer number forecasts, and considers that the final forecasts reflect reasonable assumptions and projections.

6.4.4.3 EUAA

The AER notes the EUAA's submission on the impact of air conditioning load on maximum demand. MMA considers that while air conditioning is only one of a number of appliances used in homes, it is understood to have contributed significantly to the increase in peak demand seen over the past decade, from high penetration in new homes, increased penetration in existing homes and increased power of appliances.[376]

MMA compared EnergyAustralia's and Integral Energy's air conditioner penetration data to Australian Bureau of Statistics data on residential cooling appliance penetration across Australia, as well as a number of air conditioning surveys.[377] Both EnergyAustralia and Integral Energy have carried out research on a sample of customers' loads on a half hourly basis, to determine residential customers with/without air conditioners' energy consumption and contributions to maximum demand. Integral Energy has also carried out customer surveys to determine air conditioner penetration rates among its network customers.

The AER notes that, as part of the review of key inputs and drivers of maximum demand, MMA found Integral Energy's original forecast growth in air conditioner penetration on its network was likely to be optimistic.[378] This was one of the factors that led MMA to conclude that Integral Energy's maximum demand forecast was likely to be overstated. The AER requested that Integral Energy address methodological concerns raised by MMA through the preparation of a revised spatial maximum demand forecast, consistent with recent trends in maximum demand and taking into account MMA's recommendations. As discussed in section 6.4.3.3, Integral Energy provided a revised maximum demand forecast on 29 August 2008.[379] The AER considers Integral Energy's revised maximum demand forecast provides a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the transitional chapter 6 rules.

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376 MMA, *Integral Energy's maximum demand forecasts*, confidential, p. 5. and MMA, *Integral Energy's maximum demand forecasts*, confidential, pp. 11–15.

377 MMA used Australian Bureau of Statistics data series 4602.0.

378 In its regulatory proposal, Integral Energy suggested that air conditioning penetration was likely to continue to increase at the rate it has over the past few years, based on its own customer surveys. MMA considered that the rate of increase of air conditioning penetration over the next regulatory control period is unlikely to be greater than it has been over the current regulatory period, as Integral Energy's network approaches air conditioner saturation.
MMA, *Integral Energy's maximum demand forecasts*, confidential, p. 51.

379 Integral Energy, response to 11 August 2008 letter from the AER on Integral Energy's Maximum Demand forecast for the 2009–14 regulatory period, 29 August 2008.

Country Energy's maximum demand forecast methodology was simpler than that applied by EnergyAustralia and Integral Energy, relying on historical trend analysis to generate forecasts. While Country Energy did not model customers' appliance usage, NIEIR's forecasting methodology did take into account air conditioner sales in the Country Energy region.[380] The AER considers that, due to the diversity of Country Energy's customers and the geographic diversity of its network, weather normalised historical trend projections that account for air conditioner sales and other key drivers, is an appropriate method for forecasting maximum demand on Country Energy's network.

The AER and its consultants consider that the DNSPs' proposals provide sufficient data on the impact of air conditioning penetration on peak demand, and the methodologies used to carry out the maximum demand forecasts.

The AER notes the EUAA's observation that the DNSPs' regulatory proposals imply a decoupling of GDP and energy growth, and that this may require further analysis by the AER. Forecasts of GDP and GSP are considered key inputs into non-residential customers' energy consumption forecasts. However, a number of other key inputs influence customers' energy usage, such as: population growth; average energy usage per customer (including changing patterns in appliance usage and appliance efficiency); federal and state energy efficiency and greenhouse gas policies; the prices of electricity and other energy sources; and climatic conditions.[381]

The AER and its consultants have analysed the NSW DNSPs' energy consumption forecasts, paying particular attention to the use of key inputs. The AER considers that the energy forecasts of Country Energy, and revised energy forecasts of EnergyAustralia and Integral Energy are reasonable inputs for the purposes of calculating X factors and prices for the next regulatory control period.

The EUAA sought the following clarifications related to EnergyAustralia's demand forecasts:

- whether EnergyAustralia's demand forecasts are based on the past four and six seasons' peak demands, or five and seven seasons, and whether the confidence level in the demand forecasts has been affected as a result of its adjusted method

- what were the underlying causes of peak demand in 2006–07 being lower than forecast

- how does 2007–08 actual demand for Botany Zone compare to the forecasts shown in table 4.2 on page 44 of EnergyAustralia's regulatory proposal?

The AER has investigated the issues raised by the EUAA in some detail with the cooperation of EnergyAustralia. The AER notes that EnergyAustralia's area plans which underpin its capex program were based on five and seven year histories for summer 2005–06. As part of its regulatory proposal and supporting information, the AER required each of the DNSPs to provide a more recent demand forecast. This more recent forecast was based on four and six year histories to summer 2006–07. However, the more recent

380 NIEIR, p. 30.
381 MMA *Integral Energy's customer number and energy forecasts*, confidential, p. 5.

forecast was not used by EnergyAustralia in constructing its area plans and capex program as it was not available at the time it would have been required.[382] Analysis of the statistical confidence level difference between the two forecasts was not undertaken as the adjusted method did not affect proposed capex in any case. However, in reviewing EnergyAustralia's methodology MMA noted that on balance, EnergyAustralia's approach was reasonable.

EnergyAustralia stated that it investigated the underlying causes of lower than forecast peak demand in 2006–07, to the extent possible (constrained by the availability of explanatory data). According to EnergyAustralia, relevant factors included economic activity, the number of customers connected to the network and the proportion of customers with and without air-conditioning.[383] EnergyAustralia also noted that the lack of daily or even seasonal data pertaining to the trends in the drivers of electricity consumption limits the degree of investigation that can be undertaken.

While the actual global summer peak demand in 2006–07 was 7.2 per cent lower than the previous year (10 per cent or 570MW below the 50 per cent PoE forecast), the weather corrected summer peak demand was 2.1 per cent higher. This followed stronger growth in the previous year of 4.3 per cent and was followed by 3.0 per cent growth in 2008.[384] EnergyAustralia also provided the following information concerning the estimated contribution to the weather-corrected global peak demand of each customer class in summer 2005–06, 2006–07 and 2007–08 respectively:[385]

- residential customers with air conditioning - 28%, 30%, 31%
- residential customers without air conditioning - 8%, 7%, 7%
- non-residential (business) customers - 64%, 63%, 62%.

The information provided by EnergyAustralia appears to confirm that the lower than forecast peak demand in 2006–07 was largely due to mild weather. The AER notes that once weather correction is applied, the relative contributions by customer class for 2006–07 are not out of line with recent trends.

In relation to the EUAA's question regarding 2007–08 actual demand for Botany Zone, EnergyAustralia stated that the 'maximum demand recorded for Botany in summer 2007/08 was 38.9MVA at 1330hrs on 31st January 2008. The forecast load shown in table 4.2 of the regulatory proposal for 2007/08 was 42.1MVA and the secure capacity was 36.9MVA.'[386] EnergyAustralia also stated that:[387]

> Following the forecast based on 2006/07 we identified that Botany zone was over firm rating and initiated load transfers to neighbouring Maroubra and Mascot

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382 EnergyAustralia noted that latest forecast information in the RIN template only became available just as the proposal was submitted. Therefore the latest forecast information was not used as the basis for the proposal as there were many months worth of system analysis and option studies required prior to the compilation of the proposal.

383 EnergyAustralia, email response to demand forecasting questions, 22 October 2008.

384 EnergyAustralia, email response to demand forecasting questions, 22 October 2008.

385 EnergyAustralia, email response to demand forecasting questions, 22 October 2008.

386 EnergyAustralia, email response to demand forecasting questions, 22 October 2008.

387 EnergyAustralia, email response to demand forecasting questions, 22 October 2008.

zones. By summer 2007/08 approx 1MVA worth of load had already been transferred away with more to follow. Note that the load in summer 2005/06 (39.8MVA) is higher than the actual load in 2006/07 (37.7MVA) further highlighting that 2006/07 was a low load season (no transfers from Botany occurred in this period).

The AER notes the EUAA's submission that it should carry out a robust analysis of the accuracy of forecasts in the current and previous regulatory periods, and consider carrying out its own independent demand forecasts. As part of the review of demand forecasts, the AER and MMA reviewed the DNSPs' 2004 forecasts for the current regulatory control period and actual results to date. The AER decided not to produce independent demand forecasts for each DNSP's network for the next regulatory control period, electing instead to focus on reviewing the forecast methodologies employed to ensure that the forecasts were developed using robust, reasonable methods. MMA and the AER also considered the key drivers behind the forecasts, and closely analysed any variations from historical trends within the forecasts.

6.5 AER conclusion

6.5.1 Country Energy

The AER considers Country Energy's maximum demand forecast methodology and forecasts provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the transitional chapter 6 rules.

The AER's draft decision is to reject the energy and customer number forecasts provided within Country Energy's regulatory proposal, under clause 6.12.1(10) of the transitional chapter 6 rules, as it considers that the forecasts are outdated and therefore are inappropriate inputs into the AER's PTRM.

The AER considers Country Energy's energy and customer number forecast methodologies reasonable, however, considers that the forecasts in its regulatory proposal should be updated to take into account the most recent energy sales and customer numbers data, once audited data for regulatory year 2007–08 becomes available. Accordingly, the AER requests that revised energy and customer number forecasts be submitted to the AER for consideration in its final determination. The revised forecasts are necessary for the AER to make its decision on appropriate amounts, values or inputs in the AER's final determination for the next regulatory control period, under clause 6.12.1(10) of the transitional chapter 6 rules.

The revised energy forecast is to use the audited energy data for 2007–08 as a starting point, which should then be grown at the rate applied within the original NIEIR base–case energy forecast in Country Energy's regulatory proposal. The new data is to be weather corrected and allocated according to the methodology applied in generating the original energy forecast.

The new energy forecast should incorporate a revised customer number forecast, which is to use actual customer numbers as at 30 June 2008 as the starting point for the forecast, then escalated at the NIEIR recommended base–case forecast for the remaining years of the next regulatory control period.

The AER requests that Country Energy provide the revised energy and customer number forecasts as an updated version of the Forecast Sales Quantities table within the Input sheet of its post tax revenue model, by COB on 20 February 2009.

6.5.2 EnergyAustralia

The AER considers EnergyAustralia's maximum demand forecast methodology and forecasts provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the transitional chapter 6 rules.

The AER's draft decision is to reject the energy and customer number forecasts provided within EnergyAustralia's regulatory proposal, under clause 6.12.1(10) of the transitional chapter 6 rules, as it considers that the forecasts are outdated and therefore are inappropriate inputs into the AER's PTRM.

The AER considers the revised customer number forecast provided by EnergyAustralia on 29 October 2008 is an appropriate input into the PTRM, and accepts it under clause 6.12.1(10) of the transitional chapter 6 rules.

The AER considers EnergyAustralia's energy forecasting methodology is reasonable, however, considers that the revised energy forecast (which were provided to the AER on 29 October 2008) should be updated to take into account the most recent energy sales data, once audited data for regulatory year 2007–08 becomes available. Accordingly, the AER requests that a revised energy forecast be submitted to the AER for consideration in its final determination. The revised forecasts are necessary for the AER to make its decision on appropriate amounts, values or inputs in the AER's final determination for the next regulatory control period, under clause 6.12.1(10) of the transitional chapter 6 rules.

The revised energy forecast is to use the audited energy data for 2007–08 as a starting point, which should then be grown at the rate applied within the original energy forecast in EnergyAustralia's regulatory proposal. The new data is to be weather corrected and allocated according to the methodology applied in generating the original energy forecast. The new energy forecast should incorporate the revised customer number forecast provided to the AER on 29 October 2008. The AER requests that EnergyAustralia provide this revised forecast as an updated version of the Forecast Sales Quantities table within the Input sheet of its post tax revenue model, by COB on 20 February 2009..

6.5.3 Integral Energy

The AER considers that the maximum demand forecast within Integral Energy's regulatory proposal does not provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the transitional chapter 6 rules.

The AER considers that the revised maximum demand forecast provided by Integral Energy on 29 August 2008 represents a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the transitional chapter 6 rules. The AER's draft decision is to accept Integral Energy's revised maximum demand forecast.

The AER's draft decision is to reject the energy and customer number forecasts provided within Integral Energy's regulatory proposal, under clause 6.12.1(10) of the transitional chapter 6 rules, as it considers that the forecasts are outdated and therefore are inappropriate inputs into the AER's PTRM.

The AER considers the revised customer number forecast provided by Integral Energy on 31 October 2008 is an appropriate input into the PTRM, and accepts it under clause 6.12.1(10) of the transitional chapter 6 rules.

The AER considers Integral Energy's revised energy forecasting methodology is reasonable, however, considers that the revised energy forecasts (which were provided to the AER on 31 October 2008) should be updated to take into account the most recent energy sales data, once audited data for regulatory year 2007–08 becomes available. Accordingly, the AER requests that a revised energy forecast be submitted to the AER for consideration in its final determination. The revised forecasts are necessary for the AER to make its decision on appropriate amounts, values or inputs in the AER's final determination for the next regulatory control period, under clause 6.12.1(10) of the transitional chapter 6 rules.

The revised forecast is to use the audited energy data for 2007–08 as a starting point, which should then be grown at the rate applied within the original energy forecast in Integral Energy's regulatory proposal. The new data is to be weather corrected and allocated according to the methodology applied in generating the original energy forecast. The new energy forecast should incorporate the revised customer number forecast provided to the AER on 31 October 2008. The AER requests that Integral Energy provide this revised forecast as an updated version of the Forecast Sales Quantities table within the Input sheet of its post tax revenue model, by COB on 20 February 2009.

6.6 AER draft decision

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the AER has decided that the other appropriate amounts, values or inputs with respect to energy consumption and customer number forecasting are to be provided by Country Energy as a revised energy delivered forecast, within the input sheet of Country Energy's post tax revenue model for standard control services, by COB on 20 February 2009.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the AER has decided that the other appropriate amounts, values or inputs with respect to energy consumption forecasting are to be provided by EnergyAustralia as a revised energy delivered forecast, within the input sheet of EnergyAustralia's post tax revenue model for standard control services, by COB on 20 February 2009.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the AER has decided that the other appropriate amounts, values or inputs with respect to customer number forecasting for EnergyAustralia are those that were provided to the AER on 29 October 2008, and that are contained in table 6.7 of the draft decision.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the AER has decided that the other appropriate amounts, values or inputs with respect to energy consumption forecasting are to be provided by Integral Energy as a revised energy delivered forecast, within the input sheet of Integral Energy's post tax revenue model for standard control services, by COB on 20 February 2009.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the AER has decided that the other appropriate amounts, values or inputs with respect to customer number forecasting for Integral Energy are those that were provided to the AER on 31 October 2008, and that are contained in table 6.8 of the draft decision.

7 Forecast capital expenditure

7.1 Introduction

This chapter sets out the AER's conclusions on forecast capex allowances for the NSW DNSPs for the next regulatory control period. It also:

- discusses the framework the AER has applied in assessing each proposal
- discusses the outcomes of the current regulatory control period
- provides a general overview of the proposals
- lists comments made by stakeholders on the proposals
- summarises the AER's main considerations and responses to stakeholder comments.

The AER's conclusions and the estimate of forecast capex allowances for each DNSP during the next regulatory control period are set out in section 7.9 of this chapter. A complete explanation of the NSW DNSPs' proposals and the AER's considerations for each are outlined in appendices K, L, and M of this draft decision. This chapter is to be read in conjunction with these appendices.

7.2 Regulatory requirements

Clause 6.12.1(3) of the transitional chapter 6 rules provides that the AER must make a decision to accept, or reject and form its own estimate of, the total of forecast capex included in a building block proposal of each NSW DNSP in accordance with the capital expenditure objectives (capex objectives), the capital expenditure criteria (capex criteria) and the capital expenditure factors (capex factors) outlined in clause 6.5.7 of the transitional chapter 6 rules.

7.2.1 Capex objectives

Clause 6.5.7(a) of the transitional chapter 6 rules provides that a DNSP must include the total forecast capex for the regulatory control period in order to achieve the following capex objectives:

> (1) meet or manage the expected demand for standard control services over that period;
>
> (2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;
>
> (3) maintain the quality, reliability and security of supply of standard control services;
>
> (4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

7.2.2 Capex criteria and factors

Clause 6.5.7(c) of the transitional chapter 6 rules also provides that the AER must accept the capex forecast included in a NSW DNSP's regulatory proposal if it is satisfied that the total of the capex forecast for the regulatory control period reasonably reflects:

(1) the efficient costs of achieving the capex objectives

(2) the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the capex objectives

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.[388]

In making this assessment the AER must have regard to the capex factors contained in clause 6.5.7(e) of the transitional chapter 6 rules:

(1) the information included in or accompanying the building block proposal

(2) submissions received in the course of consulting on the building block proposal

(3) analysis undertaken by or for the AER and published before the distribution determination is made in its final form

(4) benchmark capex that would be incurred by an efficient DNSP over the regulatory control period

(5) the actual and expected capex of the DNSP during any preceding regulatory control periods

(6) the relative prices of operating and capital inputs

(7) the substitution possibilities between opex and capex

(8) whether the total labour costs included in the capex and opex forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period

(9) the extent the forecast of required capex of the DNSP is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms

(10) the extent the DNSP has considered, and made provision for, efficient non–network alternatives.

Clause 6.5.7(d) of the transitional chapter 6 rules states that, if the AER is not satisfied that a DNSP's forecast capex reasonably reflects the capex criteria, then the AER must not accept the forecast capex in a building block proposal. If the AER does not accept the total forecast capex proposed by a DNSP, clause 6.12.1(3)(ii) requires the AER to include in its draft decision:

[388] The capex criteria.

> …an estimate of the total of the DNSP's required capex for the regulatory control period that the AER is satisfied reasonably reflects the capex criteria, taking into account the capex factors.

7.3 AER approach to assessment

In determining whether the capex forecast included in each of the NSW DNSPs' regulatory proposals reasonably reflects the capex criteria, having regard to the capex factors, the AER's approach to assessment has been to determine and examine whether:

- their governance frameworks, capex policies and procedures are likely to result in investment decisions, on which the capex proposals are based, are consistent with the capex objectives
- the methods and assumptions used to develop each capex proposal, including demand forecasts and estimates of unit costs, are robust and reflect a realistic expectation of the demand forecasts and cost inputs required to achieve the capex objectives
- estimates of real cost escalators and their application reflect a reasonable expectation of input cost forecasts
- the projects and programs that form part of the regulatory proposals generally reflect the capex criteria, including with respect to their scope, timing and costs
- the capex programs are deliverable and are therefore commensurate with what a prudent DNSP would require to achieve the capex objectives.

Overall these considerations are intended to assist the AER determine whether it is satisfied that the forecast capex of each DNSP reasonably reflects the capex criteria listed in clause 6.5.7(c) of the transitional chapter 6 rules.

This approach is similar to that applied by the AER to electricity transmission network service providers (TNSPs) under chapter 6A of the NER, which largely mirror the requirements in the transitional chapter 6 rules. However, the application of this approach to the NSW DNSPs is different as the characteristics of distribution networks, specifically the larger number of individual projects and programs, means it is not possible or practical for the AER undertake a more detailed review. Specifically:

- while a wide range of the NSW DNSPs' projects and programs were reviewed by the AER and its consultants, the AER's overall assessment has placed less reliance on individual project reviews, in contrast to its approach for TNSPs
- due to the limitations of reviewing a large number of projects in detail, relatively more reliance has been placed on a review of the NSW DNSPs' policies and procedures and the underlying assumptions such as demand forecasts and unit costs estimates, to gauge the reasonableness of the proposed capex allowances
- with assistance from its consultant, the AER has considered more general factors (e.g. trends in asset age, faults etc) and methods (e.g. expenditure modelling) in examining investment proposed at lower voltages in the network

- where appropriate, the AER and its consultants have examined departures from identified trends in historical expenditure

- owing to the similarities in their proposals, the AER has compared and contrasted the NSW DNSPs' forecast changes in generic input costs.

7.4 Current period outcomes

This section summarises the expenditure outcomes of the NSW DNSPs with respect to the allowances set by IPART and the ACCC, to identify whether any cost drivers were not identified for the current regulatory control period that should be recognised when examining the proposals for the next regulatory control period.

In aggregate, the NSW DNSPs are expected to exceed their combined regulated capex allowance by approximately $1271 million ($2008–09) or 19 per cent of the allowances set by IPART and the ACCC.[389] This is shown in table 7.1 and Figure 7.1. Around 94 per cent of the total overspend is attributable to EnergyAustralia and Country Energy.

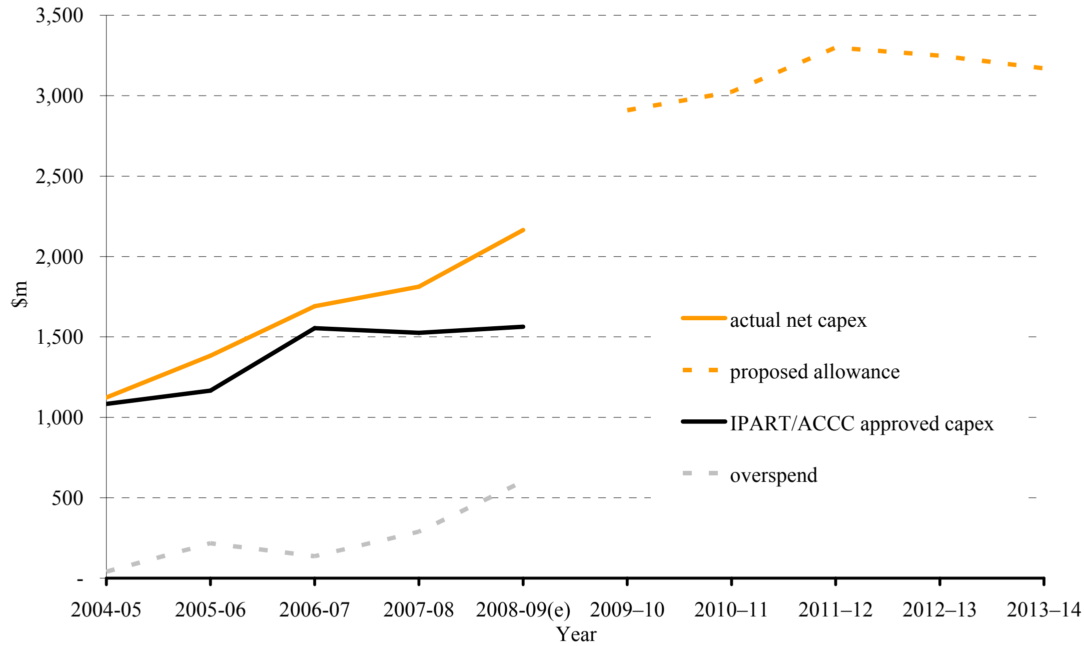
Table 7.1: Capex outcomes, combined NSW DNSPs– 2004–09 ($m, 2008–09)

	2004–05	2005–06	2006–07	2007–08 (estimate)	2008–09 (estimate)	Total
Regulatory allowance	1083.5	1166.0	1555.0	1524.7	1563.1	6892.3
Actual net capex	1123.1	1383.3	1690.9	1812.8	2164.9	8174.9
Overspend	39.6	217.3	135.9	288.0	601.9	1282.6

Source: Country Energy, EnergyAustralia, Integral Energy: RIN pro forma 2.2.1, converted to real terms using ABS inflation data.

[389] IPART, *NSW Electricity Distribution Pricing Final Determination*; and ACCC, *NSW and ACT transmission network revenue cap EnergyAustralia 2004–05 to 2008–09*, April 2005.

Figure 7.1 NSW DNSPs combined actual and proposed capex ($m real 2008–09)



Source: Country Energy, EnergyAustralia, Integral Energy: RIN pro forma 2.2.1, converted to real terms using ABS inflation data.

The reasons provided by the NSW DNSPs for the overspend include:[390]

- unit rates for estimating construction costs approved by IPART were not reflective of market conditions
- the allowances approved by the ACCC and IPART (including for Australian Inland) tending to be at the lower end of the plausible range, or generally insufficient
- higher than anticipated expenditure on reliability improvements, reactive replacement and augmentation, as well as on non–system assets.

The AER has not examined the merits of these claims in detail. However, in terms of the implications for its review of forecast capex, the AER observes that:

- increases in certain commodity prices and labour costs were likely to be a material contributor to the overspends, particularly during the latter part of the current regulatory control period. Expected price movements for the next regulatory control period have been incorporated into the DNSPs' capex proposals
- IPART and the ACCC's determinations were made using the information provided and assessed as reasonable at the time. In this context Wilson Cook considers the NSW DNSPs have presented:

[390] Country Energy, *Regulatory proposal*, pp. 70–72,
EnergyAustralia, *Regulatory proposal*, pp. 98–99,
Integral Energy, *Regulatory proposal*, p. 47.

> …better-prepared cases in support of the expenditure proposals this time, compared with the cases put forward for assessment in NSW for the previous review[391]

- the AER also notes that EnergyAustralia has indicated it has taken steps to improve its forecasting accuracy.[392] The AER also expects Country Energy has improved its recording of asset condition and other relevant data as it incorporates and refines the reporting systems adopted during its recent merger with Australian Inland Energy.

The AER did not consider it appropriate to request a response from IPART on these matters, as suggested by the Energy Users Association of Australia (EUAA) (discussed below), as its considerations would not be relevant in the AER's examination of the capex forecasts for the next regulatory control period.

In conclusion, the AER considers that the major reasons for the observed overspend are known to the NSW DNSPs and is satisfied these reasons have been taken into account when developing their current regulatory proposals. This improves the likelihood that the DNSPs have presented a complete case on which the AER is able to assess the proposals against the capex criteria.

7.5 NSW DNSP proposals

The NSW DNSPs proposed a total forecast capex requirement of $15 620 million ($2008–09) for the next regulatory control period. The amounts proposed by each business are set out in table 7.2. Figure 7.2 illustrates the combined proposed capex of the businesses in comparison to their actual capex over the current regulatory control period.

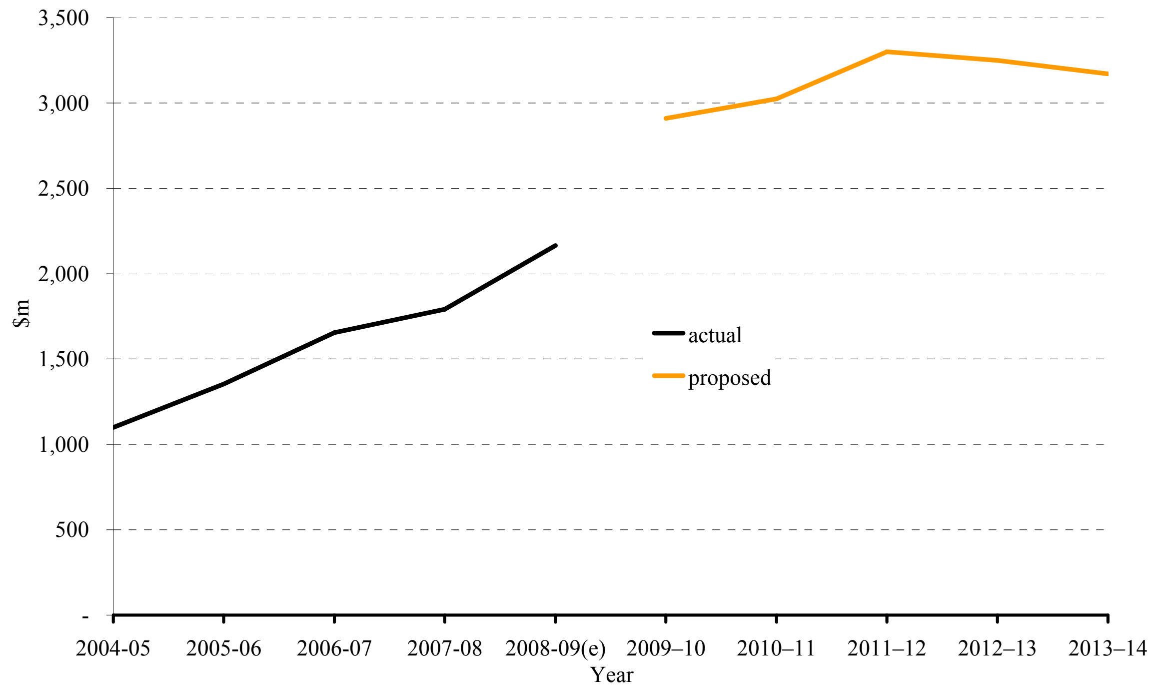
Table 7.2: Proposed capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy[a]	752.0	779.0	806.0	822.0	849.5	4008.4
EnergyAustralia	1584.9	1603.3	1877.8	1830.3	1763.2	8658.5
Integral Energy	573.9	641.5	610.4	582.5	544.3	2952.7

Source: Country Energy, EnergyAustralia, Integral Energy: RIN pro forma 2.2.1.
(a) Values reflect Country Energy's subsequent correction (reduction) to fleet expenditure from RIN values.

391 Wilson Cook, volume 1, p. ix.
392 EnergyAustralia, *Regulatory proposal*, p. 99.

Figure 7.2: Actual and proposed capex, all businesses ($m, 2008–09)



Source: Country Energy, EnergyAustralia, Integral Energy: RIN pro forma 2.2.1, historical data converted to real 2008–09 dollars.

The $15 620 million of capex proposed by the NSW DNSPs is 94 per cent above the $8065 million spent in the current regulatory control period. The NSW DNSPs commonly identify the following justifications for this increase:

- growth in peak demand
- assets that are ageing and declining in their condition and serviceability
- ongoing investment to adhere to the planning and performance requirements in the NSW Government's Design, Reliability and Performance (DRP) licence conditions, some of which become gradually more stringent over the next regulatory control period.

For Country Energy, the cost impact of the recently introduced licence requirements is large and reflected in its proposed reliability capex and augmentation capex programs.

EnergyAustralia has proposed a significant replacement program for its 33kV gas and 132kV oil-filled subtransmission cables to address ongoing network performance issues. It has also identified a need to undertake investment in its 11kV network which was deferred from the current regulatory control period due to resource constraints.[393]

[393] EnergyAustralia, *Regulatory proposal*, p. 99.

A key driver of Integral Energy's capex program is its growth in peak demand of 3.6 per cent per year. This is occurring even though the growth in new connections is slowing, resulting in a deteriorating load factor.[394]

7.6 Submissions

The AER received submissions from the Energy Markets Reform Forum (EMRF), the Public Interest Advocacy Centre Ltd (PIAC), the EUAA and two submissions from EnergyAustralia.

The submissions from the EMRF, PIAC and the EUAA raised concerns regarding the following aspects of the NSW DNSPs' proposals:

- **Deliverability**—Doubts were expressed that the NSW DNSPs could deliver the large capex programs proposed (including at the same time) in the context of the current constrained supply conditions, leading to a risk of customers paying for proposed network upgrades that can not be completed.[395]

- **Demand management and timing of investment**—the submissions sought assurances that the NSW DNSPs had undertaken sufficient analysis of the potential benefits and risk impact of deferring their proposed investments, including through demand management and in the context of expected decreases in input prices. These concerns were also raised in the context of the significant price increases that would result from the proposals.[396]

- **Veracity of investment decisions**—

  - the EMRF requested advice from the AER on ways to ensure that the NSW DNSPs are not replacing assets before the end of their useful lives, and ensure they undertake financial analysis to identify replacement needs from a commercial (rather than physical) point of view[397]

  - the EMRF also undertook analysis for each business with respect to forecast demand growth, finding that the capex proposed was in excess of between 10 per cent (for Integral Energy) and 50 per cent (for EnergyAustralia) of that implied by increases in demand[398]

  - the EUAA sought assurances that the expenditures are not simply justified on a needs basis but in terms of whether the investments proposed are efficient. It further suggested that performance measures be provided to indicate that the NSW DNSPs are operating at the highest possible level of efficiency[399]

394 Integral Energy, *Regulatory proposal*, p. 65.
395 EMRF, p. 10; EUAA, p. 13–14; PIAC, p. 3.
396 EMRF, pp. 18–20; EUAA, pp. 17–18; PIAC, p. 2.
397 EMRF, pp. 23–24.
398 EMRF, pp. 15–18.
399 EUAA, p 15.

- the PIAC requested assurances that expenditure proposed for reliability reasons was not associated with requirements that were in excess of the NSW DNSPs' mandatory licence requirements.[400]

- **Input cost escalation**–
  - the EMRF noted that construction wages are decreasing relative to average wages, and that recent data indicate that, while the prices for some material inputs could increase, some are decreasing[401]
  - the EUAA suggested that the AER seek an independent analysis of the escalators and assess the ability of the NSW DNSPs to efficiently manage input cost increases, as such increases would be managed by businesses operating in a competitive market.[402]

The EUAA suggested the AER undertake a thorough examination of previous determinations and current period outcomes to understand why and how such high capex requirements have accumulated.[403] It also suggested the AER seek a public and detailed response from IPART to the NSW DNSPs' regulatory proposals specifically addressing the validity of their claims regarding the insufficient allowances in IPART's 2004 determination.[404]

EnergyAustralia's first submission addressed concerns raised at the AER's public forum regarding the deliverability of its capex program. It mentioned that it has undertaken a smoothing analysis of its proposed expenditure and restated elements of its proposal relating to its staffing and outsourcing arrangements.[405]

EnergyAustralia's second submission responded to the submissions made by other stakeholders.[406] In general, it listed specific stakeholder concerns regarding the justifications and deliverability of its capex proposal, potential deferrals, non–network alternatives and its replacement decisions, and in response refers to various sections and attachments of its regulatory proposal.

7.7 Consultant review

The AER engaged Wilson Cook to provide an independent assessment of the efficiency and appropriateness of the capex proposals of the NSW DNSPs, as well as ActewAGL.[407]

400 PIAC, p. 3.
401 EMRF, pp. 19–22.
402 EUAA, p. 14.
403 EUAA, p. 11.
404 EUAA., p. 22.
405 EnergyAustralia, *Response to AER's request for submissions on NSW DNSPs' regulatory proposals*, 8 August 2008, p. 2.
406 EnergyAustralia, *Response to request for submissions*, p. 2.
407 The details of Wilson Cook's assessment of ActewAGL and the AER's associated considerations are detailed in AER, *Draft decision Australian Capital Territory- distribution determination 2009–10 to 2013–14*, November 2008.

In assessing the appropriateness of the proposals, Wilson Cook considered the following key factors:[408]

- prudence and efficiency of the proposed expenditures[409]
- external factors and obligations that were material to the proposals and in particular those that changed from the current to the next regulatory control period
- expenditure projections for consistency with the demand forecasts accepted by the AER
- unit costs, escalation rates and methodologies for materials cost escalation
- expenditure drivers including the need to address demand growth, ageing assets and safety and environmental issues
- appropriateness and consistent application of policies and procedures.

In reviewing the capex proposals Wilson Cook identified several issues common to the DNSPs, including:[410]

- considerable increases in costs from the current regulatory control period due to increases in materials costs, and to a lesser extent, in labour costs
- the cost of newly mandated licence conditions
- the need to replace ageing assets at a faster rate
- increased IT expenditure.

Overall, Wilson Cook concluded that the capex proposed by each of the NSW DNSPs was prudent and efficient. Wilson Cook identified specific issues such as Integral Energy's replacement expenditure and the non–system capex proposed by Country Energy. In these instances Wilson Cook recommended reductions in the proposed capex allowance. Its conclusions are discussed in more detail below.

Without proposing further reductions to the proposed capex allowances Wilson Cook made other observations regarding the NSW DNSPs' capex proposals:

- while particular items of expenditure might be justified, the optimality of their timing was more difficult to gauge[411]
- regarding assumed unit construction costs:

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408 Wilson Cook, volume 1, pp 7–12

409 Wilson Cook, volume 1, p. 9. Where Wilson Cook has considered there was an appropriate balance between the factors it considers comprises 'prudence' and 'efficiency', it has concluded in its report that the expenditure is "reasonable".

410 Wilson Cook, volume 1, p. 28.

411 Wilson Cook, volume 1, p. 14.

    - the procurement of materials and equipment is bid competitively
    - the designs used appeared reasonable
    - various high level reviews of the cost of construction of new assets, undertaken by engineering advisers to the NSW DNSPs, had generally found that the construction costs assumed by the NSW DNSPs in their proposals were reasonable[412]

- it was not able to say definitively that the NSW DNSPs' own capital costs (as opposed to those related to goods and services that are procured competitively) are efficient in all respects, although it accepted them as sufficiently so for the purpose of its review[413]
- it was not possible to accurately gauge how effective the NSW DNSPs' internal resources and processes were at the implementation of this work. It considered, on balance, and in light of its experience, that the installed cost of new assets was reasonable for the purpose of this review.[414]

The capex allowances resulting from Wilson Cook's recommended adjustments are provided in table 7.3.

Table 7.3: Wilson Cook's recommended forecast capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	724	757	784	798	823	3884
EnergyAustralia	1584	1603	1878	1830	1762	8658
Integral Energy	574	639	607	578	525	2924

Source: Wilson Cook, volume 2 (table 4.1 and 8.1), volume 3 (table 7.3 and 8.1) and volume 4 (p. 27, tables 4.1 and 8.2).

Wilson Cook's specific comments with respect to the NSW DNSPs' capex proposals are outlined in appendices K, L and M of this decision.

7.8 AER issues and considerations

7.8.1 Policies and procedures

7.8.1.1 DNSP proposals

Each DNSP has a variety of policies, plans and procedures which are used to identify investment needs (including from long term and strategic viewpoints, and also non–network solutions such as demand management), formulate appropriate investment solutions, scope and estimate appropriate costs and monitor expenditures with respect to

412 Wilson Cook, volume 1, pp. 14–15.
413 Wilson Cook, volume 1, p. 29.
414 Wilson Cook, volume 1, p. 15.

budgeted or approved amounts. These elements are supported by various feedback loops and communication mechanisms to ensure decisions are coordinated and refined in light of experience.

The key documents provided with the NSW DNSPs' proposals in terms of asset management strategies are investment plans which largely reflect the consolidation and output of various smaller planning documents and procedures, which are generally reviewed on a periodic basis.

Country Energy's Network Asset Management Plan consolidates various sub-plans for specific investment types (e.g. augmentation, renewal).

EnergyAustralia produced a series of investment plans which incorporate investment needs identified at the driver level. The largest of these are its three transmission area plans and 25 subtransmission area plans which outline investment solutions for a geographically defined area. It also has a series of plans by voltage type (e.g. 11kV and low voltage) and specific purpose (e.g. replacement and duty of care).

Integral Energy's network planning framework is represented in its 10 year Strategic Asset Management Plan. The strategic asset management plan represents a single coordinated asset management plan which documents how Integral Energy's individual network capital and maintenance plans support strategic outcomes.

7.8.1.2 Consultant review

Wilson Cook reviewed the documents which underpinned the NSW DNSPs' investment and operational decisions, and examined them in their reflection of:[415]

- modern industry practice
- appropriate basis for project selection (e.g. establishment of investment need, identification of alternatives, estimating costs, selection of least cost alternative and optimal timing)
- consistency with long term plans.

Wilson Cook did not conclude that the policies and procedures were unsuitable or unreasonable.[416]

7.8.1.3 AER considerations

Overall the AER considers that the documented policies and procedures provided by the NSW DNSPs outline a sound framework for the facilitation of investment which is generally aimed at achieving the capex objectives listed in clause 6.5.7(a). The DNSPs' forecast capex proposals are more likely to reflect efficient costs to the extent they have been based on these policies and procedures. The AER has considered whether this is the case in determining whether it is satisfied the capex proposals reflect the capex criteria.

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[415] Wilson Cook, volume 1, p. 11.
[416] Wilson Cook, volume 1, p. 12.

During the review process the AER was able to gain an understanding of the role of each DNSP's governance arrangements and the process by which investment needs were identified and incorporated into the broader asset management plans. As noted by Wilson Cook, where concerns were raised with the expenditure proposals, these tended to be due to a lack of specific details rather than a problem with the NSW DNSPs' generic practices or policies. In a general sense, these findings support the prudence and efficiency of the NSW DNSPs' capex proposals.

7.8.2 Methods and assumptions

7.8.2.1 DNSP proposals

Demand forecasts and methodologies

Country Energy engaged the National Institute of Economic and Industry Research (NIEIR) to develop its maximum demand, energy and customer number forecasts, as well as to give advice on the forecasts of key economic parameters that may influence electricity demand.[417] Country Energy stated that it carried out further analysis of NIEIR's projections to develop its final winter maximum demand forecast.[418]

EnergyAustralia engaged CRA International (CRA) to provide an independent assessment of the reasonableness of its demand forecasting process.[419]

Integral Energy also engaged CRA to review all material underlying assumptions and methodologies used in developing its demand forecasts. CRA found Integral Energy's forecasts of maximum demand, energy consumption and corresponding growth rates to be reasonable for the purposes of developing its capex proposal.[420] Further details on the NSW DNSPs' proposed demand forecasts are provided in chapter 6.

Unit cost assumptions

The NSW DNSPs engaged consultants to develop independent unit cost benchmarks to compare and evaluate the input costs which formed the basis of their capex proposals.

Country Energy commissioned Sinclair Knight Merz (SKM) to update its asset unit rates applied in its 2002 asset valuation to 2007 terms, however it did not rely on this work in developing its unit costs. SKM identified various reasons why Country Energy's unit rates were much higher than those incorporated into the previous IPART determination. Country Energy has employed its internal cost estimation system in developing its capex proposal, which draws on a frequently updated database of historic actual unit costs for various works.[421]

EnergyAustralia provided a review conducted by SKM of its substation cost estimates. SKM produced detailed cost estimates of three substations based on scoping documents provided by EnergyAustralia and high level cost estimates for a further eighteen

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417 Country Energy, *Regulatory proposal*, p. 84.
418 Country Energy, *Regulatory proposal*, p. 84. Country Energy provided additional information to the AER on 14 July 2008, outlining changes it made to NIEIR's winter maximum demand forecast to update the forecast to account for recently available winter peak demand data.
419 EnergyAustralia, *Regulatory proposal*, pp. 42–45.
420 Integral Energy, *Regulatory proposal*, p. 62.
421 Country Energy, *Regulatory proposal*, p. 86.

substations. As detailed in appendix L, SKM found EnergyAustralia's project estimates (excluding civil works) were all within 20 per cent and on average were 8 per cent higher than its own estimates.

Integral Energy commissioned PB who evaluated a sample of its proposed projects and, while noting some concerns with the estimation process, determined both costs and unit rates to be prudent and reasonable.[422] PB also concluded that Integral Energy's proposed cost estimates for its proposed growth-related capex appeared efficient and reasonable.[423]

7.8.2.2 Consultant reviews

The AER requested Wilson Cook to develop independent forecasts of unit costs in advance of receiving the NSW DNSPs' proposals. Wilson Cook stated this was not possible, as the NSW DNSPs used various methods for cost estimation, relying generally on the reported cost of completed work, internal costing programmes or independent review and not on unit costs of a type that could be compared. It noted that unit costs for substation installations were prone to a significant degree of variation, but may be able to be compared:

> …but only in respect of well-defined building blocks, and with other DNSPs using similar designs, and excluding site-specific costs.[424]

Notwithstanding these qualifications, Wilson Cook noted that the majority of capex is generally procured through competitive processes and so concluded that the DNSPs reported costs of recently completed work were efficient, however noted that there may still be scope for efficiency improvement.[425]

Wilson Cook did not verify that the demand forecasts assumed by the NSW DNSPs for planning purposes as these were reviewed separately by the AER. It did check (in selected cases) that the NSW DNSPs' growth capex proposals matched the levels of demand in their planning documents.[426]

As detailed in chapter 6, the AER engaged McLennan Magasanik Associates (MMA) to review the demand forecasts submitted by EnergyAustralia and Integral Energy. The AER reviewed Country Energy's forecasts in-house, and by reference to MMA's review. The AER found that Country Energy's maximum demand forecasts provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the transitional chapter 6 rules.

While MMA found EnergyAustralia's maximum demand forecasts to be reasonable, it identified several concerns with Integral Energy's maximum demand forecasting methodology which resulted in the AER requesting a revised maximum demand forecast

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422 PB, *Review of assumptions underpinning capital and operating expenditure forecasts*, May 2008, p. 29.
423 PB, p. 48.
424 Wilson Cook, volume 1, p. 10.
425 Wilson Cook, volume 1, p. 10.
426 Wilson Cook, volume 1, p. 9.

for the next regulatory control period. The AER also requested that a revised capex forecast be prepared on the basis of the revised maximum demand forecast.[427]

7.8.2.3 AER considerations

Demand forecasts and methodologies

The AER's consideration of the NSW DNSPs' demand forecasts and forecast methodologies is outlined in chapter 6.

The AER considers Country Energy's and EnergyAustralia's maximum demand forecast methodologies and forecasts provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in clauses 6.5.7(a)(1); 6.5.7(c)(3); 6.5.6(a)(1); and 6.5.6(c)(3) of the transitional chapter 6 rules.

In the course of its review, the AER requested that Integral Energy address a number of methodological concerns identified by its consultant, MMA, and prepare a revised maximum demand forecast consistent with recent trends in maximum demand and corresponding macroeconomic drivers.[428] Notwithstanding MMA's recommendations concerning further improvements that Integral Energy could make to its forecasting processes, the AER considers Integral Energy's revised maximum demand forecasts provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the transitional chapter 6 rules.[429]

Unit cost assumptions

The AER notes Wilson Cook's comments regarding the practice of comparing unit cost estimates of different types of assets, and the resulting qualifications to its recommendations. However, the AER must determine whether it is satisfied that the expenditure proposed by the NSW DNSPs reasonably reflects the efficient costs of achieving the capex objectives required by a prudent operator and are a realistic expectation of input costs under the capex criteria in clause 6.5.7(c). For this reason it has carefully considered the information provided by the NSW DNSPs, including the reports of their consultants.

PB noted that Integral Energy's replacement costs for transformers were on the high side of its benchmark and Integral Energy's own historic costs, although was informed that this reflected the use of the latest contract prices and installation costs.[430] In combination with this, PB implied that some cost estimates may not be objectively verifiable as they are sourced from experts. PB concluded, however, that it did not find any evidence to suggest that Integral Energy's costs were unreasonable.[431]

While the AER has some reservations regarding the scope for improvement in Integral Energy's estimation processes as identified by PB, the AER is generally satisfied that Integral Energy's unit costs reflect a realistic expectation of efficient cost inputs. In

427 AER, letter to Integral Energy, 11 August 2008.
428 AER, letter to Integral Energy, 11 August 2008.
429 Integral Energy, response to 11 August 2008 letter from the AER on Integral Energy's Maximum Demand forecast for the 2009–14 regulatory period, 29 August 2008.
430 PB, p. 61.
431 PB, p. 59.

particular, the differences between the unit costs developed by PB (which it regards as a credible and independent source) and Integral Energy appear to be limited to cases where Integral Energy has used latest historical costs, which reflects good industry practice.

Similarly, the AER is reasonably satisfied that the unit cost estimates used by Country Energy reflect efficient cost inputs as they are sourced from a database of updated historical costs, which for material projects, reflect the outcomes of competitive tendering.

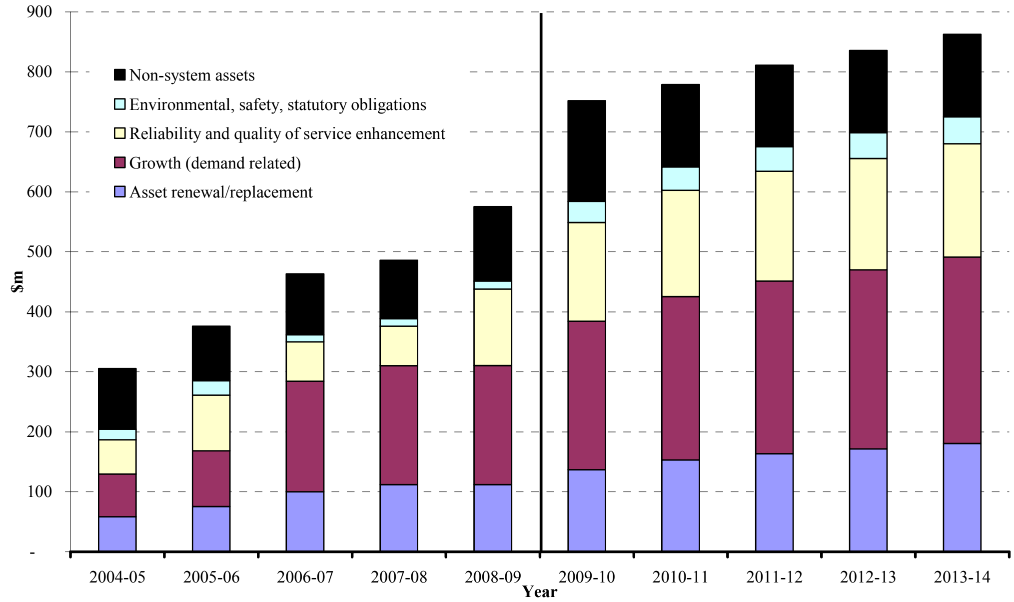
As detailed in appendix L, the AER has given careful consideration to SKM's review of EnergyAustralia's substation cost estimates and considers that the information presented suggests that EnergyAustralia's estimates are higher than the efficient level. The AER examined the data provided in SKM's report and the method by which it developed its own cost estimates, and considers these to be an appropriate benchmark for the purposes of clause 6.5.7(e)(4) of the NER. Although EnergyAustralia's estimates are systematically higher than SKM's, the AER acknowledges the degree of uncertainty in developing such estimates and for this reason considers that efficient cost estimates reflect the midpoint between the two sources. On this basis the AER is not satisfied that the expenditure associated with EnergyAustralia's substation cost estimates reflect efficient costs that a prudent operator in the circumstances of EnergyAustralia would require, and considers that the estimates provided by SKM represent efficient costs.

7.8.3 Efficiency in scope, timing and costs

7.8.3.1 DNSP proposals

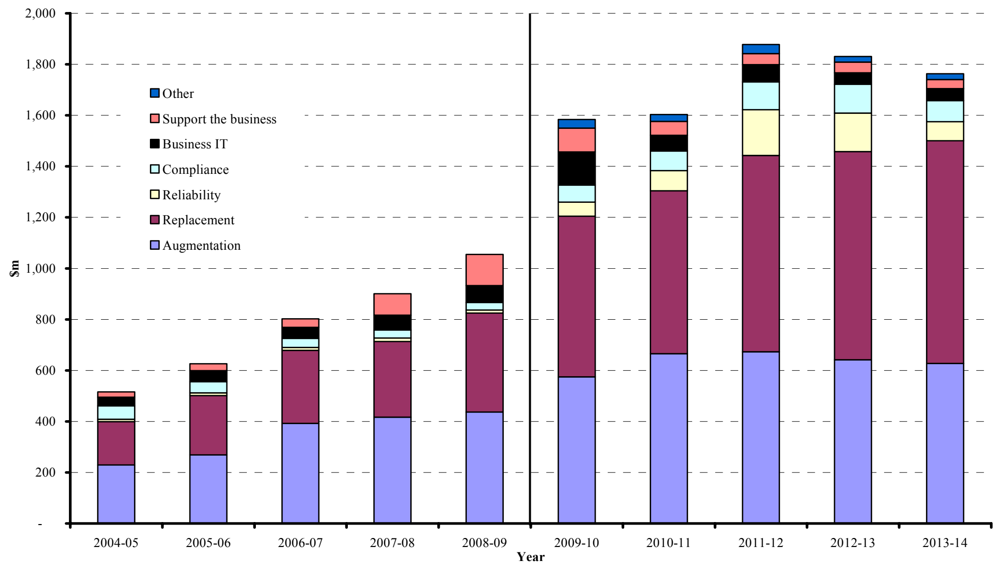
The key categories of expenditure proposed by each NSW DNSP are compared to those in the current regulatory control period in figures 7.1, 7.2 and 7.3. The major elements of the proposals are discussed below.

Figure 7.3.: Country Energy's actual and proposed capex by category ($m, 2008–09)



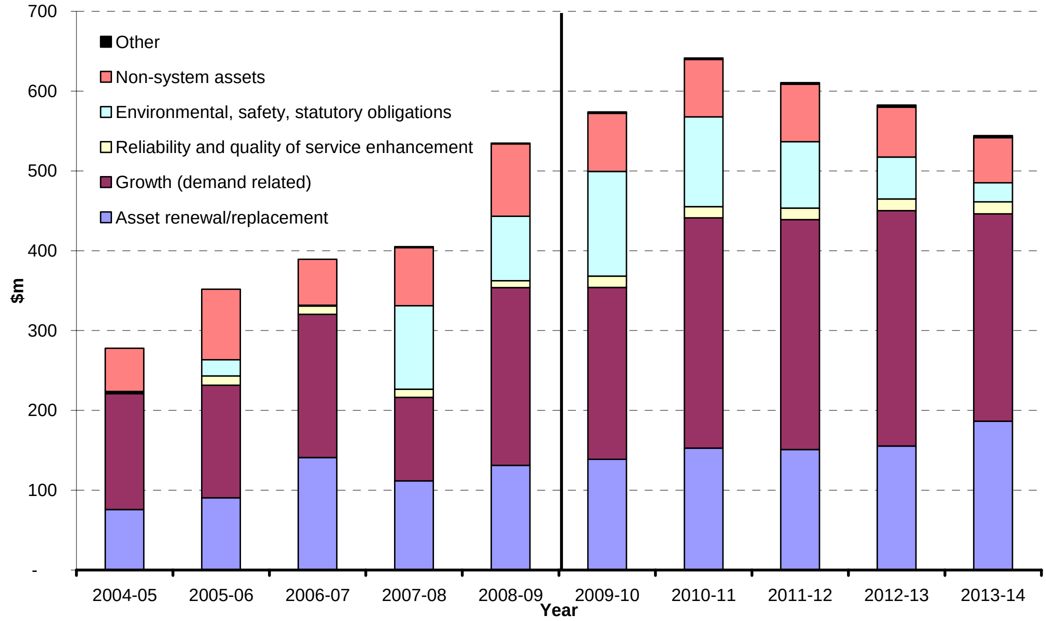
Source: Country Energy, *Regulatory proposal*, RIN template 2.2.1. Data for 2004–2009 converted to $2008–09.

Figure 7.4: EnergyAustralia's capex proposal by driver ($m, 2008–09)



Source: EnergyAustralia, *Regulatory proposal*, RIN template 2.2.1. Data for 2004–2009 converted to $2008–09.

Figure 7.5: Integral Energy's actual and proposed capex by category ($m, 2008–09)



Source: Integral Energy, *Regulatory proposal*, RIN template 2.2.1. Data for 2004–2009 converted to $2008–09.

Peak demand growth and augmentation

Country Energy has proposed growth related capex of $1417 million ($2008–09) which is around 90 per cent above that spent in the current regulatory control period. Country Energy submits that a key driver of this expenditure is a forecast annual growth rate of summer and winter peak demand of 3.0 per cent and 1.8 per cent respectively during the next regulatory control period, with a shift from a winter to a summer system peak expected during 2012–13.[432] Country Energy submits that its growth related capex is generally targeted at reinforcing the network in corridors of strong economic growth, high-density industrial areas and where step load connections are expected to occur.[433]

EnergyAustralia has proposed growth/augmentation capex of $3181 million ($2008–09) representing an 80 per cent increase from the current regulatory control period. Around half of this expenditure is contained in its area plans, a further 22 per cent is in its 11kV network development plan, 16 per cent in its customer connection plan and the remainder spread over its low voltage capacity plan and in property purchases.

Integral Energy proposed $1,346 million ($2008–09) of augmentation capex, which represents an increase of approximately 70 per cent from the current regulatory control period. Integral Energy considered this expenditure is required to serve forecast peak demand growth of 3.6 per cent annually, as well as increased customer numbers and energy consumption.

Replacement

Country Energy's forecast renewal and replacement expenditure is $806 million ($2008–09) and represents an increase of around 76 per cent from expenditure in the current period, and around 20 per cent of the forecast capex program. Programs and initiatives planned for the next regulatory control period will focus on distribution lines and cables, sub–transmission lines and cables, substations and transformers and customer metering and load control.

EnergyAustralia's replacement expenditure is a major part of its proposed allowance, representing $3729 million ($2008–09) or 43 per cent of the total forecast capex program. Expenditure proposed in this category is 168 per cent (in real terms) above that spent in the current regulatory control period. EnergyAustralia is proposing a targeted replacement program of 11kV switchgear as well as oil and gas-filled transmission and sub–transmission cables which is anticipated to take 15 to 20 years.[434]

Integral Energy has proposed asset renewal and replacement expenditure of $784 million ($2008–09) representing around 27 per cent of the total forecast capex program. Replacement capex is forecast to increase approximately 42 per cent (in real terms) on the current regulatory control period.

DRP licence conditions.

A major factor affecting the expenditures for the NSW DNSPs is the NSW DRP licence conditions which were introduced in 2005. The conditions were revised in 2007 mainly to change the compliance date for some requirements from 2009 to 2014.

The key cost implications of these licence conditions are in their planning requirements, including providing an N-2 security standard for key network elements in CBD areas and N-1 for loads greater than 10 MVA in other areas of the network.

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[432] Country Energy, *Regulatory proposal*, p. 98.

[433] The AER's assessment of Country Energy's demand forecasts is set out at chapter 5 of this draft decision.

[434] EnergyAustralia, *Regulatory proposal*, p. 36.

Other requirements relating to average and individual feeder reliability requirements are another significant cost driver in Country Energy's case. These are minimum reliability standards (SAIDI and SAIFI) across the main feeder categories (CBD, urban, short rural and long rural).[435] The average feeder standards in terms of SAIDI become progressively more onerous for each business through to 2010–11 where they reach the same standard for feeder type across the three NSW DNSPs, except for Country Energy's urban feeder category. For SAIFI and the individual feeder requirements the standards differ across the businesses.

As these standards now reflect an existing set of obligations on each DNSP, they have not been specifically costed by the businesses and the associated expenditure is spread across several expenditure categories. The impact of the requirements is, however, most prevalent in EnergyAustralia's augmentation capex, Country Energy's reliability capex and Integral Energy's compliance and reliability expenditures.

Non–system capex

Country Energy's expenditure on non–system assets is forecast to increase by 38 per cent from the current period to $684 million, and is comprised of:

- $263 million on IT
- $237 million on heavy plant and light vehicles
- $107 million on non–system land and buildings
- $77 million on furniture, fittings, plant and equipment and other non–system capex.

EnergyAustralia has proposed non–system capex of $620 million ($2008–09) for the next regulatory control period, compared with $534 million ($2008–09) in the current regulatory control period, an increase of 16 per cent. The proposal is comprised of:

- $251 million on land and buildings
- $240 million on IT systems
- $101 million on motor vehicles
- $28 million on furniture, fittings, plant and equipment.

Integral Energy proposed non–system capex of $336 million ($2008–09) in the next regulatory control period which is 8 per cent less than that spent in the current period. This expenditure is comprised of:

- $107 million on IT

[435] Note that it is actually correct to refer to these as maximum standards as they are expressed in terms of interruptions and minutes off supply, however in this paper they are referred to as minimum standards for the convenience of discussion. SAIDI: system average interruption duration index; SAIFI: system average interruption frequency index.

- $118 million on motor vehicles
- $78 million on land and buildings
- $34 million on furniture, fittings, plant and equipment.

7.8.3.2 Consultant review

In assessing the general prudence and efficiency of expenditures, Wilson Cook reviewed the following types of information:

- business cases for specific major projects and programs, as well as strategic documents including area plans (in terms of the identification of investment need, consideration of options, costing and timing)
- comparison of forecast expenditures with levels in the current period
- existing network performance (i.e. fault rates and modes) and expected changes to this in light of the capex proposed
- the relevant demand and customer characteristics as explained by each business
- a top down assessment of non–system capex through comparisons on a 'cost-per-customer' and 'cost-per-size' basis, against the other ACT and NSW DNSPs forecasts and the regulatory allowances of Ergon Energy and Energex from the 2005 Queensland network determination.

In almost all cases Wilson Cook considered the approaches adopted by the businesses to be reasonable and the resulting expenditure to be efficient.

However, Wilson Cook recommended the removal of approximately $29 million of Integral Energy's replacement capex on the basis that certain unspecified works were not reasonably justified, particularly in the context of an identified trend in replacement expenditure.[436]

For Country Energy, Wilson Cook recommended the following reductions:[437]

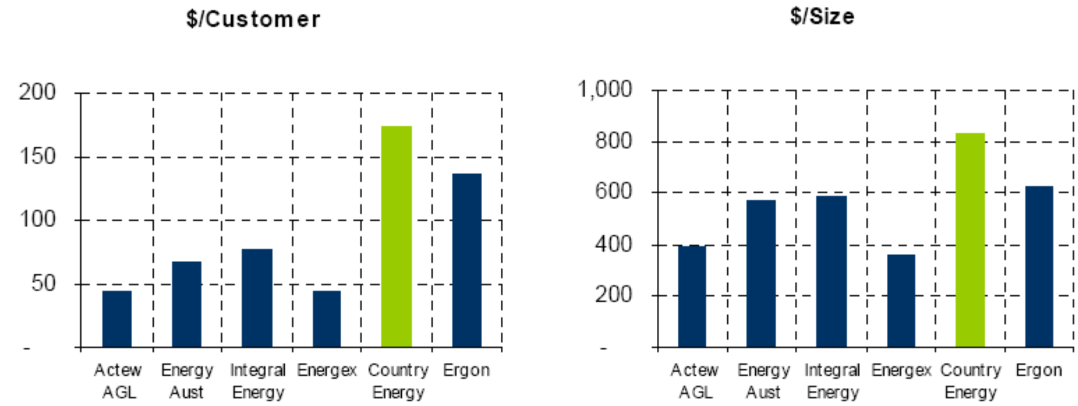
- $66 million to reflect that its IT expenditure was not justified at a project level and appeared overstated by comparison to other DNSPs
- $12 million due to some items (work on relay settings and tap positions) being incorrectly recognised as capex
- $21 million reduction to non–system land and building expenditures to correct for apparent double counting

[436] Wilson Cook, volume 3, pp. 21–23.
[437] Wilson Cook, volume 4, p. 33.

- $25 million to reflect the removal of real cost escalation to non–system capex, as Country Energy did not justify the application of the proposed escalator and Wilson Cook considered there to be no basis for a smoothed escalation.

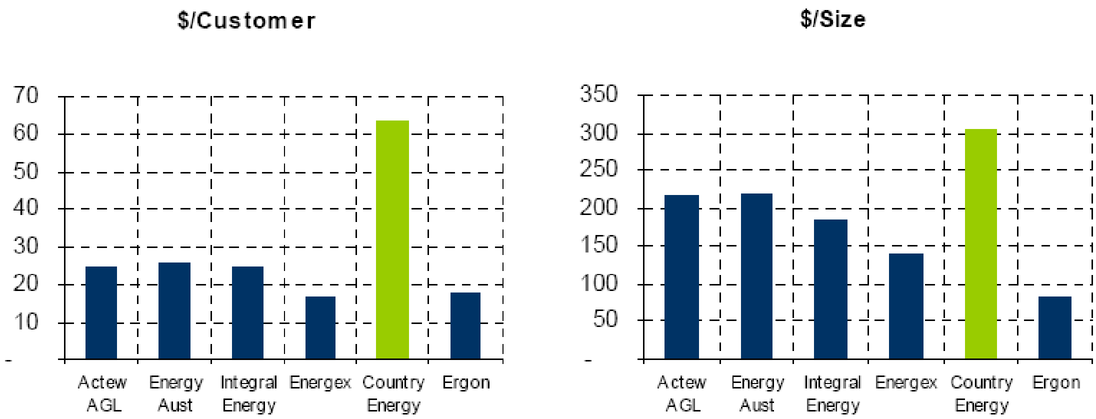
Wilson Cook's conclusions for Country Energy's non–system capex were substantiated by benchmarking analysis. These comparisons are reproduced in figure 7.6 for non–system capex in total and figure 7.7 for non–system IT capex.

Figure 7.6: Wilson Cook comparison of non–system capex



Source: Wilson Cook, volume 4, p. 30.

Figure 7.7: Wilson Cook comparison of non–system IT capex



Source: Wilson Cook, volume 4, p. 31.

Wilson Cook also observed that the NSW DNSPs were targeting levels of reliability based on differing probabilities of compliance with schedule 2 of the NSW DRP licence conditions. For example, in the case of EnergyAustralia it did not express an opinion:[438]

> … on the appropriateness of setting a target in this way since it appears to be a matter of interpretation of the licence conditions. However, we note the matter for consideration by the AER as potentially it gives rise to different levels of expenditure by the DNSPs in circumstances that otherwise would be the same.

[438] Wilson Cook, volume 2, p. 39.

7.8.3.3 AER considerations

Peak demand growth and augmentation expenditure

The AER considered the information provided to it and Wilson Cook in the form of various project and program documentation for augmentation/growth capex proposed by Country Energy and EnergyAustralia. The AER also concluded that the demand forecasts presented by these two businesses were reasonable[439] and assessed the impact of demand forecasts on the timing of specific projects. On the basis of these factors, and on the advice of Wilson Cook, the AER is satisfied that the augmentation and growth related expenditures proposed by EnergyAustralia and Country Energy reflect efficient costs that a prudent operator would require, and are also based on reasonable expectations of demand forecasts.

The AER's review of Integral Energy's augmentation capex was affected by its request for updated demand forecasts following MMA's concerns.[440] Upon incorporating the adjustments suggested by MMA, Integral Energy noted that its revised forecasts had no impact on its forecast capex. To test this finding, the AER conducted investigations into the combined impact of adjustments to specific locational loads for revised zone substations. In this assessment the AER found no material impact on Integral Energy's proposed capex and is therefore satisfied that the proposed augmentation capex reasonably reflects the efficient costs a prudent operator would require and is based on a realistic expectation of demand forecasts over the regulatory control period, consistent with the capex criteria.

As discussed in appendices K, L and M to this chapter, the AER has replicated the high-level analysis undertaken by the EMRF and considered its conclusions that the DNSPs capex proposals were significantly overstated based on a comparison of peak demand and augmentation capex. Such a comparison is limited as network peak demand is an imperfect indicator of location specific demand (which drives investment). The AER either found that a loose correlation did exist in each case, or where it did not appear so, this was explained by the impact of other factors, including the NSW DRP licence conditions.

The AER also notes that, in response to stakeholder comments, the NSW DNSPs give appropriate consideration to non–network alternatives in addressing demand growth, as evidenced by the documentation provided to the AER for specific network projects. In many projects reviewed, non–network alternatives are discounted for technical feasibility reasons, which did not seem unusual. The AER notes that Integral Energy outlines in considerable detail the many non–network initiatives it is undertaking in its proposal.[441]

Replacement expenditure

The AER reviewed the information provided in support of the replacement capex proposals for Country Energy and EnergyAustralia, and, on the basis of the advice of Wilson Cook, is satisfied that the proposed expenditures reasonably reflect the efficient costs a prudent operator would require, consistent with the capex criteria.

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439 Refer to chapter 5 of this draft decision for further discussion on Country Energy's and EnergyAustralia's demand forecasts.

440 Refer to chapter 5 of this draft decision for further discussion on Integral Energy's demand forecasts.

441 Integral Energy, *Regulatory proposal*, chapter 8.

The AER notes that EnergyAustralia's network is the oldest in the country and that it includes a notable quantity of assets installed before 1960 and a large number of assets installed between 1960 and 1985. In response to stakeholder concerns regarding the early replacement of assets, the AER highlights Wilson Cook's general comment that many of EnergyAustralia's assets: [442]

> …are now at the end or beyond their prudent engineering lives and are presenting in many cases an unacceptable safety and supply risk.

In response to stakeholders' concerns about the veracity of the NSW DNSPs' investment decisions and potential for premature asset replacement, the AER notes that the condition-based assessments which the NSW DNSPs use to inform replacement needs can result in assets being replaced before or after the end of their standard or expected lives. In conjunction with this, the NSW DNSPs also employ standardised methods to analyse the financial trade-offs between ongoing repair and maintenance of assets and their replacement, as well as the associated risks and consequences of asset failure. While these vary in sophistication between the businesses, this represents a prudent and commercial approach to asset management, and the AER is therefore satisfied that investments are efficiently timed.

The AER notes that some of EnergyAustralia's assets identified for replacement are highly utilised and that the replacement opportunities provided in the autumn and spring low-load months have been a factor underpinning the need to undertake the replacement program over a number of years.

The AER is satisfied that Integral Energy's replacement capex is generally prudent and efficient, based on its review of a sample of project documents and plans, and on Wilson Cook's advice. However, as noted by Wilson Cook, the following replacement expenditures have not been fully justified by Integral Energy and appear high in relation to historical trends:

- other substation renewal projects
- unspecified civil works
- unspecified work on sub–transmission mains.

The AER's conclusion is to make an adjustment of $29 million to Integral Energy's capex proposal which it is satisfied reasonably reflects the efficient costs a prudent operator, in the circumstances of Integral Energy, would require to achieve the capex objectives. The reasons for this adjustment are detailed in appendix M.

Average reliability performance - DRP licence conditions

The NSW DRP licence conditions mandate various planning and performance requirements for the DNSPs which have affected various elements of the capex proposals. One aspect of the licence conditions which has affected reliability expenditures are the minimum performance requirements in schedule 2. This schedule sets standards in terms of SAIDI (minutes off supply) and SAIFI (interruptions of supply) across feeder types as

[442] Wilson Cook, volume 1, p. vi.

per tables 7.4 and 7.5 below. Actual performance for 2006–07 is also listed for comparative purposes.

Table 7.4 NSW DRP licence conditions – average reliability standards- SAIDI minutes per customer, by feeder type

	2005–06	2006–07	2007–08	2008–09	2009–10	From 2010–11	Actual performance 2006–07
EnergyAustralia							
CBD	60	57	54	51	48	45	13
Urban	90	88	86	84	82	80	78
Short-rural	400	380	360	340	320	300	290
Long rural	900	860	820	780	740	700	1093
Integral Energy							
Urban	90	88	86	84	82	80	66
Short-rural	300	300	300	300	300	300	175
Long rural	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Country Energy							
Urban	140	137	134	131	128	125	114
Short-rural	340	332	324	316	308	300	239
Long rural	750	740	730	720	710	700	497

Source: NSW DRP licence conditions; DNSP annual reports.

Table7.5 DRP licence conditions – average reliability standards- SAIFI interruptions per customer, by feeder type

	2005–06	2006–07	2007–08	2008–09	2009–10	From 2010–11	Actual performance 2006–07
EnergyAustralia							
CBD	0.35	0.34	0.33	0.32	0.31	0.30	0.17
Urban	1.30	1.28	1.26	1.24	1.22	1.20	0.96
Short-rural	4.40	4.20	3.90	3.70	3.40	3.20	2.76
Long rural	8.50	8.00	7.50	7.00	6.50	6.00	5.64
Integral Energy							
Urban	1.30	1.28	1.26	1.24	1.22	1.20	0.90
Short-rural	2.80	2.80	2.80	2.80	2.80	2.80	2.00
Long rural	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Country Energy							
Urban	2.00	1.96	1.92	1.88	1.84	1.80	1.36
Short-rural	3.30	3.24	3.18	3.12	3.06	3.00	2.47
Long rural	5.00	4.90	4.80	4.70	4.60	4.50	3.82

Source: NSW DRP licence conditions; DNSP annual reports.

The AER recognises that, conceptually, the DNSPs will be required to target levels of performance that are better (or lower) than required by its licence conditions. That is, a strict interpretation of the licence conditions would require compliance 100 per cent of the time which, depending on the circumstances of the DNSP, may not be feasible to achieve. There may be some chance, however small, that actual performance on average will not meet the performance standard set in the licence conditions. While tables 7.4 and 7.5 above indicate that the DNSPs were largely compliant with targets for all categories and measures in 2006–07, this masks annual variations in actual performance which are illustrated in appendices K, L and M.

In this context, EnergyAustralia and Country Energy aim to achieve the performance targets in schedule 2 in terms of a probability of compliance. The resulting expenditures associated with this target relate to performance ‘gaps’ identified after taking into expected performance improvements due to investments for other purposes, mainly augmentation and replacement needs. As highlighted by Wilson Cook, there are implications of setting different probabilities of compliance in terms of the resulting investment required.

The AER notes that compliance with schedule 2 of the NSW DRP is a key driver of Country Energy’s proposed reliability expenditure and it has chosen to target an 80 per cent probability of compliance with the standard for each feeder type in any year.

EnergyAustralia notes that its scope of works will result in a 95 per cent probability of compliance with each standard for each feeder type in any year. This target is proposed to be achieved with incremental expenditures (i.e. after taking into account the reliability impact of its other capex programs) of $20 million, relating to the performance of one of its long rural feeders, as well as a further $9.6 million through its distribution monitoring and control program.[443]

Integral Energy claims it is targeting 100 per cent probability of compliance with the standard for each feeder type given that the current performance of the majority of its feeders is above the minimum average requirement, such that the impact of its poorer performing feeders is not sufficient to reduce average performance below the minimum requirement.[444] Integral Energy’s proposed expenditure to maintain individual and average feeder performance in accordance with the licence conditions is $73 million.[445]

Wilson Cook did not offer its opinion on the prudence of setting different expected compliance targets, but nevertheless concluded that the expenditures associated with these targets were reasonable.[446] In assessing these expenditures the AER must be satisfied that they reasonably reflect the efficient costs to achieve the capex objectives, inclduing compliance with the DRP licence conditions in accordance with clause 6.5.7(a)(2). The AER notes that the different probabilities of compliance targeted by the DNSPs are likely to reflect:

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443 EnergyAustralia, *Regulatory proposal*, attachment 4.9, pp. 18-20.

444 Integral Energy, email to AER, 1 October 2008

445 Integral Energy, *Regulatory proposal*, p. 116. Note that this also includes expenditure with respect to schedule 3 of the licence conditions in relation to individual feeder performance.

446 Wilson Cook, volume 3, pp. 25–26.

- the different electrical characteristics and operational environments of each network, which may not be fully reflected in the licence requirements (e.g. EnergyAustralia's underground feeders versus Country Energy's weather exposed feeders)

- the extent to which the current performance of each business is different, resulting in different performance gaps for feeder categories where requirements are uniform across the businesses (e.g. SAIDI on short and long rural feeders)

- the different rate at which the required standards progressively become more onerous for each business.

To explore these issues, the AER sought further information from each of the NSW DNSPs on their specific targeted levels of compliance with respect to the associated costs and circumstances, including whether they had considered alternative targets.

Country Energy referred to analysis in its Network Asset Management Plan which identified that further improvements in performance (above its 80 per cent probability of compliance target) did not appear to be justified when viewed in the context of the additional cost and resourcing implications, which gave rise to deliverability concerns. In particular, Country Energy noted that achieving 95 per cent probability of compliance would involve addressing fundamental rural network design standards, including replacement of bare conductors, undergrounding and the construction of additional zone substations. It estimated that the cost of this work would be an additional $219 million per year compared to the work program to achieve 80 per cent compliance.[447]

EnergyAustralia noted that it considered a 90 per cent probability of compliance unacceptably low, and that its chosen 95 per cent target resulted in a relatively modest amount of additional expenditure.[448]

As noted above, Integral Energy's circumstances allow it to target full compliance with the performance requirements.

For the reasons discussed above, the AER is satisfied that Country Energy, EnergyAustralia and Integral Energy have targeted appropriate levels of compliance given the relative costs and benefits of the alternatives they considered. The AER considers targeting the appropriate level of compliance is crucial in determining where the associated forecast capex reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives consistent with the capex criteria.

EnergyAustralia- black spot reliability program

EnergyAustralia's reliability expenditure includes a 'black spot' reliability program which is designed to improve performance for individual customers on the worst served segments of the network. By doing so EnergyAustralia considers it 'has filled the individual customer gap in the NSW DRP licence conditions'.[449] Schedules 2 and 3 of the licence conditions address average feeder category and individual feeder level

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447 Country Energy, email to AER, 2 October 2008.
448 EnergyAustralia, *Responses to AER question about cost escalation & reliability targets of 26 September 2008*, 3 October 2008.
449 EnergyAustralia, *Regulatory proposal*, p. 65.

performance respectively. EnergyAustralia notes that, on individual feeders, particularly those with significant segmentation through the use of reclosers and fuses, customers further away from the zone substation can experience a level of performance significantly below that for the feeder average. EnergyAustralia argues that the 'black spot' reliability program will be used to 'initiate appropriate reliability improvements'.[450]

The AER does not consider that the expenditure associated with the 'black spot' reliability program, as described by EnergyAustralia, is consistent with the efficient costs required to achieve the capex objectives as it is not required to:

- comply with an applicable regulatory obligation or requirement
- meet or manage the expected demand for standard control services
- maintain the quality, reliability and security of supply of standard control services
- maintain the reliability, safety and security of distribution system through the supply of these services.

The AER's detailed reasons are contained in appendix L. Overall, the AER is not satisfied that the objective of the 'black spot' reliability program is consistent with the capex objectives, in particular that it is not necessary to maintain the quality, reliability and security of supply of standard control services or the reliability, safety and security of the distribution system. The AER is similarly not satisfied that the associated costs reasonably reflect the capex criteria, being the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives.

The AER notes that this project represents a small proportion of EnergyAustralia's capex proposal and that, under the ex ante incentive framework, EnergyAustralia may proceed with the program if it considers it appropriate to do so.

EnergyAustralia – contingent project

EnergyAustralia lodged a contingent project application under chapter 6A with the AER on 9 May 2008 to replace two of its feeder cables (908 and 909). In assessing this proposal the AER determined that a total forecast capex of \$134 million (\$2003–04) for this contingent project was appropriate.[451] The approved expenditure on this project spans the current and next regulatory control periods, and is equal to \$152m (\$2008–09).

In determining the allowance for the remaining forecast capex to be incurred during the next regulatory control period for this contingent project, the AER has applied clause 6A.6.7 as required by the relevant transitional provision for EnergyAustralia (clause 11.6.19(g) of the NER). According to clause 6A.6.7(h), the capex that EnergyAustralia proposed in the next regulatory control period for the replacement of these cables should be equal to the difference between the total capex determined by the AER for the contingent project and the total capex incurred by EnergyAustralia in the current regulatory control period.

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[450] EnergyAustralia, *Regulatory proposal*, p. 65.
[451] AER, *Contingent project application: EnergyAustralia Replacement of feeder cables 908 and 909: Decision*, July 2008.

In preparing its capex proposal for the next regulatory control period EnergyAustralia noted that it would spend $114m ($2008–09) on feeders 245 and 246 which replace feeders 908 and 909.[452] This is out of a total expected capex of $160 million ($2008–09) which is greater than the allowed in the AER's contingent project decision.

In applying clause 6A.6.7 and the AER's contingent project decision, the AER does not agree with EnergyAustralia's proposed $160 million. Instead the AER considers the capex allowance for the replacement of feeders 908 and 909 for the next regulatory control period is $107 million ($2008–09). This is the difference between the total capex determined by the AER for the contingent project, $152 million ($2008–09), and the total capex incurred in the current period by EnergyAustralia, $46 million ($2008–09).

Non–system capex

The AER's conclusions with respect to the DNSPs' non–system capex proposals are summarised here and outlined in full detail in appendices K, L and M.

The AER considers that Wilson Cook's benchmarking of non–system capex has been effective in assessing the expenditures proposed as this type of expenditure displays a relatively consistent relationship with a DNSP's number of customers and network size. In this regard, its review of project documentation in a bottom up sense has been effectively used to validate its findings from a top down perspective and, when taken together, provide a strong basis for its recommendations.

In this context the AER considers that the non–system capex proposed by Integral Energy and EnergyAustralia reflects the efficient costs that a prudent operator in the circumstances of both of these DNSPs would require to achieve the capex objectives.

The AER agrees with Wilson Cook's findings on Country Energy's non–system capex regarding the following:

- the application of a real weighted average cost escalator to a diverse range of non–system expenditure program has not been justified and does not result in expenditure that reflects efficient costs

- Country Energy's proposed IT expenditure appears high by comparison to its peers and is not sufficiently justified in financial terms. The AER accepts the advice of Wilson Cook that this category should be reduced by 25 per cent to bring it to a level which is comparable with other DNSPs and therefore considered efficient

- Country Energy appears to have double counted costs when forecasting building and accommodation requirements due to workforce expansion. The AER has accepted Wilson Cook's recommendation that this expenditure category should be reduced by 50 per cent to correct for this.

The AER concludes that it is not satisfied that Country Energy's forecast non–system capex reasonably reflects the efficient costs that a prudent operator in Country Energy's circumstances would require to achieve the capex objectives in accordance with the capex criteria, in particular clause 6.5.7(c)(2) of the transitional chapter 6 rules.

452 EnergyAustralia, *Regulatory proposal*, p. 100.

7.8.4 Cost accumulation

7.8.4.1 DNSP proposals

The NSW DNSPs engaged CEG to provide an assessment of forecast movements in the cost of input components in their capex proposals. CEG previously advised ElectraNet as part of its recent transmission determination review, on which the AER expressed its opinion about the various methods and data sources used. The AER considered the recognition of real cost escalators in its decisions for SP AusNet.[453] That decision recognised the recent commodities price boom and skilled labour shortages in Australia as a key cost driver, resulting in a need to compensate regulated businesses for cost increases above CPI.

EnergyAustralia and Country Energy applied the CEG recommended escalators in full, while Integral Energy adopted all with the exception of the producer's margin and indirect labour escalators. Further details are provided in appendices K, L and M.

7.8.4.2 Consultant review

The terms of reference required Wilson Cook to develop appropriate escalators for the cost of material. This would enable comparison with the costs that the NSW DNSPs applied when preparing their expenditure forecasts. Wilson Cook did not consider this appropriate as DNSPs retained expert advice to project future material (and labour) price movements. Wilson Cook considered escalation rates assumed for the main material or asset categories as modest and did not reflect a continuation of the rapid escalation of costs evident in the electricity supply industry experienced in Australasia in recent years.[454]

Wilson Cook was not able to express a view on the reasonableness of the assumptions made regarding future cost movements (in particular the escalation factors determined by CEG). Nor was Wilson Cook able to verify that the method had been applied in the stated manner.

7.8.4.3 AER considerations

The AER's detailed considerations and decision on each escalator and associated forecasting method arising out of CEG's recommendations are contained in appendix N.

In response to stakeholder comments on this issue, the AER engaged Econtech to provide independent forecasts of wages growth in NSW. The AER notes that the labour component of expenditures is large particularly for operating and maintenance expenditures. In all other cases the AER has assessed the validity of the proposed escalators with respect to data from published sources, and has closely examined how each escalator contributed to the proposed expenditures.

The AER does not accept Country Energy's proposed escalator for timber poles, which is derived by weighting wages, producer's margin and a proportion escalated by CPI only. Country Energy has not provided sufficient evidence to suggest that timber poles are

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[453] AER, *Draft Decision – SP AusNet transmission determination 2008–09 to 2013-14*, 31 August 2007, pp. 87–91, 316–331.

[454] Wilson Cook, volume 1, pp. 10–11.

expected to experience real cost increases during the next regulatory control period. As noted above, the AER also did not accept Country Energy's proposed cost escalator for non–system capex.

The AER identified several errors in EnergyAustralia's application of real escalators which, when corrected, resulted in a material reduction to its capex program. In addition, the AER did not agree with EnergyAustralia's proposed lag between commodity price increases (and labour costs), and the costs it faces in the purchase of equipment and the delivery of its investment programs.

The AER also considered that EnergyAustralia's proposed escalator for poles was not adequately explained. Moreover, it was high by comparison to those escalators proposed by Integral Energy and ActewAGL for what the AER considers to be a fairly generic asset type. For these reasons the AER did not accept EnergyAustralia's pole escalator. The AER considered EnergyAustralia's proposed escalators for components of non–system capex, namely land, buildings and general IT labour, to be reasonable.

With respect to material cost escalators proposed by Integral Energy as part of its forecast capex allowance, the AER has made adjustments to the method used to forecast copper, steel and aluminium as proposed by CEG, and used updated data with respect to forecast construction costs, crude oil and exchange rates which are used in the conversion of costs into Australian dollar terms.

7.8.5 Deliverability

7.8.5.1 DNSP proposals

As noted in section 7.5, the combined proposed capex allowances for the NSW DNSPs is $15 652 million, which is 94 per cent more than the $8065 million spent in the current regulatory control period.

Country Energy has also proposed to implement the following resourcing strategies during the next regulatory control period:[455]

- continued recruitment and establishing an adequate mix on internal and external resources to complete additional works
- continued intake of new apprentices and graduates from a wide range of disciplines
- targeting of qualified tradespeople and technical support from other related industries, including from interstate and overseas
- retention and attraction of employees through competitive wages
- contracting of external specialised services through publicly tendered contracts and development of strategic relationships with external service providers to match resource requirements to program resource demands

[455] Country Energy *Regulatory proposal*, p. 29

- ensuring effective internal contract management resources to administer increased project work undertaken by external providers

- increased motor vehicle and heavy fleet purchases

- continued improvement of corporate governance framework for capital investments.

The deliverability strategies proposed by EnergyAustralia are to:[456]

- increase the capability of its staff through the use of standardised designs, advanced design software, network automation and the deployment of mobile computing

- increase the work undertaken by contractors, for example, for cable laying, civil and building work

- establish alliance agreements with private sector construction companies and consultants to undertake major projects under turn-key-style arrangements.

During the current regulatory control period, Integral Energy implemented (or has commenced implementing) a range of initiatives to ensure the capital program is delivered in an efficient and sustainable manner, including:[457]

- design standardisation

- supply chain management

- alternative delivery models

- increased internal staffing.

7.8.5.2 Consultant's review

Wilson Cook reviewed the delivery strategies of each DNSP and in each case considered there were no reasons to conclude that the necessary resources could not be mobilised to implement the programs.

7.8.5.3 AER considerations

The AER shares the concerns of stakeholders that the proposed programs represent a significant increase above the amount of expenditures incurred in the current regulatory control period, and that network users may potentially face a higher risk of paying, through regulated prices, for investments that may not eventuate.

The AER notes that the NSW DNSPs have explored options to defer and appropriately time its investments in light of the risk of resource constraints. EnergyAustralia noted that it has deferred $50 million of network investment through demand management.[458] It also noted that its capex has ramped up over the current regulatory control period at a rate of between $150 and $200 million per year, and it has considered targeted increases of

[456] EnergyAustralia, *Regulatory proposal*, p. 75.
[457] Integral Energy, *Regulatory proposal*, pp 90–91.
[458] EnergyAustralia, *Regulatory proposal*, p. 96.

$200 million per year in planning its capex proposal, which forced it to consider deferrals, demand management and bearing higher risk of asset failure.[459]

The AER acknowledges the point made by the NSW DNSPs that the increase in value of the programs between the current and next regulatory control periods reflects, to a material extent, increases in the real cost of inputs. For example, EnergyAustralia attributes approximately 10 per cent of the increase in capex between the current and next regulatory control periods to real price increases.[460]

Taking a longer term perspective, the amount of capex spent by EnergyAustralia in the 2004–09 period was 124 per cent above the amount spent in the 1999–04 regulatory control period, which compares to the 120 per cent increase proposed for the next regulatory control period. Integral Energy's capex over the 2004–09 period was 118 per cent above that spent over 1999–04 (compared to a 49 per cent increase proposed for the 2009–14 period) while Country Energy's capex over the 2004–09 period was 102 per cent above that spent over 1999–04 (compares to a 81 per cent increase proposed for the 2009–14 period.

Integral Energy's forecast capex program for the next regulatory control period in annual average terms is $591 million ($2008–09) which is of a similar magnitude to the $535 million expected to be spent in 2008–09. Further, as illustrated in table 7.1 and figure 7.1 above, the NSW DNSPs' capex on an annual basis has generally been increasing steadily during the current regulatory control period.

These comparisons indicate that the NSW DNSPs are capable of delivering significant increases in capex, including expenditure in excess of the regulatory allowances. To date, access to finance has not been a constraint on the NSW DNSPs ability to undertake capital works beyond their regulatory allowance. However, instability in world financial markets and concerns about debt levels may prove to be a constraint going forward.[461]

The strategies proposed by the NSW DNSPs appear reasonable as noted by Wilson Cook. However the AER does have some concerns that the NSW DNSPs will be concurrently seeking resources and using overlapping delivery strategies, including with TransGrid and other Australian DNSPs and TNSPs. This is addressed, to some extent, by an expectation that the Australian and global economies are entering a period of reduced activity which will see a decline in demand for resources and materials.

Given the very high concurrent level of investment proposed for the NSW distribution (and transmission) electricity networks, the AER will carefully monitor the expenditures of the NSW DNSPs on an annual basis and through its annual regulatory reports will

459 EnergyAustralia, *Regulatory proposal*, p. 74.

460 EnergyAustralia, *Regulatory proposal*, Attachment 11.1, p. 4.

461 The AER notes that the NSW Government's *Mini Budget 2008–09* provides for an $857 million reduction over three years in the borrowing capacity of the NSW DNSPs and TransGrid. The AER has assessed this financing constraint against the proposed capex programs from 2009-10 to 2011-12 and is satisfied that this need not adversely impact on the deliverability of the program. The reduction in the borrowing program represents a relatively small proportion of the capex program and its impact may be offset by increased internal efficiencies in each of the businesses and or by a change in the timing of dividend payments to the to the shareholder. See http://www.treasury.nsw.gov.au/data/assets/pdf_file/0016/12706/08–09_Mini-Budget.pdf.

publish information on the actual capex spent by each of the NSW DNSPs, including any under or over spends if they occur.

7.9 AER conclusion

For the reasons summarised in this chapter and detailed in appendices K, L and M, the AER is not satisfied that the proposed forecast capex allowances of each DNSP reasonably reflect the capex criteria, under clause 6.5.7(c). In reaching this conclusion, the AER has regarded the capex factors set out in 6.5.7(e).

As the AER is not satisfied that the capex allowances proposed by the DNSPs reasonably reflect the capex criteria, under clause 6.5.7(d) the AER must not accept them in its distribution determination. Under clause 6.12.1(3)(ii), the AER is therefore required to provide an estimate of the capex for each DNSP over the next regulatory control period it is satisfied reasonably reflects the capex criteria, taking into account the capex factors.

The AER's conclusions, the adjustments it requires and the resulting estimates of the forecast capex allowance it is satisfied reasonably reflects the capex criteria during the next regulatory control period for each DNSP are summarised below.

7.9.1 Country Energy

Following its review of Country Energy's capex proposal the AER has made the following adjustments:

- $66 million (25 per cent) reduction to forecast IT expenditure
- $21 million reduction to non–system land and building expenditures to correct for apparent double counting
- $12 million reduction to reflect that certain works (work on relay settings and tap positions) should not be capitalised
- $46 million net increase to reflect the application of modified input cost escalators to system and non–system capex (including updated CPI data) as determined in appendix N.

Following the adjustments outlined above, and as detailed in table 7.6, the AER is satisfied an estimate of $3955 million for Country Energy's forecast capex reasonably reflects the capex criteria.

Table 7.6: AER's conclusion on Country Energy's capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy proposed capex	752.0	779.0	806.0	822.0	849.5	4008.4
Adjustment for incorrect capitalisation of tap changer setting expenditure	–2.4	–2.4	–2.4	–2.4	–2.5	–12.1
Adjustment for 25 per cent efficiency for IT expenditure	–15.9	–12.2	–12.4	–12.5	–12.6	–65.6
Adjustment for non–system land and buildings	–7.4	–4.1	–3.3	–3.0	–3.1	–20.8
Adjustments to cost escalators (including updated CPI)	16.2	16.5	12.0	5.3	4.5	45.5
AER capex allowance	742.6	776.8	799.9	809.3	826.7	3955.4

7.9.2 EnergyAustralia

The AER has made adjustments to EnergyAustralia's forecast capex to reflect the following conclusions:

- the expenditure associated with EnergyAustralia's 'black spot' reliability program does not reflect the capex objectives in clause 6.5.7(a)
- EnergyAustralia's proposed capex for the replacement of feeders 908 and 909 does not comply with clause 11.6.19(g) of the transitional chapter 6 rules
- EnergyAustralia's proposed non-civil substation capex does not reflect the capex objectives in clause 6.5.7(a) of the transitional chapter 6 rules
- the expenditure associated with EnergyAustralia's application of input cost escalators does not reflect a realistic expectation of the cost inputs required to achieve the capex objectives. Specifically, the AER has:
  - removed the effect of EnergyAustralia's assumed six month lag in input prices for key equipment costs
  - modified the input cost escalators to reflect those determined in appendix N
  - removed the real cost escalation of expenditure on wood poles
  - corrected errors in the cost escalation model.

Following the adjustments outlined above, and as detailed in table 7.7 and 7.8, the AER is satisfied an estimate of $8.4 billion for EnergyAustralia's forecast capex (for transmission and distribution) reasonably reflects the capex criteria.

Table 7.7: AER's conclusion on EnergyAustralia's distribution capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total EnergyAustralia proposed capex	1319.7	1432.8	1611.2	1483.6	1533.3	7380.6
Adjustment for correction of errors	–15.2	–20.4	–24.6	–17.1	–22.8	–100.0
Adjustments to cost escalators	3.0	–1.6	–15.2	–25.5	–44.1	–83.5
Adjustment to substation cost estimates	–4.3	–5.9	–5.0	–4.3	–3.5	–23.0
Adjustment to 'black spot' reliability project	–3.2	–3.2	–3.2	–3.3	–3.3	–16.2
AER capex allowance	1300.0	1401.8	1563.1	1433.4	1459.6	7157.9

Table 7.8: AER's conclusion on EnergyAustralia's transmission capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total EnergyAustralia proposed capex	264.2	170.5	266.6	346.7	229.9	1278.0
Adjustment for correction of errors	11.1	12.4	6.2	5.9	8.8	44.4
Adjustments to cost escalators	–3.4	–1.2	–5.9	–9.7	–6.9	–27.0
Adjustment to substation cost estimates	–1.6	–1.7	–2.0	–3.2	–2.4	–10.9
Adjustment to replacement of feeders 908 & 909	–6.4	–1.2	–	–	–	–7.6
AER capex allowance	264.0	178.9	264.9	339.7	229.3	1276.8

7.9.3 Integral Energy

The AER has made adjustments to Integral Energy's forecast capex on the basis that the expenditure for the following items does not reflect efficient expenditure required to meet the capex objectives:

- other substation renewal projects
- unspecified civil works
- unspecified work on sub–transmission mains.

The AER has also modified Integral Energy's cost escalation calculations as it is not satisfied they reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives. Specifically, the AER's amended real input cost escalators reflect:

- methods it considers appropriate to forecast steel, copper and aluminium prices
- updated source data, where appropriate.

Following the adjustments outlined above, and as detailed in table 7.9, the AER is satisfied an estimate of $2914 million for Integral Energy's forecast capex reasonably reflects the capex criteria.

Table 7.9: AER's conclusion on Integral Energy's capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Integral Energy proposal	573.9	641.5	610.4	582.5	544.3	2952.7
Adjustments arising from replacement capex	0.0	–2.1	–3.1	–4.4	–20.1	–29.8
Adjustments arising from real cost escalators[a]	–2.0	–1.4	–1.0	–2.5	–2.4	–9.3
AER capex allowance	571.9	638.0	606.3	575.5	521.9	2913.7

Note: Totals may not add due to rounding
(a) Includes impact of revised inflation and AER adjustments on 2007–08 base capex.

7.10 AER draft decision

In accordance with clause 6.12.1(3)(ii) of the transitional chapter 6 rules the AER does not accept Country Energy's forecast capex for the next regulatory control period. The AER is not satisfied that Country Energy forecast capex, taking into account the capex factors reasonably reflects the capex criteria in clause 6.5.7 of the transitional chapter 6 rules. The AER's reasons for this decision are set out in section 7.8 of the draft decision. The AER's estimate of the total capex required by Country Energy in the next regulatory control period, that reflects the capex criteria taking into account the capex factors, is set out in table 7.6 of the draft decision.

In accordance with clause 6.12.1(3)(ii) of the transitional chapter 6 rules the AER does not accept EnergyAustralia's forecast capex for the next regulatory control period. The AER is not satisfied that EnergyAustralia's forecast capex, taking into account the capex factors reasonably reflects the capex criteria in clause 6.5.7 of the transitional chapter 6 rules. The AER's reasons for this decision are set out in section 7.8 of the draft decision. The AER's estimate of the total distribution and transmission capex required by EnergyAustralia in the next regulatory control period, that reflects the capex criteria taking into account the capex factors, is set out in tables 7.7 and 7.8 respectively of the draft decision.

In accordance with clause 6.12.1(3)(ii) of the transitional chapter 6 rules the AER does not accept Integral Energy's forecast capex for the next regulatory control period. The AER is not satisfied that Integral Energy forecast capex, taking into account the capex factors reasonably reflects the capex criteria in clause 6.5.7 of the transitional chapter 6 rules. The AER's reasons for this decision are set out in section 7.8 of the draft decision. The AER's estimate of the total capex required by Integral Energy in the next regulatory control period, that reflects the capex criteria taking into account the capex factors, is set out in table 7.9 of the draft decision.

8 Forecast operating expenditure

8.1 Introduction

This chapter sets out the NSW DNSPs' opex proposals, submissions from interested parties, a summary of consultants' reviews and the AER's conclusion on the DNSPs' opex allowances for the next regulatory control period.

The opex forecasts in the DNSPs' proposals are based on their requirements for the provision of standard control services during the next regulatory control period. The AER has reviewed these opex proposals against the requirements of the transitional chapter 6 rules.

8.2 Regulatory requirements

Under clause 6.12.1(4) of the transitional chapter 6 rules, the AER must make a decision to accept or not accept the forecast opex included in a building block proposal. If the AER does not accept the proposal it must form its own estimate in accordance with the opex criteria and factors outlined in clause 6.5.6 of the transitional chapter 6 rules.

8.2.1 Opex objectives

Clause 6.5.6(a) of the transitional chapter 6 rules provides that a DNSP must include the total forecast opex for the regulatory control period in order to achieve the following opex objectives:

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) maintain the quality, reliability and security of supply of standard control services;

(4) maintain the reliability, safety and security of the distribution system through the supply of standard control services.

8.2.2 Opex criteria and factors

Clause 6.5.6(c) also provides that the AER must accept the opex forecast included in a building block proposal if it is satisfied that the total of the forecast opex for the regulatory control period reasonably reflects:

(1) the efficient costs of achieving the opex objectives; and

(2) the costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives; and

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

In making this assessment the AER must have regard to the following opex factors (clause 6.5.6(e)):

(1) the information included in or accompanying the building block proposal;

(2) submissions received in the course of consulting on the building block proposal;

(3) any analysis undertaken by or for the AER and published before the distribution determination is made in its final form;

(4) benchmark opex that would be incurred by an efficient DNSP over the regulatory control period;

(5) the actual and expected opex of the DNSP during any preceding regulatory control periods;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between opex and capex;

(8) whether the total labour costs included in the capex and opex forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period;

(9) the extent to which the forecast of required opex of the DNSP is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms; and

(10) the extent the DNSP has considered, and made provision for, efficient non–network alternatives.

Clause 6.5.6(d) of the transitional chapter 6 rules states that, if the AER is not satisfied that a DNSP's forecast opex reasonably reflects the opex criteria, then the AER must not accept the forecast opex in a building block proposal. If the AER does not accept the total forecast opex proposed by a DNSP, clause 6.12.1(4)(ii) requires the AER to include in its draft decision:

> …an estimate of the total of the DNSP's required opex for the regulatory control period that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

8.3 NSW DNSP proposals

Table 8.1 sets out the DNSPs' forecast opex proposals by cost category for the next regulatory control period.[462]

[462] EnergyAustralia's opex proposal includes both distribution and transmission opex.

Table 8.1: NSW DNSPs' forecast opex proposals ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy						
Controllable opex	400.3	408.4	420.9	435.4	451.0	2116.0
Self insurance costs	3.9	3.9	3.9	3.9	3.9	19.5
Debt raising costs	3.8	4.4	4.8	5.3	5.9	24.2
Proposed total opex	408.1	416.7	429.7	444.7	460.7	2159.8
EnergyAustralia[a]						
Controllable opex[b]	555.8	571.1	587.6	610.9	623.4	2948.8
EnergyAustralia's controllable opex forecast (less self insurance costs)[c]	550.0	565.2	581.8	605.1	617.6	2919.7
Self insurance costs	5.8	5.8	5.8	5.8	5.8	29.1
Debt raising costs	7.5	8.7	9.9	11.2	12.5	49.7
Equity raising costs	–	–	16.2	16.2	16.2	48.5
Proposed total opex	563.3	579.9	613.7	638.3	652.1	3047.0
Integral Energy						
Controllable opex	281.3	279.6	283.6	290.2	296.6	1431.3
Self insurance costs	3.2	3.2	3.3	3.3	3.3	16.3
Debt raising costs	3.5	3.8	4.2	4..6	5.0	21.1
Equity raising costs	–	–	–	4.1	4.0	8.2
Proposed total opex	287.9	286.7	291.1	302.2	308.9	1476.8

Sources: Country Energy, *Regulatory proposal*, p. 61–63 and RIN proforma;
EnergyAustralia, *Regulatory proposal*, RIN proforma;
Integral Energy, *Regulatory proposal*, p. 149.

Note: Totals may not add up due to rounding.

(a) EnergyAustralia updated its original opex forecast to reflect further analysis in regard to the relationship between capex and maintenance expenditure.

(b) Includes self insurance costs.

(c) To ensure comparability with the other DNSPs the AER has restated EnergyAustralia's forecast controllable opex with these self insurance costs removed.

The DNSPs submitted opex proposals for the next regulatory control period totalling $6.7 billion ($2008–09), which represents an increase of $1.9 billion or 40 per cent over that spent in the current regulatory control period. An overview of the DNSPs' opex forecasts is provided below. Further details of the opex proposals are provided at appendices O, P and Q.

8.3.1 Country Energy

Table 8.2 sets out Country Energy's forecast opex by cost category and year for the next regulatory control period.

Table 8.2: Country Energy's forecast opex by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Network operating costs	17.7	17.7	17.9	18.2	18.5	89.9
Network maintenance costs						
Inspection	38.3	39.2	40.4	41.8	43.2	202.9
Pole replacement	2.2	2.3	2.3	2.4	2.5	11.8
Maintenance and repair	67.7	69.2	71.4	73.9	76.5	358.7
Vegetation management	105.1	108.0	112.3	117.3	122.7	565.3
Emergency response	48.0	48.2	48.8	49.7	50.1	245.3
Other network maintenance costs	83.8	85.6	88.3	91.4	94.6	443.8
Other costs						
Meter reading	19.2	19.6	20.3	21.0	21.7	101.8
Customer service	13.4	13.7	14.2	14.7	15.2	71.2
Advertising, marketing and promotions	4.8	4.9	5.1	5.3	5.4	25.5
Other operating costs	0.0	0.0	0.0	0.0	0.0	0.0
Total controllable opex	400.3	408.4	420.9	435.4	451.0	2116.0
Self insurance costs	3.9	3.9	3.9	3.9	3.9	19.5
Debt raising costs	3.8	4.4	4.8	5.3	5.9	24.2
Total opex	408.1	416.7	429.7	444.7	460.7	2159.8

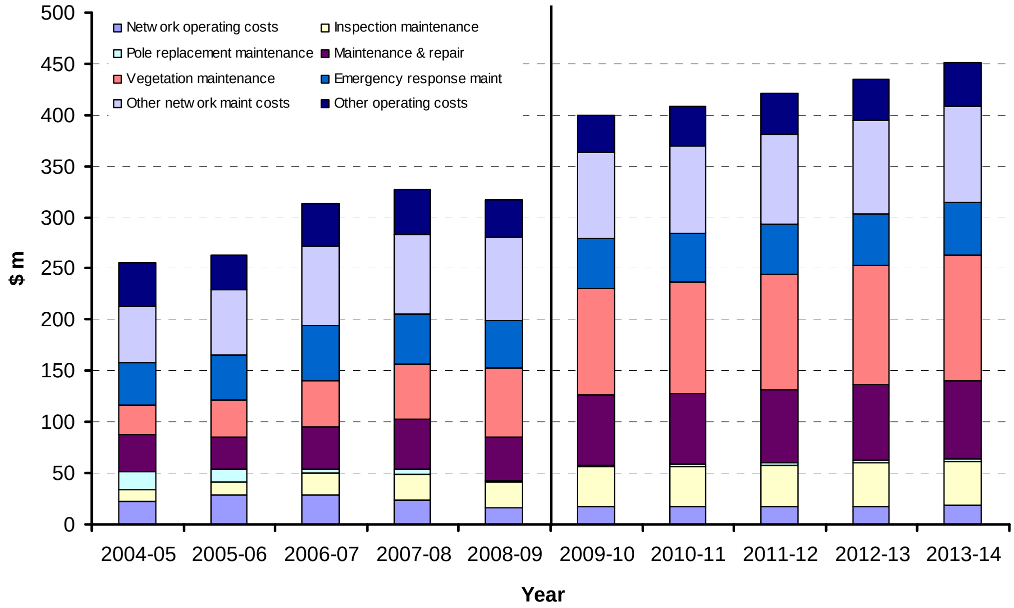
Source: Country Energy, *Regulatory proposal*, p. 63.
Note: Totals may not add up due to rounding.

Country Energy's total forecast opex for the next regulatory control period is $2160 million, which is $626 million (42 per cent) more than its expected opex in the current regulatory control period.

Controllable opex

Figure 8.1 shows Country Energy's actual and expected opex in the current regulatory control period, and its forecast opex for the next regulatory control period.

Figure 8.1: Country Energy's actual and forecast opex 2004–2014 ($m, 2008–09)



Source: Country Energy, RIN proforma 2.2.2.

The total controllable opex proposed for the next regulatory control period is $2116 million compared with an estimated $1491 million in the current regulatory control period, an increase of 42 per cent. A high proportion (87 per cent) of Country Energy's controllable opex is attributed to network maintenance. Country Energy indicated that the increase in controllable opex over the next regulatory control period reflected:[463]

- new, deferred and backlog asset inspection and maintenance works to mitigate risk and improve network performance
- cost increases above inflation for labour and input materials
- increased workload due to additional assets.

Self insurance and debt raising costs

Country Energy proposed to include $20 million for self insurance costs[464] and $24 million for debt raising costs for the next regulatory control period.[465]

8.3.2 EnergyAustralia

Unlike Country Energy and Integral Energy, EnergyAustralia incorporated costs associated with self insurance as part of its forecast controllable opex. To ensure comparability with the other DNSPs, the AER has restated EnergyAustralia's forecast controllable opex with these self insurance costs removed. This restatement to

463 Country Energy, *Regulatory proposal*, pp. 63–64.
464 Country Energy subsequently indicated that costs associated with general public liability claims are already included and recovered through its regulatory submission and therefore the associated estimate in the self insurance forecast (approximately $46,000 over the regulatory period) should be omitted.
465 Country Energy, *Regulatory proposal*, p. 61.

EnergyAustralia's controllable forecast opex, as well as EnergyAustralia's forecast opex by cost category and year for the next regulatory control period, are set out in table 8.3.

Table 8.3: EnergyAustralia total forecast opex by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Network operating	182.7	189.1	190.8	196.1	198.6	957.3
Network maintenance	219.7	226.0	236.7	247.7	260.7	1190.9
Other expenditure	155.3	159.2	165.1	172.2	172.4	824.2
Total controllable opex[a]	557.8	574.3	592.6	616.0	631.7	2972.4
Total controllable opex less self insurance costs[b]	552.0	568.5	586.8	610.2	625.9	2943.3
Self insurance costs	5.8	5.8	5.8	5.8	5.8	29.1
Debt raising costs	7.5	8.7	9.9	11.2	12.5	49.7
Equity raising costs	–	–	16.2	16.2	16.2	48.5
Proposed total opex	565.2	583.0	618.6	643.4	660.6	3070.6

Source: EnergyAustralia, RIN.
Note: Totals may not add up due to rounding.
(a) Includes self insurance costs.
(b) To ensure comparability with the other DNSPs the AER has restated EnergyAustralia's forecast controllable opex with these self insurance costs removed.

In response to a number of issues raised by Wilson Cook, EnergyAustralia undertook further analysis in relation to the relationship between capex and maintenance expenditure. As a result of this analysis, EnergyAustralia's forecast network maintenance expenditure was reduced by $19 million.[466] EnergyAustralia also advised that it identified errors in its asset age profile information which further reduced its opex forecast by $4 million. The adjusted maintenance expenditure forecasts and the consequent updated opex forecasts for the next regulatory control period are provided in table 8.4.

[466] EnergyAustralia, response to Wilson Cook, 15 August 2008.

Table 8.4: EnergyAustralia's updated forecast opex by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Network operating	182.7	189.1	190.8	196.1	198.6	957.3
Network maintenance	217.7	222.7	231.8	242.6	252.4	1167.3
Other expenditure	155.3	159.2	165.1	172.2	172.4	824.2
Total controllable opex[a]	555.8	571.1	587.6	610.9	623.4	2948.8
Total controllable opex less self insurance costs[b]	550.0	565.2	581.8	605.1	617.6	2919.7
Self insurance costs	5.8	5.8	5.8	5.8	5.8	29.1
Debt raising costs	7.5	8.7	9.9	11.2	12.5	49.7
Equity raising costs	–	–	16.2	16.2	16.2	48.5
Proposed total opex	563.3	579.9	613.7	638.3	652.1	3047.0

Source: EnergyAustralia RIN; and Wilson Cook, volume 2, p. 56.
Note: Totals may not add up due to rounding.
(a) Includes self insurance costs.
(b) To ensure comparability with the other DNSPs, the AER has restated EnergyAustralia's forecast controllable opex with these self insurance costs removed.

EnergyAustralia's total forecast opex for the next regulatory control period is $3047 million, which is $902 million (30 per cent) greater than its expected opex in the current regulatory period.

Controllable opex

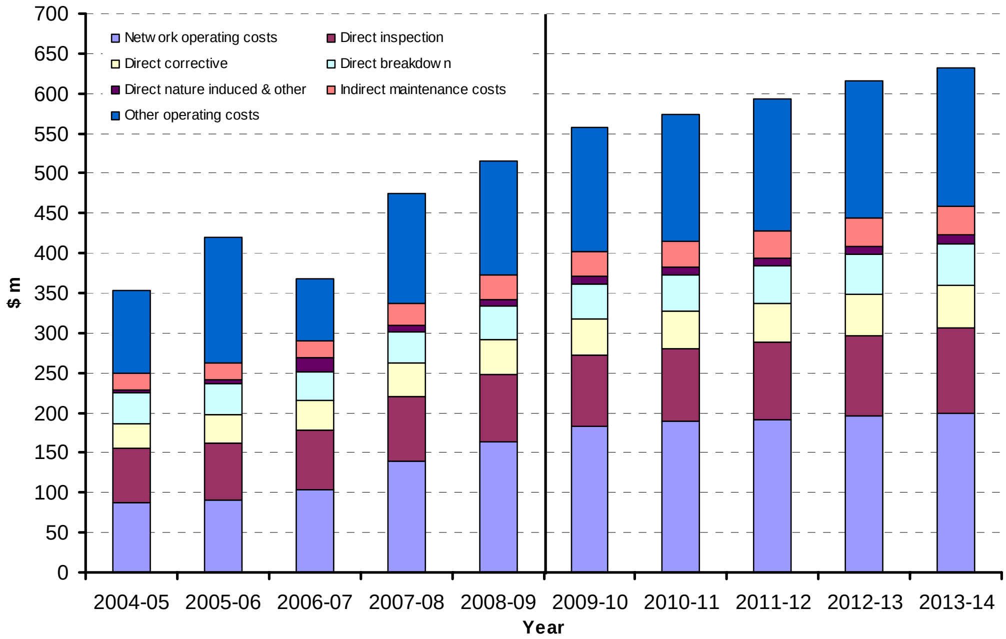
Figure 8.2 shows EnergyAustralia's actual and expected opex in the current regulatory control period, and its forecast opex for the next regulatory control period.

The total controllable opex proposed (after the adjustment) for the next regulatory control period is $2949 million compared with an estimated $2145 million in the current regulatory control period, an increase of 37 per cent. EnergyAustralia indicated that the reasons for the increased level of expenditure include:[467]

- increased workload largely arising from the larger asset base, adding approximately 25 per cent to network maintenance costs
- increased workload due to the increasing age of network assets
- cost increases above inflation
- step changes arising partly from the higher costs of IT from the introduction of new systems and partly from a need to meet statutory and regulatory obligations.

467 EnergyAustralia, *Regulatory proposal*, pp. 133–135.

Figure 8.2: EnergyAustralia's actual and forecast opex 2004–2014 ($m, 2008–09)



Source: EnergyAustralia, RIN opex proforma.

Self insurance and debt and equity raising costs

EnergyAustralia proposed to include $30 million for self insurance costs, $50 million for debt raising costs and $48 million for equity raising costs for the next regulatory control period.[468]

8.3.3 Integral Energy

Table 8.5 sets out Integral Energy's forecast opex by cost category for the next regulatory control period.

Integral Energy's total forecast opex for the next regulatory control period is $1477 million, $345 million (23 per cent) more than its expected actual opex in the current regulatory control period.

[468] EnergyAustralia, PTRM.

Table 8.5: Integral Energy's forecast opex by category ($m, 2008–09)

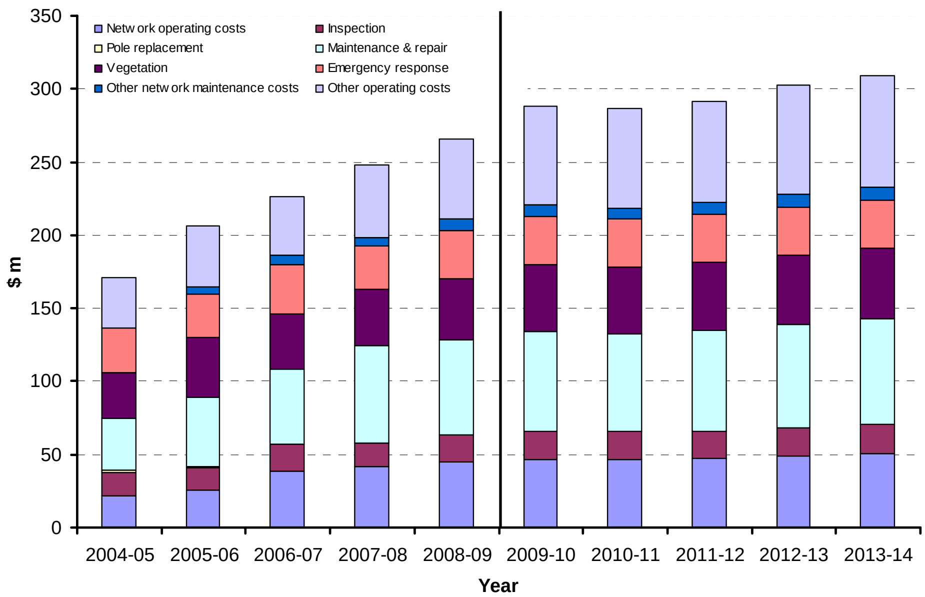
	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Operating and maintenance						
Inspection	16.1	16.2	16.4	16.9	17.4	83.0
Maintenance	102.4	102.9	106.2	108.1	110.5	530.1
Other operating	50.7	50.1	53.3	55.5	58.0	267.9
Corporate support	112.1	110.5	107.7	109.6	110.3	550.2
Total controllable opex	281.3	279.6	283.6	290.2	296.6	1431.3
Self insurance costs	3.2	3.2	3.3	3.3	3.3	16.3
Debt raising costs	3.5	3.8	4.2	4..6	5.0	21.1
Equity raising costs	–	–	–	4.1	4.0	8.2
Total opex	287.9	286.7	291.1	302.2	308.9	1476.8

Source: Integral Energy, *Regulatory proposal*, pp. 128, 140.
Note: Totals may not add up due to rounding.

Controllable opex

Figure 8.3 shows Integral Energy's actual and expected opex in the current regulatory control period, and its forecast opex for the next regulatory control period.

Figure 8.3: Integral Energy's actual and forecast opex 2004–2014 ($m, 2008–09)



Source: Integral Energy, RIN opex proforma.

The total controllable opex proposed for the next regulatory control period is $1431 million compared with an estimated $1132 million in the current regulatory control period, an increase of 26 per cent. Integral Energy indicated that the reasons for the increased level of expenditure include:[469]

- continued real labour cost escalation
- a step change in vegetation management contract costs
- additional apprenticeships, and training for cadets and graduates
- an increase in the size of the asset base
- continued ageing of the asset base
- clearance of a backlog of defects.

Self insurance and debt and equity raising costs

Integral Energy proposed to include $16 million for self insurance costs, $21 million for debt raising costs and $8 million for equity raising costs for the next regulatory control period.[470]

8.4 Submissions

The AER received submissions from the EMRF and EUAA on the NSW DNSPs' opex proposals.

The EMRF noted that the NSW DNSPs' opex allowances increased each regulatory control period and urged the AER to address the claims and ensure they are justified. The EMRF considered that the large capex programs of the NSW DNSPs should allow the DNSPs to provide opex savings in the form of capex/opex trade off and increased productivity savings in general, while opex should only increase where the capex involves new expenditure not replacement expenditure.[471]

The EMRF stated that it is in the interests of the NSW DNSPs to increase capex as they receive a return on capital on that investment whereas opex is recovered on a cost basis only. Further, it stated that from a consumers' viewpoint, it may be more economically efficient to maintain assets through opex rather than pay for increases in capex programs.[472]

The EMRF stated that average wage growth in Australia had been relatively static since the start of the decade. It noted a recent Econtech report provided to the AER had included data that implied that labour cost growth in the electricity, gas and water sector had exceeded average labour cost growth in several selected industries. The EMRF considered that, in an environment of relatively high labour cost growth, DNSPs have been able to control opex spending at the levels provided for by IPART and therefore,

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469 Integral Energy, *Regulatory proposal*, pp. 139–144.
470 Integral Energy, *Regulatory proposal*, p. 13.
471 EMRF, p. 25.
472 EMRF, p. 30.

should not be provided with a premium for expected wages growth in the next regulatory control period.[473]

8.4.1 Country Energy

The EMRF stated that Country Energy proposed a forecast opex allowance in excess of historical opex spending and expected growth in demand.[474]

The EUAA noted the increase in Country Energy's forecast opex for the next regulatory control period. It stated that Country Energy's forecast opex of $429 million is close to a 40 per cent increase over the expected opex in the current regulatory control period of under $300 million. It stated that it was difficult to assess whether the nature of Country Energy's business had changed dramatically enough to warrant the increase.[475]

8.4.2 EnergyAustralia

The EMRF expressed concern about the accuracy of EnergyAustralia's actual opex for 2007–08. It stated that opex rose by $104 million over the previous year, an increase of 30 per cent. Further, the EMRF suggested the EnergyAustralia's claim is inconsistent with conventionally accepted criteria for a step change.[476]

The EMRF also suggested that, given the significant increase in capex projects, the distribution businesses (especially EnergyAustralia) should be required to make larger efficiency savings.[477]

The EUAA suggested that EnergyAustralia had not adequately addressed the issue of efficiency savings in its proposal.[478]

8.4.3 Integral Energy

The EMRF stated that Integral Energy's proposed forecast opex allowance is in excess of historical opex spending and expected growth in demand.[479]

8.5 Consultant review

The AER engaged Wilson Cook to review the controllable opex components of the NSW DNSPs' forecast opex proposals for the next regulatory control period. Wilson Cook reviewed the forecast opex proposals using both a top-down and bottom-up approach.

Wilson Cook's review examined the level of opex as a whole and in the context of the size, characteristics and age of each network and the circumstances of each DNSP. This included benchmarking assessments of the proposed efficient 'base year' opex for each DNSP and of the forecast movements in opex from the efficient base year.[480]

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473 EMRF, pp. 30–31.
474 EMRF, p. 28.
475 EUAA, p. 22.
476 EMRF, pp. 26–27.
477 EMRF, p. 25.
478 EUAA, p. 21.
479 EMRF, pp. 27–28.
480 Wilson Cook, volume 1, p. 15.

Wilson Cook's rationale for this approach was that while each individual project or program may be justified when considered in isolation, it was still necessary that the aggregated opex projection be reasonable. Wilson Cook considered that the aggregation of estimates for individual projects and programmes without adequate consideration of their impact in total, or of cost savings in other parts of the business generally, does not lead to an efficient level of expenditure.[481]

Wilson Cook indicated that its bottom-up review included identification of the basis of the forecasts in each expenditure category; consideration of the main expenditure drivers; identification of the impact of external factors; review of the impact of cost escalation and the treatment of forecast real increases in costs; review of the efficiency of the estimated costs (and of unit costs where relevant); and consideration of the adequacy, efficiency and application of the DNSPs' policies and procedures.

An overview of the reviews by Wilson Cook is provided below. Further details of the reviews are provided at appendices O, P and Q.

8.5.1 Country Energy

Wilson Cook concluded that its top-down analysis (based on comparative benchmarking) suggested that Country Energy's base year level of expenditure is low and may be below a prudent level to maintain targeted service levels.[482]

Wilson Cook proposed one adjustment to Country Energy's opex forecast related to vegetation management. Wilson Cook did not consider that it was appropriate for Country Energy to apply an asset growth escalator to vegetation management, as it was unlikely that the quantity of vegetation management would be driven principally by growth capex. This adjustment resulted in a $30 million reduction to the forecast controllable opex over the next regulatory control period.[483]

8.5.2 EnergyAustralia

Wilson Cook concluded its top-down analysis suggested that EnergyAustralia's base year opex is at or a little above the industry norm, but could not be considered inefficient, although there may be potential for efficiency improvements within the business.[484] However, Wilson Cook indicated that over the next regulatory control period, EnergyAustralia's cost efficiency relative to the other NSW and ACT DNSPs will deteriorate. Wilson Cook indicated that unless reasons can be established why EnergyAustralia should move further away from an industry norm level of opex, then the level of opex in the next regulatory control period cannot be considered to be efficient.[485]

The bottom-up analysis identified a large number of step changes that drive large increases in expenditure. Wilson Cook found that the proposed step changes were not supported by considerations of business efficiency improvements or potential cost savings and therefore were likely to lead to a forecast of future costs that are above an efficient

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481 Wilson Cook, volume 1, p. 15.
482 Wilson Cook, volume 4, p. 42.
483 Wilson Cook, volume 4, p. 41.
484 Wilson Cook did not assess the self insurance costs included in EnergyAustralia's proposed controllable opex.
485 Wilson Cook, volume 2, p. 59.

level. Wilson Cook therefore proposed adjustments to remove most of the step changes proposed by EnergyAustralia.[486]

Wilson Cook indicated that the workload escalators used by EnergyAustralia were generally a reasonable representation of expected workload changes over the next regulatory control period, but recommended minor reductions in relation to maintenance escalation ($18 million) and asset management escalation ($13 million).[487]

In total, Wilson Cook recommended a reduction of $316 million (11 per cent) to EnergyAustralia's opex forecast for the next regulatory control period comprising reductions in:[488]

- network operating costs ($200 million)
- network maintenance costs ($33 million)
- other operating costs ($82 million).

As a check of the recommended opex level derived from the bottom-up analysis, Wilson Cook calculated its own top-down level by applying cost escalation[489] and size escalation[490] to EnergyAustralia's base year opex. Wilson Cook indicated that the top-down opex forecasts were relatively close to the adjusted bottom-up level over the next regulatory period. Wilson Cook therefore recommended that its bottom-up assessment and associated adjustments of EnergyAustralia's proposed opex in the next regulatory control period be accepted.[491]

8.5.3 Integral Energy

Wilson Cook concluded its top-down analysis suggestted that Integral Energy's base year level of expenditure cannot be considered inefficient, but there may be still potential for cost reductions in the business. It noted this potential had been recognised by Integral Energy, which included productivity improvements of 2 per cent per annum, (compounding) over the next regulatory control period in its forecast opex.[492]

Wilson Cook noted that with the effects of real labour cost escalation removed, Integral Energy's opex per size drops by 7 per cent over the next regulatory control period, indicating that Integral Energy's relative costs efficiency is forecast to improve significantly against the other NSW and ACT DNSPs over the next regulatory control period.

486 Wilson Cook, volume 2, pp. 51, 57.
487 Wilson Cook, volume 2, p. 61.
488 Wilson Cook, volume 2, p. 60.
489 Wilson Cook, volume 2, p. 60. Wilson Cook assumed a typical breakdown of opex as being 80 per cent labour related and 20 per cent materials related. The cost escalation was subsequently calculated by applying a 60 per cent weight on the EGW labour rate and a 20 per cent weight on the general wage rate as outlined in the CEG report prepared for the NSW DNSPs.
490 Wilson Cook, volume 2, p. 60. To allow for changes in the size of the business over the period under review.
491 Wilson Cook, volume 2, p. 61.
492 Wilson Cook, volume 3, p. 42.

Wilson Cook identified some adjustments that could be made to the opex forecasts (resulting in a total reduction of approximately $25 million) but concluded that Integral Energy's proposed opex should be accepted without these adjustments on the grounds that the identified adjustments are largely offset by the business adopting aggressive productivity improvement assumptions of its own volition (including reductions in maintenance expenditure from replacement capex that may be overestimated).[493]

8.5.4 Summary

A summary of Wilson Cook's recommended adjustments to the DNSPs' opex forecasts for the next regulatory control period is shown in table 8.6.

Table 8.6: Wilson Cook's recommended forecast controllable opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy's controllable opex forecast	400	408	421	435	451	2116
Wilson Cook's recommended controllable opex	398	405	415	427	441	2086
Difference	2	4	6	8	10	30
EnergyAustralia's controllable opex forecast [a]	555	571	588	610	624	2949
Wilson Cook's recommended controllable opex [a]	496	508	525	545	559	2633
Difference	60	62	63	65	65	316
Integral Energy's controllable opex forecast	281	280	284	290	297	1431
Wilson Cook's recommended controllable opex	281	280	284	290	297	1431
Difference	–	–	–	–	–	–

Source: Wilson Cook, volumes 2, 3 and 4, pp. 60, 43, 42, respectively.
(a) Includes self insurance costs.

Wilson Cook also provided a high level disaggregation of its recommended controllable opex forecasts between EnergyAustralia's distribution and transmission businesses. The recommended expenditures for distribution and transmission are shown in table 8.7.

493 Wilson Cook, volume 3, p. 43.

Table 8.7: Wilson Cook's forecast controllable distribution and transmission opex for EnergyAustralia ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Distribution business	463	476	493	512	526	2471
Transmission business	32	32	32	33	33	162
Total	496	508	525	545	559	2633

Source: Wilson Cook, volume 2, p. 62.
Note: Totals may not add up due to rounding.

8.6 Issues and AER considerations

8.6.1 Controllable opex

The AER engaged Wilson Cook to assist it in assessing the NSW DNSPs' controllable opex forecasts for the next regulatory control. The AER must determine whether the forecast opex of each DNSP reasonably reflects the efficient costs a prudent operator in the circumstances of the DNSP would require to achieve the opex objectives.

The AER considers that the top-down and bottom-up method employed by Wilson Cook to assess the DNSPs' opex forecasts represents an appropriate approach to the assessment of efficient costs, because in combination the assessments ensure that issues are considered comprehensively.

The AER also notes that the majority of the issues raised by the EMRF and EUAA in their submissions are concerns which the AER has taken account of as part of its assessment of the opex proposals. In particular, the submissions expressed concern regarding the large increases in forecast opex for the NSW DNSPs relative to historical expenditure. The AER considers that these concerns have largely been addressed by Wilson Cook's assessment of prudent and efficient costs. In particular, Wilson Cook assessed:[494]

- the appropriateness of the forecasting methods and procedures used by the NSW DNSPs
- the efficiency of the NSW DNSPs' base year opex
- escalations to the base year opex
- step changes in opex, the rationale for those changes and the associated efficiency benefits
- the scope for capex/opex trade offs
- the increase in opex over the next regulatory control period relative to comparable businesses.

[494] Wilson Cook, volume 1, pp. 1, 2, 7, 31–38.

In addition, the AER has undertaken analysis of the appropriateness of other opex components such as the application of cost escalators, self insurance premiums, and debt and equity raising costs. These considerations are set out in sections 8.6.3 and 8.6.4.

An overview of the AER considerations in relation to each of the NSW DNSPs is provided below. Details of the AER's assessment of the NSW DNSPs' forecast controllable opex proposals are set out at appendices O, P and Q.

Country Energy

Efficient base year

The AER notes that Country Energy used 2006–07 as the base year for forecasting its opex requirements. Wilson Cook conducted a benchmarking assessment and concluded that Country Energy's 2006−07 opex represents an efficient level. In addition, Country Energy's 2006−07 opex is very close to the corresponding value in the current IPART determination.[495]

However, the AER notes that Country Energy's opex allowance in the current IPART determination includes a cost pass through amount for works which Country Energy indicated it chose to defer to the next regulatory control period. As a result, Country Energy's 2006−07 base year opex is above the IPART determination since the 2006−07 allowed opex took account of specific services (enhanced vegetation management for poor performing feeder segments) that Country Energy did not undertake. Effectively, in the absence of the IPART pass through allowance, Country Energy would have overspent the IPART opex allowance for 2006−07 by $42 million ($2006−07). As a consequence, the efficiency of the 2006−07 base year must be assessed in the context of the overspend against the IPART allowance. In that context, Wilson Cook noted that:[496]

- at the time of the last determination, Country Energy was a relatively new organisation and may not have had the systems and knowledge to justify an appropriate level of expenditure

- Country Energy's position in the comparative analysis and its over expenditure in the current regulatory control period relative to the IPART determination (excluding the allowance for cost pass through) suggest that the level of opex allowed for in the current regulatory control period may not have been sufficient for it to undertake a prudent level of work.

Based on Wilson Cook's advice, the AER proposes to accept that Country Energy's 2006−07 opex costs represent an efficient base year from which to forecast its future opex requirements.

Network maintenance expenditure

Country Energy forecast maintenance expenditure in the next regulatory control period of $1828 million, compared with $1167 million in the current regulatory control period, an increase of 57 per cent.

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495 Country energy, *Regulatory proposal*, p. 32;
Wilson Cook, volume 4, p. 37.

496 Wilson Cook, volume 4, pp. 34 and 37.

Deferred vegetation management
The AER notes that Country Energy has chosen to defer all enhanced vegetation management for poor performing feeder segments program it put forward in justification of its cost pass through application to IPART in 2005. These programs are now included in its opex forecasts for the next regulatory control period. In the absence of the cost pass through allowance Country Energy would have substantially over spent its regulatory allowance during the current regulatory control period. Based on information provided by Country Energy, in the absence of the cost pass through allowance, expenditure in the current regulatory period would be $135 million ($2008−09) higher than that provided in the IPART determination (i.e. the amount of the proposed cost pass through work program that Country Energy chose to defer).[497] By proposing the reinstatement of the deferred opex, Country Energy is, in effect, seeking an allowance of $135 million which has already been provided for during the current regulatory control period.

The AER has decided not to allow Country Energy to recover the deferred opex in the next regulatory control period. Clause 6.5.6(e)(5) allows the AER to consider the expenditure of a DNSP in the current regulatory control period. In considering the expenditure during the current regulatory control period, the AER notes that Country Energy received an allowance to undertake the enhanced vegetation management for poor performing feeder segments program of works. The AER is therefore not satisfied that Country Energy's opex forecast reflects the efficient costs that a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives.

First, the costs of meeting the opex objectives would not allow Country Energy to receive an allowance for activities for which it has previously received an allowance, because this would not reflect an efficient outcome. Second, the AER is required to consider a prudent operator in the circumstances of Country Energy, which includes the fact that Country Energy has already received an allowance for the enhanced vegetation management for poor performing feeder segments activity. Taking this into account, the AER considers that a prudent operator in the circumstances of Country Energy should not require this allowance again.

The financial consequence of Country Energy deferring the activities provided for in the cost pass through approved by IPART was to limit an overspend Country Energy would have incurred. Hence its operating surplus was greater than it otherwise would have been and the impact on the business of expenditure exceeding the regulatory allowance was removed. While the AER notes the associated expenditure is needed, it is of the view that where customer charges are increased to finance a specific activity in the current regulatory control period, then charges should not be again increased to deliver that service. It would appear more appropriate that this cost be met in the same way as it would if Country Energy had exceeded its regulatory allowance in the current regulatory control period.

The AER notes that the decision to deny the recovery of Country Energy's past opex implicit overspend is consistent with that adopted by IPART in the previous regulatory reset.[498]

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[497] Country Energy, email to AER, 24 October 2008 and 28 October 2008.
[498] IPART, *NSW Electricity Distribution Pricing Final Report*, p. 50.

Based on the decision set out above the AER has removed the deferred expenditure forecasts of $135 million from Country Energy's opex forecasts for the next regulatory control period.

Vegetation management escalation

Country Energy's forecast of the vegetation management component of network maintenance expenditure included an escalation factor for growth in the network. This reflected Country Energy's view that the volume of vegetation management will increase in response to network growth.

Wilson Cook reviewed the expenditure and recommended that the forecast be reduced by $30 million. This reduction reflected Wilson Cook's view that the application of an asset growth escalator to vegetation management was not appropriate.[499]

The AER agrees with Country Energy that there is a positive relationship between network growth and opex. However, the AER agrees with Wilson Cook that it is unlikely that growth capex is the key driver of the quantity of vegetation management required. The AER considers that vegetation management is likely to be more heavily influenced by service quality issues and compliance with licensing and other requirements as demonstrated in the provision of a pass through allowance by IPART in 2005.

Based on its own assessment and Wilson Cook's advice, the AER considers that Country Energy's vegetation management expenditure for the next regulatory control period should be adjusted to reflect the efficient costs a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives, as required by clause 6.5.6(c). The AER's adjustment relates to the removal of the asset growth escalator applied by Country Energy. Following a request from the AER, Country Energy advised that the AER's conclusion results in a reduction of $25 million to its forecast opex.[500]

Conclusion—forecast controllable opex

The AER's adjustments to Country Energy's controllable forecast opex are set out in table 8.8.

The AER notes Country Energy's forecast controllable opex was derived using labour cost escalators for the labour component and generally CPI escalators for non-labour components. These cost escalators are subject to adjustment, as noted in section 8.6.2 of this draft decision, and hence the forecast controllable opex will be further adjusted.

499 Wilson Cook, volume 4, p. 41.
500 Country Energy, response to information request, confidential, 17 November 2008.

Table 8.8: AER's adjustments to Country Energy's controllable opex forecast ($m, 2008–09)

	2009−10	2010−11	2011−12	2012−13	2013−14	Total
Deferred expenditure						
Inspection	–6.2	–6.2	–6.2	–	–	–18.6
Maintenance and repair	–3.0	–3.0	–3.0	–	–	–9.0
Vegetation management	–35.9	–35.9	–35.9	–	–	–107.7
Vegetation management escalation	–1.2	–2.4	–3.8	–7.7	–10.2	–25.3
Total adjustments	–46.3	–47.5	–48.9	–7.7	–10.2	–160.6

Note: Totals may not add up due to rounding.

EnergyAustralia

EnergyAustralia's regulatory proposal included both its transmission and distribution network opex requirements. The transitional chapter 6 rules provide that the AER is required to make a single determination for both EnergyAustralia's transmission and distribution assets. Although EnergyAustralia provided separate tables for distribution and transmission as part of its regulatory proposal, all supporting information is based on its total network opex requirements. As a result, the analysis of opex has been undertaken in total, rather than attempting to consider forecast opex by distribution and transmission separately.

The AER has considered Wilson Cook's review of EnergyAustralia's controllable opex forecast for the next regulatory control period and accepts the recommendation that an adjustment of $316 million should be made. This adjustment reflects Wilson Cook's recommendation to remove the majority of step changes included in EnergyAustralia's controllable opex forecast for the next regulatory control period.

Wilson Cook removed these proposed step changes on the basis that they did not meet its criteria for an acceptable step change. Wilson Cook noted that, in general, a step change should:

- deliver a benefit to customers in terms of the product delivered or to the business in terms of efficiency
- be non-recurring in nature or relate to a fundamental change in the business environment arising from outside factors.

Wilson Cook also considered that the application by EnergyAustralia of workload escalators as well as step changes did not include any consideration of business efficiency improvements and, therefore, has the potential to over-estimate the level of future costs.

The AER considers that the step change criteria adopted by Wilson Cook to assess EnergyAustralia's proposed step changes accord with the opex criteria in that they ensure any step changes reflect the efficient costs a prudent operator would require to achieve the opex objectives.

The AER notes that Wilson Cook's bottom-up assessment of EnergyAustralia's opex forecast for the next regulatory control period is supported by Wilson Cook's top-down approach based on a benchmarking assessment. In particular, Wilson Cook found that EnergyAustralia's 2006−07 base year opex increases at a much higher rate than the other NSW and ACT DNSPs and that over the next regulatory control period, EnergyAustralia's cost efficiency relative to the other NSW and ACT DNSPs will deteriorate.

Wilson Cook calculated its top-down forecast of EnergyAustralia's opex in the next regulatory control period by applying cost and size escalations to EnergyAustralia's base year opex. Wilson Cook indicated that the top-down opex forecasts were 3 per cent lower than the adjusted bottom-up level over the next regulatory control period. Wilson Cook suggested that since its benchmarking analysis indicated that EnergyAustralia was operating at or slightly above the industry norm, the top-down calculation confirms that the adjusted bottom-up level is not unreasonable.

The AER does not consider EnergyAustralia's forecast controllable opex for the next regulatory control period reflects the efficient costs a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives. The AER considers that Wilson Cook's analysis of EnergyAustralia's forecast opex over the next regulatory control period represents a robust assessment and has accepted the recommended adjustments. That is, the revised estimate provided by Wilson Cook reflects the efficient costs a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives, as required by clause 6.6.6(c) of the transitional chapter 6 rules. Accordingly, the AER has accepted Wilson Cook's recommended opex adjustments. Following a request from the AER, EnergyAustralia advised that the AER's conclusion results in a reduction of $328 million to its forecast opex.[501]

The AER's adjustments to EnergyAustralia's controllable forecast opex are set out in table 8.9.

The AER notes EnergyAustralia's forecast controllable opex was derived using labour cost escalators for the labour component and CPI escalators for non-labour components. The labour cost escalators are subject to adjustment, as noted in section 8.6.2, and hence the forecast controllable opex will be further adjusted.

[501] EnergyAustralia, response to information request, confidential, 20 November 2008.

Table 8.9: AER's adjustments to EnergyAustralia's controllable opex forecast ($m, 2008–09)

	2009−10	2010−11	2011−12	2012−13	2013−14	Total
Network operating	–41.2	–44.3	–42.3	–43.6	–42.5	–213.8
Network maintenance	–4.9	–5.5	–6.1	–6.8	–7.6	–30.9
Other expenditure	–14.9	–15.8	–17.1	–17.8	–17.3	–82.8
Total adjustments	–61.0	–65.6	–65.4	–68.2	–67.3	–327.5

Note: Totals may not add up due to rounding.

Integral Energy

In its review, Wilson Cook identified two adjustments to Integral Energy's forecast controllable opex, which amounts to $25 million. The adjustments relate to:

- defect management costs ($9 million)
- other operating costs ($16 million).

While Wilson Cook identified the above opex adjustments, it considered that the total level of controllable opex proposed by Integral Energy should be accepted without adjustment primarily. Wilson Cook was of the view that the identified adjustments are largely offset by Integral Energy adopting aggressive productivity improvement assumptions, which mean its reductions in maintenance expenditure from replacement capex are likely to be overestimated.

The AER accepts that the reductions to defect management expenditure and other operating costs identified by Wilson Cook are appropriate. However, taking account of Wilson Cook's assessment, the AER has considered the efficiency and prudence of Integral Energy's total forecast controllable opex (rather than only the components of that opex). As discussed, the AER considers that Wilson Cook's top-down and bottom-up assessment of the DNSPs' opex forecasts represents an appropriate approach to assessing efficient costs.

The AER considers that applying the Wilson Cook identified adjustments to Integral Energy's forecast opex without consideration of the efficiency of Integral Energy's aggregate opex forecast does not reflect a balanced assessment of efficient costs. Consistent with its approach to the assessment of EnergyAustralia's opex forecasts, the AER has considered both the top-down and bottom-up assessment of Integral Energy's opex forecasts. As such, the AER accepts Wilson Cook's recommendation that Integral Energy's proposed opex is consistent with the requirement of the transitional chapter 6 rules (without making adjustments for defect management expenditure and other operating costs) in light of the ambitious reductions in other areas of forecast opex proposed by Integral Energy.

The AER notes Integral Energy's forecast controllable opex was derived using labour cost escalators for the labour component and CPI escalators for non-labour components.

The labour cost escalators are subject to adjustment, as noted in section 8.6.2, and hence the forecast controllable opex will be adjusted for this reason.

8.6.2 Cost escalators

8.6.2.1 Labour costs

DNSP proposals

EGW escalator

The DNSPs obtained advice from CEG on forecast annual labour escalation rates for the electricity, gas, water (EGW) or utility sector in NSW.[502]

CEG recommended that averaging the escalation rates calculated by Econtech[503] and Macromonitor[504] provides an appropriate forecast of labour cost escalators for the EGW sectors in NSW. The average labour cost escalators adopted by the NSW DNSPs for their forecast opex are set out in table 8.10.

Table 8.10: CEG's real labour cost growth rates for the EGW sector (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Macromonitor (NSW)[a]	4.2	4.4	2.3	-1.2	1.7	3.7	4.2
Econtech (Aus)	2.0	2.8	5.6	5.0	3.9	3.4	3.1
NSW average	3.1	3.60	3.9	1.90	2.80	3.5	3.7

Source: CEG, *NSW electricity businesses*, pp. 7–8.
(a) Productivity adjusted.

General wage escalator

CEG recommended that the NSW DNSPs apply Econtech's forecast for wages across the Australian economy as an appropriate estimate of general labour costs. CEG's proposed general wage forecast is outlined in table 8.11.

Table 8.11: CEG's real labour cost growth rates for general labour (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
General wage	1.8	1.6	2.4	1.9	1.8	2.0	2.0

Source: CEG, *NSW electricity businesses*, April 2008, p. 31.

502 CEG, *Escalation factors affecting expenditure forecasts: a report for NSW electricity businesses*, April 2008;
CEG, *Escalation factors affecting expenditure forecasts: a report for Transend*, April 2008.

503 Econtech, *Labour cost growth forecasts*, 13 August 2007, Attachment D.

504 Macromonitor, *Forecasts of cost indicators for the electricity transmission sector, New South Wales & Tasmania*, February 2008.

Submissions

The EMRF noted that the DNSPs have been experiencing a premium of wages growth over the average wage growth in the current regulatory control period (which is equivalent to the wage forecast recommended by CEG). However, the EMRF stated that at the same time, the DNSPs have tended to maintain their opex at or about the opex allowances granted by IPART in its regulatory determination.[505] The EMRF considered that this implies that there is no basis for escalating the DNSPs proposed opex for expected wages growth, as there is no step change in wages growth between the current and next regulatory control periods.[506]

Consultant review

The AER engaged Econtech to provide advice on wage forecasts for the EGW sector in NSW. In preparing its labour cost forecasts, Econtech took account of the latest available wage data. Econtech also reviewed the CEG methodology for forecasting labour cost growth rates in the EGW sector and concluded that the averaging approach used by CEG was not reasonable.

Econtech's forecasts for labour cost growth rates in the EGW sector in NSW for the next regulatory control period is shown in table 8.12 and outlined in further detail in appendix N.

Table 8.12: Econtech's real labour cost growth rates for the NSW EGW sector (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
NSW	1.2	2.8	3.9	3.4	3.0	2.8	2.1

Source: Econtech, *Labour cost growth forecasts*, appendix D, p. 10.

Econtech also provided advice on general wage forecasts for all industries across Australia. Econtech's general wage forecasts are shown in table 8.13.

Table 8.13: Econtech's real labour cost growth rates for general wages (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Econtech	0.6	1.0	1.1	0.7	0.7	0.8	0.6

Source: Econtech, *Labour cost growth forecasts*, p. 25.

AER considerations

The details of the AER's assessment of the labour cost forecasts proposed by the DNSPs are set out in appendix N.

[505] EMRF, p. 32.
[506] EMRF, p. 32.

EGW wage escalator

The AER considers that where there are real cost increases which are beyond the reasonable control of DNSPs, such cost increases should be factored into a DNSP's revenue proposal to reflect the efficient costs that a prudent operator would require to achieve the opex objectives. In the case of labour, the AER recognises that the shortage of skilled workers in the EGW sector is likely to continue to drive growth in labour costs above CPI in the next regulatory control period.[507] Accordingly, the AER considers that the opex forecasts of the NSW DNSPs should take into account the real increase expected in wages growth in the NSW EGW sector.

Based on Econtech's advice the AER does not consider that the averaging methodology employed by CEG to forecast wages growth in the EGW sector for NSW is sufficiently robust. In particular, the AER notes Econtech's advice that the Macromonitor and Econtech forecasts are not comparable and that averaging the two forecasts is methodologically unsound and likely to provide inappropriate forecasts of labour cost escalation.

Further, the AER does not consider that the CEG proposed labour cost growth rates are a reasonable reflection of the likely future labour costs as they are not based on the most recent information. The AER notes Econtech's advice that since it provided forecasts of labour cost growth rates to the AER in August 2007 (which was used by CEG), the economic climate has changed considerably, resulting in some pressure being taken off wages growth.[508]

For these reasons the AER does not consider CEG's proposed labour cost growth rates for the EGW sector in NSW provide reasonable inputs to deriving the efficient costs a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives.

From 2008–09 the AER will adopt Econtech's forecasts for wages growth in the EGW sector in NSW for the next regulatory control period. The AER considers that the application of the Econtech forecasts for wages growth in the EGW sector for NSW reflects the efficient costs that prudent operators in the circumstances of the NSW DNSPs would require to achieve the opex objectives. Given that actual wage data is available for 2007–08, the AER will apply the actual wage increase provided for under the NSW DNSPs' current work place awards or enterprise bargaining agreements.

The EGW labour cost growth forecasts the AER will apply to the DNSPs opex for the next regulatory control period are shown in table 8.14.

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507 Econtech, *Labour cost growth forecasts*, pp. 36−37.

508 Econtech, *Labour cost growth forecasts*, p. 24.

Table 8.14: AER's conclusion on NSW EGW real labour growth rates (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
AER's EGW labour	−1.4 (CE) 1.4 (EA) 1.5 (IE)	2.8	3.9	3.4	3.0	2.8	2.1

Source: Econtech, *Labour cost growth forecasts,* appendix D, p. 10.
Note: The AER derived the real 2007−08 enterprise bargaining/award rates for Country Energy, EnergyAustralia and Integral Energy by using the actual CPI for 2007–08 of 4.5 per cent.

General wage escalator

The AER accepts that a general labour cost forecast is appropriate to escalate direct labour costs (i.e. other than EGW) incurred by the DNSPs.

A comparison of Econtech's general wage growth forecasts with those recommended by CEG is shown in table 8.15.

Table 8.15: CEG and Econtech's real labour escalators for general wages (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
CEG	1.8	1.6	2.4	1.9	1.8	2.0	2.0	2.02
Econtech	0.6	1.0	1.1	0.7	0.7	0.8	0.6	0.78

Source: CEG, *NSW electricity businesses*, p. 31;
Econtech, *Labour cost growth forecasts*, p. 25.
Note: The average is calculated for 2009–10 to 2013–14.

Given the changes in economic conditions since 2007, the AER does not consider the general wage escalator proposed by the DNSPs are reasonable for the purposes of forecasting labour market wage trends for the next regulatory control period. Accordingly, the AER will apply the updated Econtech general wage escalators to the NSW DNSPs' forecast opex.

Application of labour cost escalators

The NSW DNSPs have outsourced contracts for a number of services included in their forecast opex (e.g. vegetation maintenance and services related to corporate support). Some DNSPs have applied escalation for wages growth under these contracts, while others have not applied escalation for wages growth while rates under these contracts are locked in.

In general, the AER accepts the application of wage rates included in contracts which are negotiated through a commercial tender process. Further, the AER accepts the application of wage rates which reflect the specific circumstances of the service which is being provided. For example, the AER would expect a general wage escalator to be applied to services which are not related to the EGW sector.

Based on the information provided, the AER considers that the application of labour cost escalators by EnergyAustralia and Integral Energy to their forecast opex (subject to the updated Econtech labour cost growth rates being used) reflect a reasonable approach to forecasting opex costs. Following a request from the AER, EnergyAustralia and Integral Energy advised that the AER's conclusions result in a reduction of $0.4 million and an increase of $8.8 million to their respective opex forecasts.[509]

For Country Energy, the AER has made an adjustment to the labour cost forecast used to escalate its vegetation maintenance contracts. Country Energy has applied the EGW labour cost forecast to escalate the contractor costs for vegetation maintenance contracts which are outsourced. Country Energy advised that following a review of its actual contract rates from 2004 to 2007, it decided to adopt the EGW labour cost forecasts to escalate vegetation management contractor costs.[510]

The AER has reviewed the data provided by Country Energy on its vegetation management contractor rates for the 2004–2007 period.[511] Based on the analysis of these contractor rates, the AER found that the average increase in vegetation management contractor rates over this period was 4.3 per annum (nominal). In real terms this equates to an average increase of 1.4 per cent per annum. This increase is more reflective of labour cost growth rates associated with general wages rather than labour cost growth rates for the EGW sector. The AER considers that the general wage escalator is likely to be a more appropriate measure of future labour costs associated with Country Energy's outsourced vegetation maintenance contracts.

Accordingly, the AER will apply the updated Econtech general wage forecasts to the labour component associated with Country Energy's vegetation management contracts. It considers the application of general wage forecasts better reflects the efficient costs that a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives. Following a request from the AER, Country Energy advised that the AER's conclusion (applying updated EGW and general labour cost escalators) results in a reduction of $5.2 million to its forecast opex.[512]

Conclusion

The AER has reviewed the proposed labour cost escalators and considers the Econtech escalators set out in tables 8.14 and 8.15 are appropriate as their application will reflect the efficient costs a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives. Overall, as a result of applying the latest Econtech EGW and general wage growth forecasts, the AER has reduced Country Energy's forecast opex by $5.2 million ($2008−09) and EnergyAustralia's forecast opex by $0.4 million. For Integral Energy the application of the AER's latest labour cost escalators results in an increase to forecast opex of $8.8 million.

The AER has not fully verified the NSW DNSPs' remodelling of cost escalators for the purposes of this draft decision. As such, the adjustments are indicative and will be confirmed for the AER's final decision and determination.

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509 EnergyAustralia, response to information request, confidential, 25 November 2008. Integral Energy, response to information request, confidential, 17 November 2008

510 Country Energy, response to information request, confidential, 27 August 2008.

511 Country Energy, response to information request, confidential, 8 September 2008.

512 Country Energy, response to information request, confidential, 17 November 2008.

8.6.2.2 Non-labour costs

DNSP proposals

The NSW DNSPs proposed the use of CPI to escalate the non-labour component of its opex forecasts.[513] In addition to using CPI, Country Energy has also broken down its forecast opex to determine a weighting for an oil component within the overall non-labour component. It proposed using the CEG crude oil escalator on this component.

AER considerations

The AER considers that EnergyAustralia and Integral Energy's proposed approach of using CPI as escalators—that is, no real increase—for their non-labour opex components to be reasonable and consistent with past regulatory practice, and is therefore accepted.

The AER notes that Country Energy has used CPI to escalate the majority of its non-labour opex. However, for a small proportion of the non-labour component associated with its opex (approximately 4 per cent) Country Energy has used the crude oil escalator. Country Energy has not provided any explanation regarding why it is appropriate to deviate from the CPI and to apply the crude oil escalator to its opex forecast.

The AER considers that the mix of materials used in maintenance works is generally miscellaneous in nature and would expect price movements for such materials to be adequately captured by the CPI. Further, the AER notes that movements in the price of oil would be taken into account with changes in CPI—that is, the price of oil would impact on components of the CPI and thus be reflected in the CPI.

Given the above, the AER is not satisfied that Country Energy's approach, in applying a crude oil escalator to its opex, results in forecast expenditure that reflects the efficient costs a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives. Accordingly, the AER will apply CPI to escalate the non-labour component of Country Energy's opex. Following a request from the AER, Country Energy advised that the AER's conclusion results in a reduction of $2.5 million ($2008–09) to its forecast opex.[514]

8.6.3 Self insurance

DNSP proposals

The NSW DNSPs proposed to include an allowance for self insurance for the next regulatory control period. The NSW DNSPs provided board resolutions to self insure the risks identified in its regulatory proposals.[515] The NSW DNSPs engaged SAHA International Limited (SAHA)[516] to undertake an assessment of the self insurance risks,

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513 Integral Energy, *Regulatory proposal*, p. 145;
EnergyAustralia, *Operational expenditure forecasting –2009 network regulatory proposal*, May 2008, p. 60;
Country Energy, *Cost Escalation Data Spreadsheet*, confidential, 21 July 2008.

514 Country Energy, response to information request, confidential, 17 November 2008.

515 In the case of EnergyAustralia, the AER notes that the Managing Director, and not the board, determines the risk management strategy including self insurance for particular risks.

516 SAHA provides strategic, commercial, economic, corporate finance and financial consulting services. See SAHA website http://www.sahainternational.com/SAHA/SERVICES/pc=PC_90006

and the corresponding self insurance premium associated with these risks.[517] The risks identified and the estimated annual self insurance costs of those risks calculated by SAHA for each of the DNSPs are outlined in table 8.16.

Table 8.16: NSW DNSPs'proposed self insurance premiums for the next regulatory control period ($m, 2008–09)

Risk	Country Energy	EnergyAustralia	Integral Energy
Fraud	0.34	0.67	0.34
Bomb threat, hoax, terrorism	0.06	0.37	–
Earthquakes (< magnitude 7)	0.40	–	1.28
Insurers' credit	0.04	0.03	0.03
Counterparty credit	0.27	0.60	0.39
Bushfire	2.70	2.52	5.90
Risk of non-terrorist impact of planes and helicopters	0.29	0.54	0.69
Damage to towers/poles and lines	1.40	3.82	–
Key assets failure	13.79	13.43	–
Key person risk	0.21	1.10	0.60
General public liability	0.05	0.05	–
Workers compensation	–	5.65	7.12
Guaranteed service level compensation	–	1.25	–
Total (5 years)	19.53	29.52	16.34

Source: SAHA International Limited, *EnergyAustralia self insurance risk quantification*, confidential, final report, 19 May 2008; SAHA International Limited, *Integral Energy self insurance risk quantification*, confidential, final report, 19 May 2008; SAHA International Limited, *Country Energy self insurance risk quantification*, 19 May 2008.

Notes: EnergyAustralia's self insurance premiums in its regulatory proposal were in 2007–08 values. To maintain consistency with EnergyAustralia's opex modelling, the AER has converted these to 2008–09 values using EnergyAustralia's proposed 2.7 per cent escalation rate.
While included as premiums in the SAHA report, Integral Energy did not include in its self insurance allowance, premiums for the following risks: bomb threat, hoax or terrorism events; general public liability; and poles and lines.
Totals may not add up due to rounding.

AER considerations

Details of the AER's assessment of the DNSPs' proposed self insurance allowances are provided at appendix R.

[517] EnergyAustralia, *Regulatory proposal*, Attachment 10.1;
Integral Energy *Regulatory proposal*, appendix O;
Country Energy *Regulatory proposal*, appendix D.

In summary, the AER is satisfied that the DNSPs' proposed allowances for self insurance for the following risks reflect the efficient costs that a prudent operator in the circumstances of the individual DNSPs would require to achieve the opex objectives:

- fraud risk
- insurers' credit risk
- counterparty credit risk.
- key assets risk
- workers compensation.

However, for other risks, the AER is not satisfied that SAHA has provided robust analysis which supports the probability of an event occurring or the costs associated with the event, and therefore the calculation of the self insurance premium.

Accordingly, the AER considers that the DNSPs' proposed self insurance allowances do not reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives, or a realistic expectation of those costs, and has made adjustments accordingly. As a result, the AER has reduced Country Energy's self insurance allowance from $20 million to $15 million, EnergyAustralia's allowance from $30 million to $21 million, and Integral Energy's allowance from $16 million to $10 million ($2008–09) for the next regulatory control period.

As a result of its analysis of the information provided the AER is satisfied that the revised estimate of self insurance costs set out in table 8.17, based on the accepted self insurance premiums detailed in appendix R, reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives.

Table 8.17: AER's conclusion on self insurance allowances for the DNSPs ($2008–09)

	Country Energy		EnergyAustralia		Integral Energy	
	Proposal	AER conclusion	Proposal	AER conclusion	Proposal	AER conclusion
Total self insurance	19.5	15.0	29.5	20.4	16.3	9.6

Note: EnergyAustralia's self insurance premiums in its regulatory proposal are in 2007–08 dollar terms. The AER has converted these to 2008–09 dollar terms using EnergyAustralia's proposed 2.7 per cent escalation.

8.6.4 Debt raising costs

To raise debt, a company has to pay debt financing costs or transaction costs over and above the debt risk premium. Such costs are likely to vary between each debt issue and depend on market conditions.

According to the Allen Consulting Group (ACG) the debt raising cost being considered should be the transaction cost of re-financing fixed rate bonds to the value of the notional gearing component of the regulated firm's regulatory asset base (RAB). The allowed debt benchmark does not relate to:

- acquisitions by the regulated firm
- non-core construction or investment activities that are being undertaken.

Therefore, the transaction costs associated with the benchmark cost of debt should not relate to activities outside of the re-financing of bonds for the regulated firm's core activities.[518]

DNSP proposals

The NSW DNSPs each engaged Competition Economists Group (CEG) to advise them on appropriate costs of raising debt.[519] CEG recommended that the cost of raising debt be set by reference to both direct and indirect costs.

- direct costs—the direct fees charged by the underwriter, credit rating agency, etc
- indirect costs—the cost of issuing capital at a discount in the market to sell it.

CEG noted that the yield to maturity on debt issued by private placement is at least 19 basis points higher than debt issued by public placement. CEG argued that it is a form of cherry-picking for the AER to set interest rates based on debt issued publicly and to restrict debt raising cost estimates to evidence of direct costs in private placement markets by ignoring the higher indirect costs of raising debt in this manner.[520]

CEG recommended that the unit cost of raising debt be set at least equal to 15.5 basis points per annum (bppa) of the amount of debt to be raised.[521] Of this unit cost of 15.5 bppa, 3.0 bppa is included for indirect costs and the remainder represents the direct costs. The NSW DNSPs proposed debt raising cost allowances for the next regulatory control period as follows:

- Country Energy—$24 million ($2008–09)[522]
- EnergyAustralia—$50 million ($2008–09)[523]
- Integral Energy—$21 million ($2008–09).[524]

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518 ACG, *Debt and equity raising transaction costs: final report to the ACCC*, December 2004, p. 5.

519 Country Energy, *Regulatory proposal*, appendix I
Integral Energy, *Regulatory proposal,* appendix P,
EnergyAustralia, *Regulatory proposal,* attachment 8.2.

520 CEG, *Review of nominal risk free rate, debt raising premium and debt and equity raising costs*, pp. 18–19.

521 Integral Energy, *Regulatory proposal*, appendix P, p. 4.

522 Country Energy, *Regulatory proposal*, p. 62.

523 EnergyAustralia, PTRM.

524 Integral Energy, *Regulatory proposal*, p. 128.

AER considerations

The AER uses private debt raising (issuance) costs as a proxy to set an allowance for public debt issuance costs because these costs are not observable in the Australian market. The AER considers that private placements underwriting costs, which forms part of debt issuance costs, are a reasonable proxy for public issuance underwriting costs. This position is supported by the CEG report where it stated 'Livingston and Zhou (2002) find underwriter fees for private placements are not significantly different to public placements'.[525] ACG in its 2004 report for the ACCC also argued that private underwriting costs are a fair proxy for public debt underwriting costs on the basis of the 2002 Livingston and Zhou study.[526]

Overall, the AER is using a publicly available estimate of the debt risk premium on the chosen benchmark firm combined with a publicly available estimate of the debt issuance costs on this benchmark firm. The AER considers these estimates for the debt risk premium and debt issuance costs are the best estimates of the cost of raising public debt currently available. As such, the AER considers that there is no inconsistency or under compensation to firms from using this approach.

CEG's proposed use of the yield from private debt is inconsistent with the efficient benchmark regulated firm that is assumed to be able to issue BBB+ public corporate debt to raise its debt capital.

The AER applies the benchmark BBB+ credit rating with 60:40 debt to equity ratio as specified in 6.5.2 of the transitional chapter 6 rules. It is implicit in the use of this benchmark that the firm can issue public corporate debt in the market at a BBB+ rating and at the average yield to maturity associated with BBB+ public bonds. If firms effectively issue at a higher yield than BBB+, for example due to underpricing the debt, the firms are effectively issuing higher yielding lower grade debt. The proposed underpricing premium is therefore inconsistent with the assumed BBB+ benchmark.

CEG also argued that it is reasonable to assume BBB debt will be more underpriced than the average investment grade debt. CEG has, however, not provided any supporting evidence that BBB+ or even BBB debt is on average issued at a discount (underpriced).

In support of its proposed debt issuance allowance, CEG cited a working paper by Saunder, Palia and Kim (2003) that looked at debt issues in the United States over the period from 1970 to 2000.[527] However, the AER does not consider that this working paper supports the argument that Australian regulated firms are under compensated for the following reasons:

- there is no evidence that the average debt issuance costs of the average US public debt issue is representative of the debt issuance costs of a stable regulated business in Australia. This is even more clearly the case with all regulated firms excluded from the sample used

525 Integral Energy, *Regulatory proposal*—Appendix P, p. 18.
526 ACG, p. 19.
527 Integral Energy, R*egulatory proposal*, Appendix P, pp. 13, 17.

- the working paper indicates that the lowest fifth percentile of firms pay a fraction of the debt issuance costs of the average firm. Using a mean estimate of firms across an economy to estimate debt issuance costs for regulated firms does not appear to be reasonable, given regulated firms should have among the lowest costs of raising debt due to their stable, regulated cash flows. It is also inconsistent with the benchmark used to set the costs of debt generally discussed above.

The current approach of the AER to use private debt issuance costs for Australian companies accessing the private debt markets is therefore considered to provide a better estimate of public debt issuance costs of Australian firms than the study CEG cited by Saunders, Palia and Kim. While the AER acknowledges it has used a proxy for debt issuance costs of public issues, the use of this proxy is more consistent with the assumptions associated with the use of an efficient benchmark regulated firm than the use of figures from the Saunders et al study.

On the basis of the information put forward by the NSW DNSPs, the AER is not satisfied that there is a need to provide indirect debt raising costs under the benchmark regulatory framework, or that the current method used to calculate these costs is under compensating regulated firms. The AER therefore considers that the indirect debt raising costs do not reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives. Accordingly, the AER will maintain its current approach of providing benchmark debt raising costs in accordance with the ACG methodology as applied in previous revenue determinations.[528]

Under this methodology, the ACG based its benchmark on debt raising costs applicable to Australian international bond issues and joint Australian market/international issues and found that the benchmark decreases as the number of bond issues increase.

In developing the benchmark, the ACG calculated a gross underwriting fee benchmark of 5.5 bppa based on a 5-year term. To this amount, it added allowances for legal and roadshow expenses; credit rating fees for the firm and for each issue of bonds; and registry and paying charges. The median bond issue size was determined to be $175 million.

In accordance with the ACG methodology, the AER updated the gross underwriting fee and bond issue size benchmarks using recent publicly available data. This resulted in the gross underwriting fee increasing from 5.5 bppa to 6.0 bppa and the median bond issue size increasing from $175 million to $200 million.[529] Table 8.18 shows the updated build up of debt raising costs and the total benchmark for various bond issues, based on the ACG's methodology.

Country Energy has an opening RAB of $4.2 billion and an assumed benchmark gearing ratio of 60:40. The notional debt component of Country Energy's opening RAB is therefore around $2.5 billion. Based on the ACG methodology, which assumes refinancing of debt with each regulatory determination, this debt size would require around 13 bond issues. As such, the AER considers that an allowance of 8.1 bppa for debt

528 ACG, 2004, pp. 8–13.

529 The latest update by the AER indicates that the gross underwriting fee remains at 6.0 bppa and the median bond issue size remains at $200 million.

raising costs is a reasonable benchmark for Country Energy. Using the PTRM, this benchmark is multiplied by the debt component of Country Energy's opening RAB to provide an average allowance of $2.5 million per annum ($2008–09).

Table 8.18: Benchmark debt raising costs for corporate bond issues (bppa)

Fee	Explanation/source	1 issue	11 issues	13 issues	25 issues
Amount raised	Multiples of median bond issue size	$200m	$2200m	$2600m	$5000m
Gross underwriting fees	Bloomberg for Australian internal issues, term adjusted	6.0	6.0	6.0	6.0
Legal and roadshow	$75k–$100k: industry sources	1.0	1.0	1.0	1.0
Company credit rating	$30k–$50k (once off): S&P ratings	2.5	0.2	0.2	0.1
Issue credit rating	3.5 (2.5) basis points up front: S&P ratings	0.7	0.7	0.7	0.7
Registry fees	$3k/issue: Osborne Associates	0.2	0.2	0.2	0.2
Paying fees[a]	$1/$1m quarterly: Osborne Associates	0.0	0.0	0.0	0.0
Total	Basis points per annum	10.4	8.1	8.1	8.0

Source: AER updated figures based on the methodology in ACG, *Debt and equity raising transaction costs: final report to the ACCC*, December 2004.
(a) Rounded to one decimal place.

EnergyAustralia has an opening RAB of $8.2 billion and an assumed benchmark gearing ratio of 60:40. The notional debt component of EnergyAustralia's opening RAB is therefore around $4.9 billion. Based on the ACG methodology, this debt size would require around 25 bond issues. As such, the AER considers that an allowance of 8.0 bppa for debt raising costs is a reasonable benchmark for EnergyAustralia. This benchmark is multiplied by the debt component of EnergyAustralia's opening RAB to provide an average allowance of $5.1 million per annum ($2008–09).

Integral Energy has an opening RAB of $3.7 billion and an assumed benchmark gearing ratio of 60:40. The notional debt component of Integral Energy's opening RAB is therefore around $2.2 billion. Based on the ACG methodology, this debt size would require around 11 bond issues. As such, the AER considers that an allowance of 8.1 bppa for debt raising costs is a reasonable benchmark for Integral Energy. This benchmark is multiplied by the debt component of Integral Energy's opening RAB to provide an average allowance of $2.1 million per annum ($2008–09).

Table 8.19 shows the AER's conclusion on the debt raising cost allowances for the NSW DNSPs.

Table 8.19: AER's conclusion on debt raising costs ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	2.0	2.3	2.5	2.8	3.0	12.6
EnergyAustralia	3.8	4.5	5.1	5.8	6.4	25.5
Integral Energy	1.7	1.9	2.1	2.3	2.5	10.6

The AER considers the revised benchmark debt raising allowances represent the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives in the next regulatory control period.

8.6.5 Equity raising costs—forecast capital expenditure

An entity incurs equity raising costs when it raises equity capital. These costs may include legal and brokerage fees, and marketing costs. For initial equity raising costs, the fundamental question is whether the RAB has already been determined. The need for access to external equity funds would generally not be expected if the entity were financed in a manner consistent with regulatory benchmark assumptions.

According to the 2004 ACG report, firms finance subsequent capex in the least-cost manner.[530] That is, financing is sourced from retained earnings when possible and that debt financing is preferred to equity financing (this relates to the 'pecking order theory' of capital structure). External equity financing for subsequent capex should be considered only when a case is made that the retained earnings and additional borrowings are insufficient provided that the gearing ratio and other assumptions about financing decisions are consistent with regulatory benchmarks.

DNSP proposals

To determine the amount of equity raising required and based on the recommendation of CEG, the NSW DNSPs applied the cash flow analysis recommended by ACG in its advice to ElectraNet in 2007.[531] This analysis included an assumed dividend yield of 8.0 per cent based on evidence from listed Australian businesses.

Similar to the cost of raising debt, CEG considered that equity raising costs must capture both direct and indirect costs of raising equity. CEG argued that the AER's base equity issuance cost (based on advice from ACG) only estimates the direct costs of raising equity. Therefore, CEG stated that:[532]

> On this basis, the current 3% estimate by the AER is unsustainable. In terms of its derivation this measure only captures underwriting costs – not underpricing cost. As a consequence, it is methodologically flawed. Adding even the lowest estimate of average underpricing (2.54%) would raise the estimated cost to 5.54%.

530 ACG, pp. ix–xii.
531 Integral Energy, *Regulatory proposal*, appendix P, p. 26.
532 Integral Energy, *Regulatory proposal*, appendix P, p. 25.

CEG recommended that the unit cost of raising equity be set at 7.6 per cent of the amount of equity to be raised.[533] The NSW DNSPs have proposed equity raising cost allowances for the next regulatory control period as follows:

- Country Energy—excluded equity raising costs from its building block calculations but stated that they should be determined by the AER based on a unit cost of 7.6 per cent[534]
- EnergyAustralia—$49 million ($2008–09)[535]
- Integral Energy—$8.2 million ($2008–09).[536]

AER considerations

To establish a benchmark allowance for equity raising costs based on the methodology recommended by ACG, two questions need to be answered. First, how much new equity is required to fund forecast capex, and second, what is the benchmark unit cost as a percentage that is to be applied to the equity requirement.[537] Issues underpinning the answers to these questions are discussed in turn below commencing with consideration of indirect equity raising costs.

Indirect cost of raising equity

The AER accepts that underpricing can occur for both initial public offerings and seasoned equity offerings. However the AER does not agree with CEG's proposal that this underpricing or indirect costs need to be included in the benchmark equity raising (issuance) costs allowed in a revenue determination. Even if underpricing for equity raising does occur, the AER considers that:

- no compensation is required for such costs because it would be inconsistent with the benchmark regulatory framework applied to determine the weighted average cost of capital (WACC)
- the efficient benchmark network service provider should be able to raise capital without incurring underpricing costs.

It is assumed by the AER that in setting a benchmark allowance for equity raising costs it is regulating a hypothetical efficient benchmark firm. The efficient benchmark firm should be a large listed firm and while firms may operate under different structures to this, compensation should not be provided for any deviation from the benchmark.

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533 CEG, *Review of nominal risk free rate, debt raising premium and debt and equity raising costs,* p. 4.
534 Country Energy, *Regulatory proposal*, p. 62.
535 EnergyAustralia, PTRM.
536 Integral Energy, *Regulatory proposal*, p. 148.
537 ACG's report to the ACCC in 2004 outlined when additional equity raising may be required, while its report on behalf of Powerlink in 2007 outlined a cash flow analysis method to determine exactly how much equity would be required over the regulatory control period.

The efficient benchmark firm should be able to raise new capital with a seasoned equity offering.[538] Where a firm can undertake a seasoned equity offering, it can use a rights issue where the firm offer shares at a discount to its existing shareholders. This is the most common practice for seasoned equity offerings. In a rights issue, even though the shares are offered at a discount, the firm's existing shareholders benefit from the entire discount and there should be no wealth transfer to new shareholders or loss by existing shareholders. If the existing shareholders do not wish to further invest in the firm they can usually sell their rights (as rights are normally tradable/renounceable and the issuing firm has the option of making them renounceable), or alternatively they can sell some of their existing shares to give them the funds to take up the rights. When viewed in this context, there should be no loss to the firm or its existing shareholders and therefore no requirement to compensate the firm for underpricing.

The efficient benchmark firm is also assumed to be able to raise capital by offering a given return (the awarded WACC). This rate of return implicitly includes compensation for all systematic risk. Therefore, the efficient benchmark firm already includes full compensation for all investor risk that requires compensation under the CAPM and an underpricing allowance—an extra form of compensation for risk for new investors—is not required. The allowed WACC is already determined to be sufficient to induce new investment, and further compensation is unnecessary and inconsistent with the assumptions of the benchmark regulatory framework, and the use of the capital asset pricing model (CAPM). Importantly, the CAPM (a requirement of the NER) assumes all investors have the same required return. This also implies that there should be no allowance for underpricing for new investment.

Finally, CEG has also implicitly argued that as underwriting and underpricing are substitutes, the expected underpricing 'cost' should be paid. This is based on the argument that greater (lesser) underpricing leads to lower (greater) underwriting fees. In relation to this the AER considers that, for traditional underwriting, where the underwriter effectively sells a put option to the issuing firm over some or all of the issue, there is likely to be an inverse relationship between the level of underpricing and the underwriting fee. This is because the lower the strike price on the underwriting option, the lower the probability that the underwriter will incur losses associated with the exercise of the option and therefore the resulting underwriting fee charged.

However, having reviewed equity issuance allowances the AER considers that there are actually strong arguments that the option component of the underwriting fee should not be paid. This is because the underwritten firm should expect to get a payoff with a present value equal to the fair value of the option. Therefore, if anything, CEG's argument appears to support the proposition that the current estimate of direct equity issuance costs should be reduced by the fair value of the option component of the underwriting fee. However, the magnitude of such an adjustment, if required, is yet to be resolved. These matters are the subject of further analysis and investigation by the AER.

538 In relation to Government owned businesses, the guiding principle is that they should be treated the same under competitive neutrality and therefore assumed to be an efficient listed private enterprise that can raise equity through seasoned equity offerings.

Accordingly, the AER has not adjusted the current cost of seasoned equity offering allowances downwards to account for the option component of the underwriting fee in this draft decision.

Based on the information submitted by the NSW DNSPs, the AER is not satisfied that there is a need to take account of the indirect unit cost of raising equity under the benchmark regulatory framework. The AER notes that in its recent transmission price control review, the Office of Gas and Electricity Markets (UK regulator) considered a proposal for an allowance for indirect equity issuance costs. The UK regulator rejected the proposed allowance.[539] Accordingly, the AER will maintain its current approach of using the direct unit cost of raising equity to determine a benchmark equity raising cost allowance when a case for external equity financing associated with forecast capex has been established.

Equity raising requirement—cash flow analysis

The AER has reviewed the DNSPs' proposed benchmark cash flow analysis to establish the requirement for equity raising costs associated with the equity component of its forecast capex over the next regulatory control period.[540] The methodology applied to determine benchmark equity raising costs is summarised by the following steps:

- revenues less expenses (including opex, interest payments and tax) provides the internal cash flow
- internal cash flow less dividends to shareholders provides the retained cash flow
- retained cash flow is used to fund the equity component of capex
- unused retained cash flow, consistent with the pecking order theory, is carried over to the following year to fund the equity component of capex
- equity component of capex less retained earnings (where it is insufficient) indicates the additional equity required
- equity raising cost is then calculated by multiplying the additional equity required with the assumed benchmark transaction cost for subsequent equity issues (discussed below).

This cash flow approach to determining an allowance for equity raising costs was considered by the AER in its recent ElectraNet, SP AusNet and Powerlink transmission determinations to be reasonable and consistent with the principles of benchmark financing arrangements, subject to some adjustments.[541] Similar adjustments are required to each DNSP's proposed cash flow modelling. These are:

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539 Office of Gas and Electricity Markets, *Transmission price control review: Final proposals*, 4 December 2006, p. 59.

540 The AER notes that a summary of the cash flow analysis was included in the CEG reports for Integral Energy and EnergyAustralia. While a cash flow summary was not included in the report for Country Energy, the AER understands that the same methodology was advocated by CEG.

541 AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12: Decision*, 14 June 2007, pp. 99–102.

- 'depreciation' should be referenced to nominal straight-line depreciation (as specified in the 'assets' sheet of the PTRM)

- 'interest payment' should be directly referenced to the row of the 'analysis' sheet of the PTRM which is labelled 'interest payments'.

The AER considers the proposal by CEG to use 'smoothed' rather than 'unsmoothed' revenue (which is based on the timing of costs) in the cash flow analysis is appropriate. Smoothed revenue reflects the expected revenues that the DNSPs are expected to receive.

The AER has removed the impact of capital contributions on the amount of tax payable in the cash flow analysis. This has been done to ensure each of the cash flow items are considered on a 'like for like' basis. It would be inappropriate to include the impact of capital contributions in the tax amount because it is not included in each of the other items that are affected such as revenue and the capex requirement.

The main issue in contention with the cash flow analysis is the assumed amount of dividend payments. The AER has previously assumed a dividend yield of 3.5 per cent, which was based on the average dividend yield of a sample group of Australian companies that were expecting to undertake large capex programs.[542] In a report prepared for TransGrid's revenue proposal, ACG has argued that the AER's assumed dividend yield is inappropriate for the following reasons:[543]

- the AER's sample companies did not have the normal characteristics of regulated utilities, instead having lower gearing levels, lower dividend yields and lower dividend payout ratios

- regulated utilities do not reduce dividends with the purpose of funding capex as they develop an investor clientele with a preference for high dividends. This also has implications for the extent to which dividend reinvestment plans can mitigate the requirement to raise equity.

In its more recent report prepared for TransGrid, ACG advocated a dividend yield assumption of 8.6 per cent, based on the average of 'high yield' utilities calculated by UBS in September 2007. In its reports for the DNSPs CEG applied a dividend yield of 8.0 per cent based on earlier work by ACG.[544]

The AER acknowledges that the sample of firms used to develop a benchmark dividend yield for a TNSP undertaking substantial capex includes companies that in many ways are dissimilar to regulated businesses. However, when it was assessing this issue during the Powerlink revenue reset process, the purpose of the sample companies was specifically to derive a benchmark dividend yield for a firm planning to undertake major capital works. The sample firms shared this key characteristic with Powerlink. The AER notes that the sample firms would ideally include only domestic regulated entities with many similar characteristics to TNSPs, however, such comparators and data were not available.

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542 The AER's cash flow analysis has used RAB value as a proxy for market value to apply the dividend yield assumption. See AER, *Powerlink revenue cap decision*, pp. 99−102.

543 ACG, *Transaction costs of raising equity finance: the dividend yield assumption,* 9 May 2009, p. iv−v.

544 Integral Energy, *Regulatory proposal*, appendix P, p. 29.

The AER has reflected on the use of the dividend yield in the cash flow analysis and notes the following weaknesses with making assumptions about the dividend yield:

- There is a lack of directly comparable firms from which to develop an average dividend yield. While the firms included in the UBS high yield utilities may bear similar characteristics to regulated DNSPs, it is not clear that they are all planning large capital works beyond normal expenditure levels.

- Some of the sample firms in the UBS high yield utilities employ trust business structures which are inconsistent with the benchmark company structure assumed for regulatory purposes. These trust structured firms may have different dividend policies due to their legal structure.

- Dividend payments are made infrequently, generally only twice per annum. The dividend yield assumption is dependent on the market value of the company's equity. For publicly listed firms, this is taken to mean the share price. As the market value of equity may be volatile, reported dividend yields vary from day to day and are beyond the control of a company's management. Furthermore, dividend yields tend to be reported as the most recent 12 months of dividend payments divided by the current share price. These factors may make benchmarked dividend yields an unreliable way to forecast efficient forward looking dividend payments by regulated firms.

It should also be noted that when CEG's recommended dividend yield assumption is applied to the cash flow analysis using the correct depreciation measure, the resultant payout ratio is unsustainable at well over 100 per cent of net profit after tax. [545] This is clearly an unreasonable set of assumptions. Against this however, the AER acknowledges that ACG considered a dividend yield of 3.5 per cent to be inconsistent with the assumed gamma of 0.5, which is specified in the NER.[546]

The AER considers that these problems with the use of the dividend yield outlined above can be overcome by altering the assumptions in the cash flow analysis. Specifically, it is possible to make an assumption with respect to the dividend payout ratio rather than the dividend yield. The dividend payout ratio is the result of an explicit management decision rather than a potentially volatile market measure. It is also a more direct method to establish the amount of retained earnings available for investment and therefore the remaining amount required to be raised as equity. The assumption on the appropriate dividend payout ratio can be made so that the dividend payout ratio is consistent with the gamma value required by the NER.

One could argue that investors expect stable returns in the form of dividends and for that reason management choose an absolute dividend value rather than a portion of profits. Such a strategy could be used to smooth over fluctuations in profit from year to year. However, regulated DNSPs typically earn very stable revenues which mitigate year to year fluctuations that may be observed by the broader market. In other words, there is likely to be little difference in the dividends of a regulated DNSP between specifying the dividend amount and specifying the dividend payout ratio.

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545 As noted above, the correct depreciation measure is nominal straight-line depreciation as specified in the 'assets' sheet of the PTRM.

546 Integral Energy, *Regulatory proposal*, appendix P, pp.26–27.

Accordingly, the AER has decided to amend the cash flow analysis to rely on the assumption of a given dividend payout ratio rather than a given dividend yield. Clause 6.5.3 of the transitional chapter 6 rules deems the assumed utilisation of imputation credits to be 0.5. The AER understands that this value specified in the NER arises from previous analysis and observations of the ACCC. [547] The analysis of the ACCC included an assumption about the appropriate dividend payout ratio in drawing a conclusion on the value to be assumed for gamma or the utilisation of imputation credits. In this regard, the AER considers that a 70 per cent payout ratio is consistent with clause 6.5.3 of the transitional chapter 6 rules. Further, such a payout ratio is consistent with sound management of the benchmark DNSP as a going concern—as opposed to implicitly applying a dividend payout ratio in excess of 100 per cent of earnings.[548]

Based on the respective capex allowances for the DNSPs in this draft decision the AER's modified benchmark cash flow analyses over the next regulatory control period indicate that the total amount of additional equity required is $162 million for Country Energy, $1388 million for EnergyAustralia and $12 million for Integral Energy, as shown in table 8.20 ($nominal). The AER considers these amounts reflect the efficient equity requirements a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives, as required by clause 6.5.6(c).

Benchmark equity raising unit cost

With the amount of equity to be raised specified, an assumption as to the benchmark equity raising unit cost for seasoned equity offerings is required in order to arrive at the total regulatory allowance to be included for equity raising costs.

While CEG recommended the use of the AER's existing benchmark unit cost for direct costs, it recommended a substantial increase in the total unit cost by adding indirect costs. In making its recommendation, CEG had regard to several empirical studies concerning the cost of raising equity. Each of the studies referred to in CEG's report exhibited total costs that were well above the AER's benchmark allowance of approximately 3 per cent. Accordingly, the AER has given consideration to whether the benchmark unit cost it has applied in recent determinations remains appropriate (notwithstanding the fact that CEG's conclusion was that the AER's existing allowance was appropriate for direct equity raising costs).

The benchmark unit cost applied by the AER in its recent determinations comes from the ACG's 2004 report to the ACCC and is based on a sample of Australian firms that ACG considered comparable to regulated entities, notably with their stable cash flow characteristics.

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547 This observation was made in the ACCC's 2004 draft decision for TransGrid, which informed the ACCC's view that the assumed utilisation of imputation credits be 0.5 in the 2004 Statement of Regulatory Principles (SRP). It is also supported by a more recent estimate of the franking credit payout ratio—see Hathaway and Officer, *The value of imputation tax credits – update 2004*, Capital Research Pty Ltd, November 2004. Matters relating to the assumed utilisation of imputation credits are currently under consideration in the context of the AER's WACC review to be finalised in March 2009.

548 As noted, this is the outcome of assuming an 8.6 per cent dividend yield with corrected cash flow analysis that uses the correct measure of depreciation.

Table 8.20: Benchmark capex funding requirement ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy						
Capital expenditure funding	778.6	835.7	882.2	915.5	958.7	4370.8
Debt funding component	467.2	501.4	529.3	549.3	575.2	2622.5
Equity funding component	311.5	334.3	352.93	366.2	383.5	1748.3
Less: retained cash flows	267.6	300.4	308.5	337.9	372.2	1586.6
Additional equity requirement	43.9	33.9	44.4	28.3	11.3	161.8
EnergyAustralia						
Capital expenditure funding	1640.3	1705.0	2001.9	1981.0	1967.0	9295.3
Debt funding component	984.2	1023.0	1201.2	1188.6	1180.2	5577.2
Equity funding component	656.1	682.0	800.8	792.4	786.8	3718.1
Less: retained cash flows	326.4	383.5	457.7	541.5	620.7	2329.7
Additional equity requirement	329.7	298.5	343.1	250.9	166.1	1388.4
Integral Energy						
Capital expenditure funding	597.2	684.3	666.3	648.1	601.7	3197.6
Debt funding component	358.3	410.6	399.8	388.9	361.0	1918.6
Equity funding component	238.9	273.7	266.5	259.3	240.7	1279.0
Less: retained cash flows	235.9	237.1	250.4	263.1	280.6	1267.1
Additional equity requirement	2.9	6.6	16.1	–3.8	–39.9	11.9

Note: Negative sign for the additional equity requirement row indicates that there are sufficient retained cash flows to finance the equity component of capex.

The AER considers that the empirical evidence put forward by CEG is of limited direct relevance to an Australian regulated entity as none of the studies are concerned with the Australian market. The empirical studies are primarily concerned with the US and Europe. Further, it is not clear that the studies assess entities that exhibit similar characteristics to regulated entities (such as stable cash flows), or that they exclude capital raising costs of dissimilar high risk entities.

The AER notes it is possible that the ACG benchmark unit cost for equity raising may overstate the amount that should be provided in a regulatory context. As discussed above, it can be argued that any underwriting fees, which form part of the direct equity raising costs charged for risk compensation of the underwriter for agreeing to take shares if the equity offering is undersubscribed should not be compensated. That is, any option charge component of the underwriting fee should not be compensated as the firm should get fair benefit from these options. These options do not appear to be true transaction costs, rather they appear to be risk compensation for fair risk taken on (i.e. risk transferred to underwriters in return for a fee) and should not be compensated for this reason.

The AER notes that research in this area is ongoing and considers that the approach set out in ACG's 2004 report remains sound for this draft decision. Accordingly, the AER has decided to apply an updated benchmark unit cost of 2.75 per cent for subsequent equity issues.[549] When applied to the additional equity requirement established above, the total amount of benchmark equity raising costs associated with the DNSPs' capex for the next regulatory control period are:

- $4.2 million ($2008–09) for Country Energy
- $36 million ($2008–09) for EnergyAustralia
- $0.4 million ($2008–09) for Integral Energy.

The DNSPs proposed to include equity raising costs under a perpetuity stream as part of their forecast opex allowances. The AER considers that there is merit in treating the equity raising cost allowance as a part of the DNSPs' RABs—that is, to capitalise the allowance. This would improve transparency, given that the nature of the allowance is associated with capex, and ensure that future regulatory resets for the DNSPs would be administratively simpler in the provision of such an allowance.

Further, the AER notes that treating the equity raising cost allowance in perpetuity or in the RAB would be net present value (NPV) neutral. In the 2004 ACG report, it was recommended that equity raising costs be added to the RAB and amortised along with other assets:

> If the regulator has determined that an allowance for the SEO [seasoned equity offering] cost of raising equity for ongoing capital expenditure should be provided for, we recommend that this amount be added to the RAV (i.e. included as part of the capital expenditure cost) and depreciated over the life of the relevant assets.[550]

Accordingly, the amounts specified above will be amortised over the life of the NSW DNSP's RAB for the purposes of providing the equity raising cost allowance associated with the forecast capex over the next regulatory period.[551] This approach is also consistent with the AER's revenue determination for Powerlink.[552]

The AER considers the revised benchmark equity raising allowances associated with the NSW DNSPs' forecast capex represent the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the capex objectives in the next regulatory control period.

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549 In accordance with the ACG methodology, the AER updated the benchmark equity raising unit cost for seasoned equity offerings using publicly available data. This updated cost still includes underwriting fees.

550 ACG, p. xiii.

551 A standard life (of 44 years for Country Energy, 46 years for EnergyAustralia and 43 years for Integral Energy) for amortisation purposes, consistent with each DNSP's weighted average network life, has been assumed.

552 AER, *Powerlink revenue cap decision*, p. 102.

8.7 AER conclusion

8.7.1 Country Energy

The AER has considered Country Energy's forecast total opex of $2160 million ($2008–09), and for the reasons outlined in this draft decision, is not satisfied that the total opex forecast proposed by Country Energy reasonably reflects the opex criteria under clause 6.5.6(c) of the transitional chapter 6 rules. In drawing this conclusion the AER has had regard to the opex factors set out in clause 6.5.6(e) of the transitional chapter 6 rules.

As the AER is not satisfied that Country Energy's total forecast opex reasonably reflects the opex criteria, under clause 6.5.6(d), the AER must not accept the forecast opex in Country Energy's regulatory proposal. Therefore, the AER is required under clause 6.12.1(4)(ii) to provide an estimate of the total opex that Country Energy will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

On the basis of its analysis of Country Energy's proposed opex forecast and the advice of Wilson Cook, the AER has applied a reduction of $185 million to Country Energy's proposed opex. This represents a reduction of around 8.6 per cent of Country Energy's proposed opex of $2160 million and results in a revised forecast total opex allowance of $1975 million.

This revised estimate represents the AER's estimate of the efficient total opex costs that a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives. The AER is satisfied that the revised total forecast opex of $1975 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. This is shown by opex category in table 8.21.

Table 8.21: AER's conclusion on Country Energy's total opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy's controllable opex forecast	400.3	408.4	420.9	435.4	451.0	2116.0
Self insurance costs	3.9	3.9	3.9	3.9	3.9	19.5
Debt raising costs	3.8	4.4	4.8	5.3	5.9	24.2
Country Energy's total opex	408.1	416.7	429.7	444.7	460.7	2159.8
AER's controllable opex	354.9	363.0	373.2	424.1	432.5	1947.7
Self insurance costs	3.0	3.0	3.0	3.0	3.0	15.0
Debt raising costs	2.0	2.3	2.5	2.8	3.0	12.5
AER's total opex	359.9	368.2	378.79	429.9	438.5	1975.2

Note: Totals may not add up due to rounding. The AER will update the opex model with the latest CPI data at a time closer to its final determination.

Table 8.22 sets out the AER's adjustments to Country Energy's forecast controllable opex allowance. These adjustments are derived from the opex model and reflect the AER's conclusion on an efficient controllable opex allowance.

Table 8.22: AER's adjustment to Country Energy's controllable opex ($m, 2008–09)

	2008–09	2009–10	2010–11	2011–12	2012–13	Total
Country Energy's controllable opex	400.3	408.4	420.9	435.4	451.0	2116.0
Adjustment to deferred expenditure	–45.1	–45.1	–45.1	–	–	–135.3
Adjustment to vegetation management escalation	–1.2	–2.4	–3.8	–7.7	–10.2	–25.3
Adjustment to input cost escalators	0.9	2.1	1.2	–3.5	–8.3	–7.7
AER's adjusted controllable opex	354.9	363.0	373.2	424.1	432.5	1947.7

Note: Totals may not add up due to rounding. The AER has not fully verified Country Energy's remodelling of cost escalators for the purposes of this draft decision. As such, the adjustments are indicative and will be confirmed for the AER's final decision.

In addition, the AER will allow Country Energy to capitalise a total of $4.2 million in benchmark equity raising costs for the next regulatory control period.

8.7.2 EnergyAustralia

The AER has considered EnergyAustralia's forecast total opex of $3047 million ($2008–09), and for the reasons outlined in this draft decision, is not satisfied that the total opex forecast proposed by EnergyAustralia reasonably reflects the opex criteria under clause 6.5.6(c) of the transitional chapter 6 rules. In drawing this conclusion the AER has had regard to the opex factors set out in clause 6.5.6(e) of the transitional chapter 6 rules.

As the AER is not satisfied that EnergyAustralia's total forecast opex reasonably reflects the opex criteria, under clause 6.5.6(d), the AER must not accept the forecast opex in EnergyAustralia's regulatory proposal. Therefore, the AER is required under clause 6.12.1(4)(ii) to provide an estimate of the total opex that EnergyAustralia will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

On the basis of its analysis of EnergyAustralia's proposed opex forecast and the advice of Wilson Cook, the AER has applied a reduction of $410 million to EnergyAustralia's proposed opex. This represents a reduction of around 13 per cent of EnergyAustralia's proposed opex of $3048 million and results in a revised forecast opex allowance of $2638 million.

This revised estimate represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives. The AER is satisfied that the revised total forecast opex of $2638 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. This is shown by opex category in table 8.23.

Table 8.23: AER's conclusion on EnergyAustralia's total opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia's controllable opex forecast [a]	555.8	571.1	587.6	610.9	623.4	2948.8
EnergyAustralia's controllable opex forecast (less self insurance costs) [b]	550.0	565.2	581.8	605.1	617.6	2919.7
Self insurance costs	5.8	5.8	5.8	5.8	5.8	29.1
Debt raising costs	7.5	8.7	9.9	11.2	12.5	49.7
Equity raising costs	–	–	16.2	16.2	16.2	48.5
EnergyAustralia's total opex	563.3	579.9	613.7	638.3	652.1	3047.0
AER's controllable opex	490.2	502.8	518.5	535.1	545.3	2591.9
Self insurance costs	4.1	4.1	4.1	4.1	4.1	20.4
Debt raising costs	3.8	4.5	5.1	5.8	6.4	25.5
Equity raising costs	–	–	–	–	–	–
AER's total opex	498.1	511.4	527.6	544.9	555.8	2637.7

Note: Totals may not add up due to rounding. The AER will update the opex model with the latest CPI data at a time closer to its final determination.
(a) Includes self insurance costs.
(b) To ensure comparability with the other DNSPs the AER has restated EnergyAustralia's forecast controllable opex with these self insurance costs removed.

Table 8.24 sets out the AER's adjustments to EnergyAustralia's forecast controllable opex allowance. These adjustments are derived from the opex model and reflect the AER's conclusion on an efficient controllable opex allowance.

Table 8.24: AER's adjustment to EnergyAustralia's controllable opex ($m, 2008–09)

	2008–09	2009–10	2010–11	2011–12	2012–13	Total
EnergyAustralia's controllable opex[a]	555.8	571.1	587.6	610.9	623.4	2948.8
EnergyAustralia's controllable opex forecast (less self insurance costs) [b]	550.0	565.2	581.8	605.1	617.6	2919.7
Adjustment to network operating	–41.2	–44.3	–42.3	–43.6	–42.5	–213.8
Adjustment to network maintenance	–4.9	–5.5	–6.1	–6.8	–7.6	–30.9
Adjustment to other expenditure	–14.9	–15.8	–17.1	–17.8	–17.3	–82.8
Adjustment to labour escalators	1.2	3.2	2.1	–1.8	–5.0	–0.4
AER's adjusted controllable opex	490.2	502.8	518.5	535.1	545.3	2591.9

Note: Totals may not add up due to rounding. The AER has not fully verified EnergyAustralia's remodelling of cost escalators for the purposes of this draft decision. As such, the adjustments are indicative and will be confirmed for the AER's final decision.

(a) Includes self insurance costs.

(b) To ensure comparability with the other DNSPs the AER has restated EnergyAustralia's forecast controllable opex with these self insurance costs removed.

The AER's forecast total opex allowance for the distribution and transmission networks of EnergyAustralia is disaggregated as shown in table 8.25.

Table 8.25: AER's conclusion on EnergyAustralia's opex allowance – distribution and transmission ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Distribution network	466.2	479.7	495.8	512.7	523.7	2478.0
Transmission network	31.9	31.7	31.8	32.2	32.0	159.7
Total opex allowance	498.1	511.4	527.6	544.9	555.8	2637.7

Note: Totals may not add up due to rounding.

In addition, the AER will allow EnergyAustralia to capitalise a total of $36 million in benchmark equity raising costs for the next regulatory control period.

8.7.3 Integral Energy

The AER has considered Integral Energy's forecast total opex of $1477 million ($2008–09), and for the reasons outlined in this draft decision, is not satisfied that the total opex proposed by Integral Energy reasonably reflects the opex criteria under clause

6.5.6(c) of the transitional chapter 6 rules. In drawing this conclusion the AER has had regard to the opex factors set out in clause 6.5.6(e) of the transitional chapter 6 rules.

As the AER is not satisfied that Integral Energy's total forecast opex reasonably reflects the opex criteria, under clause 6.5.6(d), the AER must not accept the forecast opex in Integral Energy's regulatory proposal. Therefore, the AER is required under clause 6.12.1(4)(ii) to provide an estimate of the total opex that Integral Energy will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

On the basis of its analysis of Integral Energy's proposed opex forecast and the advice of Wilson Cook, the AER has applied a reduction of $17 million to Integral Energy's proposed opex. This represents a reduction of around 1.2 per cent of Integral Energy's proposed opex of $1477 million and results in a revised forecast opex allowance of $1460 million.

This revised estimate represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of Integral Energy would require to achieve the opex objectives. The AER is satisfied that the revised total forecast opex of $1460 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. This is shown by opex category in table 8.26.

Table 8.26: AER's conclusion on Integral Energy's total opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Integral Energy's controllable opex forecast	281.3	279.6	283.6	290.2	296.6	1431.3
Self insurance costs	3.2	3.2	3.3	3.3	3.3	16.3
Debt raising costs	3.5	3.8	4.2	4..6	5.0	21.1
Equity raising costs	–	–	–	4.1	4.0	8.2
Integral Energy's total opex	287.9	286.7	291.1	302.2	308.9	1476.8
AER's controllable opex	281.3	283.9	287.9	292.1	295.0	1440.1
Self insurance costs	1.9	1.9	1.9	1.9	1.9	9.6
Debt raising costs	1.7	1.9	2.1	2.3	2.5	10.6
Equity raising costs	–	–	–	–	–	–
AER's total opex	285.0	287.7	291.9	296.3	299.4	1460.3

Note: Totals may not add up due to rounding. The AER will update the opex model with the latest CPI data at a time closer to its final determination.

Table 8.27 sets out the AER's adjustments to Integral Energy's forecast controllable opex allowance. These adjustments are derived from the opex model and reflect the AER's conclusion on an efficient controllable opex allowance.

Table 8.27: AER's adjustment to Integral Energy's controllable opex ($m, 2008–09)

	2008–09	2009–10	2010–11	2011–12	2012–13	Total
Integral Energy's proposed controllable opex	281.3	279.6	283.6	290.2	296.6	1431.3
Adjustment to labour escalators	–	4.3	4.3	1.9	–1.8	8.8
AER's adjusted controllable opex	281.3	283.9	287.9	292.1	295.0	1440.1

Note: Totals may not add up due to rounding.

In addition, the AER will allow Integral Energy to capitalise a total of $0.4 million in benchmark equity raising costs for the next regulatory control period.

8.8 AER draft decision

In accordance with clause 6.12.1(4)(ii) of the transitional chapter 6 rules the AER does not accept Country Energy's proposed opex expenditure for the next regulatory control period. The AER's reasons are set out in section 8.6 of the draft decision. The AER's estimate of Country Energy's required opex for the next regulatory control period is set out in table 8.21 of this draft decision.

In accordance with clause 6.12.1(4)(ii) of the transitional chapter 6 rules the AER does not accept EnergyAustralia's proposed opex expenditure for the next regulatory control period. The AER's reasons are set out in section 8.6 of the draft decision. The AER's estimate of EnergyAustralia's required opex for the next regulatory control period is set out in tables 8.23 and 8.25 of the draft decision.

In accordance with clause 6.12.1(4)(ii) of the transitional chapter 6 rules the AER does not accept Integral Energy's proposed opex expenditure for the next regulatory control period. The AER's reasons are set out in section 8.6 of the draft decision. The AER's estimate of Integral Energy's required opex for the next regulatory control period is set out in table 8.26 of this draft decision.

9 Estimated corporate income tax

9.1 Introduction

This chapter sets out the AER's assessment of estimated corporate income tax liabilities for the NSW DNSPs during the next regulatory control period.

9.2 Regulatory requirements

The AER must make a decision on the estimated costs of corporate income tax to a DNSP in accordance with clause 6.5.3 of the transitional chapter 6 rules. Clause 6.5.3 of the transitional chapter 6 rules provides the following formula for the calculation of the estimated cost of corporate income tax of a DNSP for each regulatory year (ETC_t):

> $ETC_t = (ETI_t \times r_t)\ (1 - \gamma)$
>
> Where:
>
> - ETI_t is an estimate of the taxable income for that regulatory year that would be earned by a benchmark efficient entity as a result of the provision of standard control services if such an entity, rather than the DNSP, operated the business of the DNSP, such estimate being determined in accordance with the post–tax revenue model (PTRM)[553]
> - r_t is the expected statutory income tax rate for that regulatory year as determined by the AER
> - γ is the assumed utilisation of imputation credits and is deemed to be 0.5.
>
> For these purposes:
>
> - the cost of debt must be based on that of a benchmark efficient DNSP (this is done by applying a benchmark cost of debt to a benchmark debt equity ratio)
> - the estimate must take into account the estimated depreciation for that regulatory year for tax purposes, for a benchmark efficient DNSP, of assets where the value of those assets is included in the regulatory asset base (RAB) for the relevant distribution system for that regulatory year.

9.2.1 Transition from pre–tax to post–tax regulation

IPART has previously applied a pre-tax cost of capital in its determinations for the NSW DNSPs. Under the pre-tax approach applied by IPART, an allowance for tax was built into the cost of capital. However the AER must determine a nominal post–tax weighted average cost of capital (WACC) pursuant to clause 6.5.2(b) of the transitional chapter 6 rules. This is discussed in chapter 11 of this draft decision.

Under the post–tax cost of capital required by the NER, an explicit allowance for tax is made on the basis of cashflow analysis rather than including an implicit allowance for tax within the cost of capital (as previously done by IPART). To enable the cashflow

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553 AER, *Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–14: Post–tax revenue model*, Canberra, January 2008; clause 6.4.1 of the transitional chapter 6 rules.

modelling required to estimate the cost of income tax, the remaining tax value of each DNSP's assets (the tax asset base) is required. This information was not required for the pre-tax approach applied by IPART. Accordingly, the tax asset base must be established on transition to the post-tax approach. The AER provided an issues paper on this matter to the NSW DNSPs in June 2007. The issues paper noted that:

> Setting the tax base at commencement of post-tax regulation is important and will have an impact on the calculation of the tax allowance (tax building block). The AER proposes to establish appropriate values for the tax base in light of the specific circumstances of each business. One of the most notable influences concerns business ownership. The proposed approach involves taking the value of a firm's assets for tax purposes when it first became subject to tax, and rolling these values forward to the date when a post-tax approach is to apply, taking account of relevant tax depreciation rules and actual capex and disposals. In the case of government owned businesses, the proposed approach is similar, but utilises the date and tax base when the business became subject to the NTER [National Tax Equivalence Regime]. A key issue for all businesses will be to distinguish RAB assets from non-RAB assets. However, with inflation and the depreciation of existing assets that comes with passing time, the tax base used in the regulatory accounts will become increasingly reflective of the actual tax base of RAB assets.[554]

9.3 NSW DNSP proposals

Each of the NSW DNSPs proposed an allowance for tax calculated by the PTRM, which calculates a tax allowance in accordance with the methodology set out in clause 6.5.3 of the transitional chapter 6 rules. It should be noted that the allowance for tax is an output of the PTRM rather than an input to be specified or proposed by the regulated business. The PTRM was used by each of the NSW DNSPs to calculate the allowance for tax.[555] The relevant inputs to the PTRM's calculation of an allowance for tax include:

- tax remaining life for each asset class
- tax standard life for each asset class
- tax asset base or remaining tax asset value for each asset class

9.3.1 Tax asset base

Each of the NSW DNSPs proposed an opening tax asset base derived in a manner consistent with the AER's preferred approach set out in its issues paper on the transition from pre–tax to post–tax. The NSW DNSPs' proposed tax asset bases for the commencement of the next regulatory control period (as at 1 July 2009) are below:

- Country Energy—$2685 million[556]
- EnergyAustralia—$4962 million[557]

[554] AER, *Issues Paper: Transition of energy businesses from pre–tax to post–tax regulation,* p. 69.
[555] EnergyAustralia entered its forecast tax depreciation of its opening tax asset base (one of the intermediate calculations performed by the PTRM) directly into the PTRM. EnergyAustralia used the PTRM to calculate tax depreciation of forecast capex.
[556] Country Energy, RIN.

- Integral Energy—$2459 million.[558]

9.4 Consultant review

The AER sought the assistance of McGrathNicol to assess the proposals with respect to establishing the opening tax asset base for the NSW DNSPs. Integral Energy and EnergyAustralia submitted draft proposals prior to lodgement which enabled early review by the AER and its consultant. It also enabled both DNSPs to incorporate feedback from the consultant and AER into their formal regulatory proposals.

McGrathNicol gave broad support to the NSW DNSPs' proposals.

9.5 Issues and AER considerations

Each of the NSW DNSPs' estimates of corporate income tax expense comes from the PTRM which performs the calculations required by clause 6.5.3 of the transitional chapter 6 rules.[559] The AER's assessment of the relevant inputs to the PTRM including the tax asset base is set out below.

9.5.1 Standard tax lives and remaining tax lives

DNSP proposals

Country Energy and Integral Energy proposed to apply standard tax and remaining tax lives that are consistent with their respective tax asset registers. These inputs are used by the PTRM to calculate tax depreciation. EnergyAustralia has directly input its own estimate of tax depreciation of its opening tax asset base into the PTRM based on its fixed asset register.[560]

Consultant review

In the context of its review of the opening tax asset base, McGrathNicol noted that the NSW DNSPs derived tax asset values from asset registers, tax working papers and other supporting documentation. The NSW DNSPs' standard tax and remaining tax life inputs to the PTRM are consistent with relevant source material.

McGrathNicol assessed EnergyAustralia's forecast tax depreciation. McGrathNicol noted that the forecast was based on EnergyAustralia's fixed asset register and not inconsistent with rule of thumb estimates.

AER considerations

Country Energy

The AER sought further information from Country Energy regarding remaining tax lives and standard tax lives used both in the PTRM and to establish the opening tax asset base.

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557 EnergyAustralia, RIN.
558 Integral Energy, *Regulatory proposal*, p. 171.
559 The AER notes that EnergyAustralia directly input its tax depreciation amounts into the PTRM. EnergyAustralia outlined its method for calculating tax depreciation on page 150 of its regulatory proposal.
560 EnergyAustralia's tax depreciation of forecast capex has been calculated by the PTRM.

In response, Country Energy stated that all tax standard lives comply with the Taxation Commissioner's recommended tax lives for the various asset categories. It also stated that the remaining lives have been derived by taking the acquisition value and the accumulated depreciation and then multiplying the accumulated depreciation by the standard life to derive the remaining value in terms of years.[561] Accordingly, the AER considers Country Energy's proposed standard tax and remaining tax lives appropriate.

EnergyAustralia

EnergyAustralia outlined its method for calculating tax depreciation on page 150 of its regulatory proposal. The AER notes that EnergyAustralia directly input its tax depreciation amounts for its opening tax asset base into the PTRM and used the PTRM to calculate tax depreciation associated with forecast capex. While EnergyAustralia has not wholly used the PTRM to calculate its forecast tax depreciation concessions, the AER notes the findings of McGrathNicol, that the amounts are not inconsistent with rule of thumb estimates. The AER also notes that the forecast tax depreciation concessions have been calculated using details from its asset register. In doing so, EnergyAustralia's estimate of tax depreciation is based on the depreciation method chosen in its historical tax assessments that is applied to existing assets and the prime cost method applied by the PTRM to forecast capex.[562] The AER considers EnergyAustralia's approach reasonable in the circumstances.

Integral Energy

The AER notes that Integral Energy maintains a tax asset register. Further, Integral Energy has proposed tax depreciation concessions that have been forecast on the basis of relevant rates and methodologies in accordance with tax law and consistent with the requirements of the PTRM.[563] The AER considers that Integral Energy's proposed standard tax and remaining tax lives appropriate.

9.5.2 Establishing the tax asset base—transition from pre–tax to post–tax regulation

NSW DNSP Proposals

The NSW DNSPs presented their respective tax asset bases for RAB and non-RAB assets for each year since the commencement of the NTER. The NSW DNSPs allocated the total tax asset base between RAB-assets and non-RAB assets such as those used as part of the NSW DNSPs' public lighting and retail businesses. Each of the NSW DNSPs made allocations, where relevant, consistent with their agreed cost allocation methods and historical regulatory accounts.

EnergyAustralia's proposed methodology has taken into account the existing tax asset base for its transmission assets which are already regulated under the post-tax approach applied by the ACCC in its last revenue determination. EnergyAustralia's tax records are for the entity as a whole. EnergyAustralia has proposed subtracting the existing

561 Country Energy, email to AER, 18 August 2008.
562 EnergyAustralia, *Regulatory proposa*l, p. 150.
563 Integral Energy, *Regulatory proposal*, p. 170.

transmission tax asset values[564] from the total in order to establish the distribution tax asset value.[565]

EnergyAustralia and Integral Energy presented historical tax asset values for the whole period since becoming subject to the NTER (2001-02). However, Country Energy was only able to present data from 2003-04 onwards due to data limitations prior to the merger with Australian Inland Energy and the introduction of its current financial system. Each of the businesses presented data that aligns with their 2007 tax assessments and forecast the movements between 2007 and 2009 on the basis of forecast capex, disposals and tax depreciation.[566]

Consultant review

The AER sought the assistance of McGrathNicol to assess each of the DNSPs' proposals regarding the opening tax asset base. McGrathNicol found that each of the DNSPs' proposals appeared to be compliant with relevant tax requirements of the NTER, Australian Tax Law and the Australian Accounting Standards. McGrathNicol also noted that tax asset values were generally verifiable through supporting registers, tax working papers and other documentation.

Country Energy

McGrathNicol highlighted some errors with the tax asset base pro forma submitted with Country Energy's regulatory proposal, and requested further information concerning the differences between capex for tax and regulatory purposes, tax lives and the method used to value forecast disposals. Country Energy provided a revised pro forma and further information to address the issues raised by McGrathNicol in an email dated 22 August 2008.

EnergyAustralia & Integral Energy

McGrathNicol did not raise any material issues with respect to EnergyAustralia's and Integral Energy's proposals.

AER considerations

As noted above, the AER requested the NSW DNSPs to present their respective tax asset bases for RAB and non-RAB assets for each year since the commencement of the NTER. The assessment of the tax asset base over the period (as opposed to a single point in time) was intended to ensure that:

- the proposed tax asset base was reflective of the underlying regulatory assets and consistent with regulatory determinations over the period
- there were no transfers of tax assets to other non-regulated business units or related entities.

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564 Among other things such as public lighting tax asset values.

565 EnergyAustralia, *Regulatory proposa*l, appendix 12.1, pp. 3–4 and 10.

566 Country Energy, *Regulatory proposal*, RIN;
EnergyAustralia, *Regulatory proposal*, RIN;
Integral Energy, *Regulatory proposal*, RIN.

The AER considers that the NSW DNSPs' proposals demonstrate that the tax asset base is reflective of its RAB assets and there are no tax asset transfers that would require an adjustment to the opening tax asset base. There are however a range of technical issues which were considered by the AER and its consultant in assessing proposed tax asset bases.

Exclusion of historical capital contributions

The PTRM to apply to the NSW DNSPs for the next regulatory control period explicitly accounts for forecast capital contributions. That is, the forecast value of capital contributions is added to the tax value of assets to be depreciated (for tax purposes) and is also used to calculate forecast total tax expense. Capital contributions do not form part of the RAB.

IPART did not include capital contributions in its estimates of tax payable as its tax allowance was embedded in the WACC allowed for the NSW DNSPs in the current distribution determination. In the current and previous regulatory control periods, each of the NSW DNSPs have been taxed on capital contributions received as if it was revenue. Tax paid on capital contributions created a tax asset to be depreciated and thereby offset future income tax payments. Accordingly, the AER considers it appropriate to exclude historical capital contributions from the opening tax asset base. The inclusion of capital contributions in the tax asset base without any recognition of the tax paid when the capital contributions were received could lead to an inappropriately low regulatory tax allowance.

The NSW DNSPs have excluded capital contributions from their respective opening tax asset bases, which is considered appropriate by the AER.[567]

Inclusion of work in progress

Under the Income Tax Assessment Act, capex translates to a tax asset upon commissioning of the asset. In the PTRM to apply to the NSW DNSPs for the next regulatory control period, capex is recognised on an as-incurred basis. This means that capex creates a notional tax asset in the PTRM when the expenditure is incurred. Accordingly, the AER requested that the NSW DNSPs make an adjustment to the 1 July 2009 opening tax asset base to include work in progress amounts. If that adjustment had not made, the value of work in progress as at 1 July 2009 would never accrue to the regulatory tax asset base. Each of the NSW DNSPs has included the value of work in progress in its opening tax asset base applied in the PTRM.

Data limitations

The AER notes that Country Energy was unable to provide data prior to July 2003. McGrathNicol stated that Country Energy's approach appeared reasonable. The AER accepts McGrathNicol's advice and considers that Country Energy's approach reasonable in the circumstances.

567 The AER notes that Country Energy's regulatory proposal states that capital contributions are included within its opening tax asset base. However, the AER has confirmed with Country Energy that historical capital contributions were not included in its proposed opening tax asset base. See Country Energy, email, 18 August 2008.

Country Energy specific issues

As noted above, Country Energy resubmitted the corrected tax asset base pro forma and further supporting information by email on 22 August 2008. The email provided explanation of the variances between regulatory and tax accounts as well as providing information on Country Energy's method for valuing forecast disposals. The AER considers that Country Energy has adequately addressed the issues raised by McGrathNicol.

EnergyAustralia's allocation of tax asset values between transmission and distribution

The AER considered EnergyAustralia's proposal to allocate the total regulatory tax asset base between its transmission and distribution businesses in March 2008. The ACCC's existing revenue determination for EnergyAustralia's transmission business was made using a post-tax approach. As part of this determination, the transmission tax asset base was used to determine an allowance for corporate income tax during the current regulatory control period. EnergyAustralia has proposed to roll these transmission tax asset values forward to the start of the next regulatory control period. EnergyAustralia has also proposed that the distribution tax asset base be set as the residual of total regulatory tax asset values less transmission and public lighting tax asset values. The AER considers EnergyAustralia's approach appropriate and reasonable.

9.6 AER conclusions

The AER has assessed each of the inputs to the PTRM that are used to calculate the expected cost of corporate income tax in accordance with clause 6.5.3 of the transitional chapter 6 rules. The AER considers that the NSW DNSPs' proposed tax remaining[568] and tax standard lives are appropriate. The AER also considers the NSW DNSPs' proposed opening tax asset bases appropriate and reasonable. On the basis of these inputs, the AER has used the PTRM to calculate the allowance for corporate income tax in accordance with clause 6.5.3 of the transitional chapter 6 rules. The allowances for corporate income tax are presented in table 9.1.

Table 9.1: AER's conclusion on corporate income tax allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	46.2	49.7	43.7	50.9	55.9	246.5
EnergyAustralia	39.2	71.1	81.8	94.4	100.2	386.7
Integral Energy	37.8	39.1	39.3	38.4	41.2	195.9

568 As discussed above, the AER notes that EnergyAustralia has not specified tax remaining lives, instead directly entering its forecast tax depreciation amounts into the PTRM.

9.7 AER draft decision

In accordance with clause 6.12.1(7) of the transitional chapter 6 rules the AER has decided the estimated cost of corporate tax to Country Energy for each regulatory year of the next regulatory control period is specified in table 9.1 of the draft decision.

In accordance with clause 6.12.1(7) of the transitional chapter 6 rules the AER has decided the estimated cost of corporate tax to EnergyAustralia for each regulatory year of the next regulatory control period is specified in table 9.1 of the draft decision.

In accordance with clause 6.12.1(7) of the transitional chapter 6 rules the AER has decided the estimated cost of corporate tax to Integral Energy for each regulatory year of the next regulatory control period is specified in table 9.1 of the draft decision.

10 Depreciation

10.1 Introduction

This chapter sets out the annual allowances for regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB). It also sets out the AER's assessment of the NSW DNSPs' proposed asset lives used to calculate their depreciation schedules for the next regulatory control period.

Regulatory depreciation is used to model the nominal asset values over the regulatory control period and provides the depreciation allowance in the annual revenue requirement. The annual regulatory depreciation allowance is an amortised value of the RAB, derived using a specified depreciation schedule that reflects the nature of the assets over their economic life. Regulatory practice has been to assign a regulatory life (standard or remaining) to each category of assets that equals its expected economic or technical life. Generally, the regulatory, economic and technical lives of an asset coincide.

10.2 Regulatory requirements

Under clause 6.12.1(8) of the transitional chapter 6 rules the AER must make a decision on whether or not to approve the depreciation schedules submitted by a DNSP, in accordance with clause 6.5.5 of the transitional chapter 6 rules. Clause 6.5.5(a) of the transitional chapter 6 rules provides that depreciation must be calculated on the value of the assets included in the RAB at the beginning of the regulatory year.

A building block proposal must contain depreciation schedules that conform to the following requirements set out in clause 6.5.5(b):

> (1) the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets;
>
> (2) the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets (such real value being calculated as at the time the value of that asset or category of assets was first included in the regulatory asset base for the relevant distribution system) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base for the relevant distribution system;
>
> (3) the economic life of the relevant assets and the depreciation methods and rates underpinning the calculation of depreciation for a given regulatory control period must be consistent with those determined for the same assets on a prospective basis in the distribution determination for that period.

To the extent that a DNSP's building block proposal does not comply with the above requirements then the AER must determine the depreciation schedules, in accordance with clause 6.5.5(a)(2)(ii) of the transitional chapter 6 rules.

10.3 NSW DNSP proposals

The NSW DNSPs have proposed to continue the straight-line approach to calculating depreciation in the post-tax revenue model (PTRM). The DNSPs proposed the regulatory depreciation allowances set out in table 10.1.

Table 10.1: DNSPs' proposed regulatory depreciation allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	110.9	138.6	163.7	155.0	147.6	715.8
EnergyAustralia	76.6	103.7	128.1	153.4	147.5	609.3
Integral Energy	115.8	95.3	93.2	86.5	91.4	482.2

Source: Country Energy, *Regulatory proposal*, p. 188; EnergyAustralia, *Regulatory proposal*, p. 23; Integral Energy, *Regulatory proposal*, p. 160.

10.4 Issues and AER considerations

The allowance for regulatory depreciation is an output of the PTRM rather than an input to be specified or proposed by the DNSP. The relevant inputs to the PTRM's calculation of an allowance for regulatory depreciation include:[569]

- remaining life for each asset class
- standard life for each asset class
- existing assets (opening RAB) and new asset values (forecast capex) for each asset class.

10.4.1 Asset classes, standard asset lives and remaining asset lives

Regulatory depreciation has been calculated by the PTRM on the basis of each DNSP's proposed remaining and standard asset life inputs, and the opening RAB (discussed in chapter 5) and forecast capex values.

DNSP proposals

To calculate the regulatory depreciation allowances for their existing assets (by asset classes) the DNSPs applied the remaining asset lives rolled forward from the start of the current regulatory control period.

In calculating the regulatory depreciation allowances for their forecast capex, Country Energy and Integral Energy proposed to maintain the approach applied during the current regulatory control period. As such, their forecast capex values were allocated into the same asset classes and standard asset lives as approved by IPART. EnergyAustralia also proposed to maintain the approach applied during the current regulatory control period and approved by IPART (for distribution assets) and the ACCC (for transmission assets), subject to further disaggregation of its current asset classes.

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[569] Forecast inflation is also a relevant input and is discussed in chapter 11.

EnergyAustralia proposed to introduce four new asset classes driven by technological developments and a desire for greater transparency.[570] Its new assets will be allocated to the proposed new asset classes in order to retain transparency between old and new assets. The proposed new asset classes and standard asset lives are outlined in table 10.2.

Table 10.2: EnergyAustralia's proposed new asset classes and standard lives (years)

Asset class	Standard asset life
Ancillary substation equipment	15
Customer metering (digital)	15
Communications (digital)	10
IT direct system	7

Source: EnergyAustralia, *Regulatory proposal*, p.107.

AER considerations

Country Energy

The AER notes that Country Energy's proposed standard asset lives are the same as those approved by IPART. It considers that they continue to provide depreciation profiles that reflect the nature of those asset classes over their economic lives as required under the NER. Accordingly, the AER accepts these standard asset lives. In reviewing Country Energy's PTRM, the AER found it did not correctly input the standard asset lives set out in its regulatory proposal. The AER has therefore amended the PTRM to correctly input these standard asset lives.

The AER also identified that the asset value for work in progress in Country Energy's opening RAB was not depreciated in the PTRM because an appropriate asset life was not assigned. At the request of the AER, Country Energy reallocated this asset value to other existing asset classes. This had consequential changes to the roll forward of each of the remaining asset lives because they rely on the weights of the relevant asset classes. The AER reviewed Country Energy's reallocation of its work in progress asset values and found it to be appropriate. It also reviewed the updated remaining asset lives and found that they have been appropriately rolled forward for the start of the next regulatory control period.

The remaining and standard asset lives approved by the AER for Country Energy are set out in table 10.3.

[570] EnergyAustralia, *Regulatory proposal*, p. 107.

Table 10.3: Country Energy's approved remaining and standard asset lives (years)

Asset class	Remaining asset life	Standard asset life
Sub transmission lines and cables	25.3	54.9
Distribution lines and cables	36.8	53.8
Substations	21.8	40.2
Transformers	21.4	45.8
Low voltage lines and cables	22.0	51.5
Customer metering and load control	5.9	25.9
Communications	1.8	7.0
Land	n/a	n/a
Easements	n/a	n/a
Emergency spares (major plant, excludes inventory)	8.9	17.9
IT systems	1.9	5
Furniture, fittings, plant and equipment	10.0	13
Motor vehicles	5.1	8
Buildings	48.0	50
Land (non–system)	n/a	n/a
Other non–system assets	0.6	15.0

Source: Country Energy, *Regulatory proposal*, PTRM.

EnergyAustralia

The AER notes that EnergyAustralia's proposed standard asset lives are the same as those approved by the ACCC (for transmission assets) and IPART (for distribution assets), with the exception of four new asset classes and their corresponding standard lives proposed for the next regulatory control period. It considers that these standard asset lives continue to provide depreciation profiles that reflect the nature of those asset classes over their economic lives as required under the NER. Accordingly, the AER accepts these standard asset lives.

In relation to the new asset classes the AER reviewed EnergyAustralia's proposed standard asset lives with the assistance of EMS. For the reasons outlined below, the AER considers the proposed standard asset lives to be reasonable:

- Ancillary substation equipment—The AER notes that new generation electronic equipment does not have the same robustness as older technology electro-mechanical devices. The performance of these devices is critical to the safety and reliability of the electricity network and that electronic devices are known to be more susceptible to supply irregularities such as switching surges and the effects of lightning, despite specification of rigid design and manufacturing standards. Based on EMS's advice, the AER accepts that EnergyAustralia's proposed standard life for this asset class is reasonable.

- Customer metering (digital)—The AER notes that similarly to electronic ancillary substation equipment, digital metering equipment is also known to be more susceptible to supply irregularities such as switching surges and the effects of lightning, despite specification of rigid design and manufacturing standards. Based on EMS's advice, the AER considers EnergyAustralia's proposed standard life for this asset class to be reasonable.

- Communications (digital)—The exact nature of this equipment was not clear from EnergyAustralia's regulatory proposal. Following a request from the AER, EnergyAustralia provided an adequate explanation of the difference between this equipment and ancillary substation equipment. The communications (digital) asset class caters for communication with digital equipment installed within the substation. The equipment is similar in nature to traditional enterprise grade networking equipment, consisting of digital switches and routers that would typically be utilised for computer networking in a medium to large business environment. This equipment differs in both function and technology from traditional ancillary substation equipment. Based on EMS's advice, the AER considers EnergyAustralia's proposed standard life for this asset class to be reasonable.

- IT direct system—The AER notes that this type of equipment requires regular updating and must be supported by suppliers and whose expertise is generally available only in line with the latest technological improvements. Further, the AER agrees that this proposed new asset class will allow improved management of this type of asset. Based on EMS's advice, the AER accepts that EnergyAustralia's proposed standard life for this asset class is reasonable.

During its review of EnergyAustralia's PTRM, the AER identified that the standard asset life for cable tunnel (dx) was not consistent with that set out in its regulatory proposal. This matter was raised with EnergyAustralia and it advised that this was an input error. Accordingly, the AER has amended the PTRM to correct for this input error.

The AER also reviewed the remaining asset lives and found that they have been appropriately rolled forward during the current regulatory control period. The remaining and standard asset lives approved by the AER for EnergyAustralia are set out in table 10.4.

Table 10.4: EnergyAustralia's approved remaining and standard asset lives (years)

Asset class	Remaining asset life	Standard asset life
Transmission & zone land & easements	n/a	n/a
Transmission buildings 132/66 kV	40.8	60.0
Zone buildings 132/66 kV	45.9	60.0
Transmission transformers 132/66 kV	35.5	50.0
Zone transformers 132/66 kV	34.7	50.0
Transmission substation equipment 132/66 kV	28.9	45.0
Zone substation equipment 132/66 kV	31.7	45.0
Transmission and zone emergency spares	40.0	45.0
Ancillary substation equipment (tx)	n/a	15.0
132kV tower lines	21.6	60.0
132kV concrete and steel pole lines	45.2	55.0
132kV wood pole lines	25.2	45.0
132kV feeders underground	24.5	45.0
Cable tunnel (tx)	64.6	70.0
Network control & com systems	19.3	37.2
Communications (digital) (tx)	n/a	10.0
System IT (tx)	n/a	7.0
Sub-transmission lines and cables	27.7	46.3
Cable tunnel (dx)	69.4	70.0
Distribution lines and cables	45.5	58.0
Substations	32.1	46.8
Transformers	27.5	45.9
Ancillary substation equipment (dx)	n/a	15.0
Low voltage lines and cables	35.8	52.1
Customer metering and load control	19.6	25.0
Customer Metering (digital)	n/a	15.0
Communications	8.0	10.2
Communications (digital) – dx	n/a	10.0
Land and easements	n/a	n/a
System IT (dx)	n/a	7.0
Emergency spares (major plant, excludes inventory)	n/a	n/a
IT systems	4.1	5.0
Furniture, fittings, plant and equipment	13.8	17.4
Motor vehicles	8.4	10.2
Buildings	33.2	35.9
Land (non–system)	n/a	n/a
Other non–system assets	12.0	29.4

Source: EnergyAustralia, *Regulatory proposal*, PTRM; AER draft decision PTRM.

Integral Energy

The AER notes that Integral Energy's proposed standard asset lives are the same as those approved by IPART. It considers that they continue to provide depreciation profiles that reflect the nature of those asset classes over their economic lives as required under the NER. Accordingly, the AER accepts these standard asset lives.

In reviewing Integral Energy's PTRM, the AER found that the asset value for work in progress in its opening RAB was not depreciated in the PTRM because an appropriate asset life was not assigned. At the request of the AER, Integral Energy reallocated this asset value to other existing asset classes. This had consequential changes to the roll forward of each of the remaining asset lives because they rely on the weights of the relevant asset classes. The AER reviewed Integral Energy's reallocation of its work in progress asset values and found it to be appropriate. It also reviewed the updated remaining asset lives and found that they have been appropriately rolled forward during the current regulatory control period.

The remaining and standard asset lives approved by the AER for Integral Energy are set out in table 10.5.

Table 10.5: Integral Energy's approved remaining and standard asset lives (years)

Asset class	Remaining asset life	Standard asset life
Sub-transmission lines and cables	19.0	47.4
Distribution lines and cables	33.2	50.6
Substations	20.9	40.0
Transformers	21.9	44.3
Low voltage lines and cables	27.9	52.4
Customer metering and load control	3.9	25.0
Communication	0.5	8.4
Land	n/a	n/a
Easements	n/a	n/a
Emergency spares (major plant, excludes inventory)	9.8	23.6
Information and communication technology	1.4	5.0
Furniture, fittings, plant and equipment	10.7	13.0
Motor vehicles	2.9	8.0
Buildings	48.2	50.0
Land (non–system)	n/a	n/a
Other non–system assets	0.1	12.7

Source: Integral Energy, *Regulatory proposal*, PTRM.

10.5 AER conclusions

The AER has assessed each of the proposed asset class life inputs to the PTRM that are used to calculate the regulatory depreciation allowance in accordance with clause 6.5.5 of the transitional chapter 6 rules. As a result of required adjustments to the asset life inputs to the PTRM for each DNSP, it considers that the DNSPs' proposed depreciation schedules do not comply with the NER requirements and therefore has not approved the schedules under clause 6.12.1(8).

On the basis of the approved asset lives, opening RAB and forecast capex allowance, the AER has determined the DNSPs' regulatory depreciation allowances for the next regulatory control period in accordance with clause 6.5.5(a)(2)(ii), as set out in table 10.6.

Table 10.6: AER's conclusion on regulatory depreciation allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	158.4	169.2	132.7	152.0	172.0	784.2
EnergyAustralia	75.6	102.3	126.2	151.2	145.1	600.3
Integral Energy	137.6	117.0	110.5	102.2	100.4	567.7

10.6 AER draft decision

In accordance with clause 6.12.1(8) of the transitional chapter 6 rules the AER decides not to approve the depreciation schedules submitted by Country Energy. The AER has determined the depreciation schedule for Country Energy is set out in table 10.6 of the draft decision.

In accordance with clause 6.12.1(8) of the transitional chapter 6 rules the AER decides not to approve the depreciation schedules submitted by EnergyAustralia. The AER has determined the depreciation schedule for EnergyAustralia is set out in table 10.6 of the draft decision.

In accordance with clause 6.12.1(8) of the transitional chapter 6 rules the AER decides not to approve the depreciation schedules submitted by Integral Energy. The AER has determined the depreciation schedule for Integral Energy is set out in table 10.6 of the draft decision.

11 Cost of capital

This chapter sets out the AER's estimate of an efficient (market-based) benchmark weighted average cost of capital (WACC) or the rate of return for the NSW DNSPs for the next regulatory control period. The key issues considered include the WACC parameters specified in the transitional chapter 6 rules, and the determination of the risk-free rate, debt risk premium and inflation forecast.

The AER's consideration of debt and equity raising costs, and corporate tax allowances is not set out in this chapter because they are not compensated for through the WACC. Accordingly, the analysis of debt and equity raising costs is found in chapter 8 and the analysis of corporate tax is found in chapter 9 of this draft decision.

11.1 Regulatory requirements

Clause 6.5.2 of the transitional chapter 6 rules requires that the return on capital be calculated by applying the rate of return to the value of the regulatory asset base (RAB) as determined in chapter 6 of this draft decision.

The AER must determine the rate of return in accordance with clause 6.5.2 of the transitional chapter 6 rules. Clause 6.5.2(b) provides that the rate of return for a DNSP is a nominal post-tax WACC calculated in accordance with the following formula:

$$\mathrm{WACC} = \mathrm{k_e}\frac{E}{V} + \mathrm{k_d}\frac{D}{V}$$

where:

k_e = the return on equity

k_d = the return on debt

E/V = the market value of equity as a proportion of the market value of equity and debt, which is 1 – D/V

D/V = the market value of debt as a proportion of the market value of equity and debt, which is deemed to be 0.6.

It also states that the return on equity (k_e) is determined by using the capital asset pricing model (CAPM):

$$k_e = r_f + \beta e \times MRP$$

where:

r_f = the nominal risk-free rate of return for the regulatory control period determined in accordance with clause 6.5.2(c)

MRP = the market risk premium, which is deemed to be 6 per cent

β_e = the equity beta which is deemed to be 1.

It also states that the return on debt (k_d) is calculated as:

$k_d = r_f + DRP$

where:

DRP = the debt risk premium for the regulatory control period is determined in accordance with clause 6.5.2(e).

11.2 NSW DNSP proposals

In estimating the WACC for their regulatory proposals, the NSW DNSPs have used the values for the WACC parameters set out in the transitional chapter 6 rules. The nominal vanilla WACC proposed by each DNSP and the parameters underlying the calculation of each are presented in table 11.1.

Table 11.1: DNSP proposed WACC parameters

Parameter	Country Energy	EnergyAustralia	Integral Energy
Risk–free rate (nominal)	6.09%	6.09%	6.09%
Risk–free rate (real)	3.46%	3.46%	3.46%
Expected inflation rate	2.54%	2.54%	2.54%
Debt risk premium	2.11%	2.11%	2.11%
Market risk premium	6.00%	6.00%	6.00%
Gearing	60.0%	60.0%	60.0%
Equity beta	1.00	1.00	1.00
Nominal pre–tax return on debt	8.20%	8.20%	8.20%
Nominal post–tax return on equity	12.09%	12.09%	12.09%
Nominal vanilla WACC	9.76%	9.76%	9.76%

Source: Country Energy, *Regulatory proposal*, p. 162; EnergyAustralia, *Regulatory proposal*, p. 109; Integral Energy, *Regulatory proposal,* p. 169.

11.3 Submissions

The Energy Markets Reform Forum (EMRF) noted that the NSW DNSPs have proposed significantly increased capital programs which could put pressure on financial markets and increase the cost of debt and equity. The EMRF argued that the AER should not, in recognition of this, set the CAPM inputs higher than it otherwise would as this 'would not be in the long term interests of consumers'.[571]

571 EMRF, p. 34.

11.4 Issues and AER considerations

Businesses are typically funded by a combination of equity and debt. Therefore, a weighted average cost of equity and debt must be established to derive the rate of return. This is usually referred to as the WACC. The derivation of the WACC requires several parameters. Many of these parameters have values specified in the NER. Where the NER does not specify a value, it specifies a method for determining the value.

11.4.1 The WACC parameters specified in the NER

The NER specifies values for the equity beta and the market risk premium to be used to calculate the return on equity using the CAPM. The NER also specifies the value of debt as a proportion of the value of equity and debt (or gearing) to be used when calculating the WACC.

NSW DNSP proposals

The NSW DNSPs have estimated the return on equity using the CAPM and adopted the parameter values specified in the NER for the equity beta, market risk premium (MRP), and proportion of debt funding (gearing).[572]

AER considerations

Based on the NER requirements, the parameters and values as outlined in section 11.2 of this draft decision have been applied by the AER for the purposes of determining the WACC for the NSW DNSPs.

11.4.2 The risk free rate

The risk-free rate measures the return an investor would expect from an asset with zero volatility and zero default risk. The yield on long-term Commonwealth Government Securities (CGS) is often used as a proxy for the risk-free rate because the risk of government default on interest and debt repayments is considered to be low.

In the CAPM framework, all information used for deriving the rate of return should be as current as possible. While it may be theoretically correct to use the on-the-day rate as it represents the latest available information, this can expose the DNSP to day-to-day volatility. For this reason, an averaging method is used to minimise volatility in observed bond yields.

Regulatory requirements

Clause 6.5.2(c) states that the nominal risk-free rate is to be determined by the AER:

> … on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years using:
>
> (1) the indicative mid rates published by the Reserve Bank of Australia; and
>
> (2) a period of time which is either:

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[572] Country Energy, *Regulatory proposal*, p. 162;
EnergyAustralia, *Regulatory proposal*, p. 109;
Integral Energy, *Regulatory proposal*, p. 169.

> (i) a period ('the agreed period') proposed by the relevant Distribution Network Service Provider, and agreed by the AER (such agreement is not to be unreasonably withheld); or
>
> (ii) a period specified by the AER, and notified to the provider within a reasonable time prior to the commencement of that period, if the period proposed by the provider is not agreed by the AER under subparagraph (i),
>
> and, for the purposes of subparagraph (i):
>
> (iii) the start date and end date for the agreed period may be kept confidential, but only until the expiration of the agreed period; and
>
> (iv) the AER must notify the Distribution Network Service Provider whether or not it agrees with the proposed period within 30 business days of the date of submission of the building block proposal. [573]

Clause 6.5.2(d) states that if there are no CGS with a maturity of 10 years on any day in the averaging period, the AER must determine the nominal risk-free rate by:

> … interpolating on a straight line basis from the two Commonwealth Government bonds closest to the 10 year term and which also straddle the 10 year expiry date.

NSW DNSP proposals

The NSW DNSPs have nominated averaging periods to calculate the risk-free rate of the lengths outlined in table 11.2 below. Indicative risk-free rates proposed for the purpose of their proposals are also outlined in table 11.2 for each DNSP. The NSW DNSPs noted that the AER will determine the applicable risk-free rate in its final distribution determination using market data from the averaging periods nominated by the DNSP.

Table 11.2: NSW DNSP proposed risk free rate and averaging period

Parameter	Country Energy	EnergyAustralia	Integral Energy
Risk–free rate (nominal)	6.09%	6.09%	6.09%
Averaging period length (business days)	10 or 15	15	15

Source: Country Energy, *Regulatory proposal*, p. 162; EnergyAustralia, *Regulatory proposal*, attachment 8; Integral Energy, *Regulatory proposal*, p. 169.

AER considerations

Clause 6.5.2(c) of the NER requires the AER to determine the nominal risk-free rate using annualised CGS yields with a maturity of 10 years.

In accordance with clause 6.5.2(c) the NSW DNSPs proposed averaging periods to estimate the risk-free rate. The AER did not agree with the periods proposed on the basis that it considered the proposed dates of the periods were too far removed from the final determination date and the commencement of the regulatory control period. A period that is too far removed from the final determination date may not provide the most relevant

573 Transitional chapter 6 rules, clause 6.5.2(c).

information. This is consistent with past practice by the AER and other state regulators, and supported by CAPM theory.[574]

The AER advised the DNSPs that it did not agree with the proposed averaging periods and proposed a period closer to the final determination date. As an alternative the AER gave the DNSPs the option of proposing a new averaging period within a period of time specified by the AER. Integral Energy agreed with the averaging period specified by the AER. Country Energy responded with new proposed starting and ending dates for the averaging period (based on an averaging period of 15 business days). EnergyAustralia nominated an averaging period within the period of time specified by the AER but stated that it did not agree with the AER's decision or its supporting reasons. The AER has accepted the averaging periods nominated by Country Energy and EnergyAustralia as it considers the 15 day averaging period and revised dates address its earlier concerns. The AER has agreed to keep the start and end dates of the averaging periods confidential until the expiration of the period as requested by the NSW DNSPs.

For this draft decision, the 15 day moving average for CGS yields with a 10-year maturity for the period ending 17 October 2008 results in a proxy nominal risk-free rate of 5.34 per cent (effective annual compounding rate).[575] The AER will update the risk-free rate, based on the AER's specified averaging period, at the time of its final decision.

11.4.3 The debt risk premium

The debt risk premium (or debt margin) is added to the nominal risk-free rate to calculate the return on debt, which is an input for calculating the WACC. The debt risk premium is the margin above the risk-free rate that investors in a benchmark efficient DNSP are likely to demand as a result of issuing debt to fund the business operations. It is intended to equate to a commercial cost of debt.

The debt risk premium varies depending on the entity's operational and financial risk as well as the term of the debt. This can be characterised as a credit rating. Applying the return on debt (as a percentage) to the RAB, adjusted for the assumed gearing, will generate the interest expense for regulatory purposes (also referred to as the cost of debt).

Regulatory requirements

Clause 6.5.2(b) states that the return on debt (k_d) is calculated as:

$$k_d = r_f + DRP$$

Where:

r_f	=	the nominal risk-free rate
DRP	=	the debt risk premium for the regulatory control period determined in accordance with clause 6.5.2(e).

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574 Lally, Martin, *The cost of capital for regulated entities*, report prepared for the Queensland Competition Authority, 26 February 2004, p. 63.
Davis, Kevin, *Report on risk free interest rate and equity and debt beta determination in the WACC*, report prepared for the ACCC, 28 August 2003, p. 16.

575 RBA, CGS yields, at: www.rba.gov.au/statistics/indicative.html.

Clause 6.5.2(e) of the transitional chapter 6 rules states that the debt risk premium is:

> … the margin between the 10 year Commonwealth annualised bond rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity of 10 years and a credit rating of BBB+ from Standard and Poors.

NSW DNSP proposals

Based on the NER requirements for setting the debt risk premium and using Bloomberg data, the NSW DNSPs have all proposed a debt risk premium of 2.11 per cent. The NSW DNSPs have recognised that the AER will determine the debt risk premium in its final determination using updated market data from the averaging periods nominated by the DNSPs.[576]

EnergyAustralia submitted that long-term corporate bond data observations should be sourced from the Bloomberg service and that the AER adopt the same estimation techniques it employed in its recent transmission determination for SP AusNet.[577] Integral Energy considered that the approach adopted by the AER appears reasonable.[578]

AER considerations

In previous revenue determinations the AER conducted a review which compared the estimated average daily fair yields for corporate bonds with BBB+ credit rating and maturity of up to 10 years from the Bloomberg and CBASpectrum databases over a period.[579] Differences between the average yields for actual bonds with the estimated average fair yields from the two databases were observed. The review indicated that Bloomberg provides estimates of BBB+ rated long-term fair yields, which are more consistent with the observed yields of similarly rated actual bonds. The AER has therefore decided to use the fair yields estimated by Bloomberg, rather than CBASpectrum, for determining the benchmark debt risk premium margin for the NSW DNSPs.

The AER has previously used BBB 10-year corporate bond fair yields sourced from Bloomberg for the purposes of establishing a 10-year benchmark debt risk premium with a BBB+ credit rating.[580] In late October 2007, Bloomberg ceased publication of its BBB fair yields for bonds with 9 or 10-year maturities. The AER understands that the decision to cease publication was based on a lack of data for these long-dated corporate bonds (within the BBB credit rating category) from which Bloomberg could produce a fair yield. The longest maturity BBB bond fair yield now published by Bloomberg is 8 years.

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576 Country Energy, *Regulatory proposal*, p. 161; EnergyAustralia, *Regulatory proposal*, p. 109; Integral Energy, *Regulatory proposal*, pp. 169–170.

577 AER, *Final decision: SP AusNet transmission determination 2008–09 to 2013-14*, January 2008.

578 EnergyAustralia, *Regulatory proposal*, p. 109; Integral Energy, *Regulatory proposal*, p. 166–167.

579 AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, Draft Decision, 8 December 2006, pp. 103-104; and
AER, *Directlink Joint Venturers' application for conversion and revenue cap*, Decision, 3 March 2006, pp. 211, 221.

580 Bloomberg's BBB fair yields are assumed to approximate BBB+ fair yields due to the estimation technique employed and the market being disproportionately weighted with longer term BBB+ rated bonds.

Due to the unavailability of the Bloomberg fair yields for BBB rated 10-year corporate bonds, it is necessary to adopt an alternative proxy for deriving a 10-year BBB+ benchmark debt risk premium, as required by the NER.[581] The AER recently considered this issue and the details are set out in its final decision on the SP AusNet transmission determination.[582] Specifically, the methodology applied by the AER is to take the Bloomberg fair yield for BBB rated 8-year corporate bonds and add the Bloomberg fair yield spread between A rated 8 and 10-year corporate bonds, in order to derive a proxy 10-year BBB+ corporate bond yield. The AER considers that this methodology remains appropriate for the purposes of determining the benchmark debt risk premium.

Consistent with previous regulatory practice, the AER considers that the debt risk premium should be determined with reference to the same averaging period that was adopted for determining the risk-free rate. For this draft decision, the 15-day moving average benchmark debt risk premium for the period ending 17 October 2008, based on BBB+ rated corporate bonds with a maturity of 10 years, is 3.29 per cent (effective annual compounding rate).[583] Adding this debt risk premium to the nominal risk-free rate of 5.34 per cent provides a nominal return on debt of 8.63 per cent. The AER is satisfied that the debt risk premium is consistent, under clause 6.5.2(e), with the required margin between the 10-year CGS yield and observed Australian benchmark corporate bond yields corresponding to BBB+ credit rating and maturity of 10 years.

The debt risk premium will be updated by the AER based on this methodology at the time of its final decision. As outlined above in relation to the risk-free rate, the AER did not agree with the averaging period originally nominated by the NSW DNSPs and has substituted alternative averaging periods to use in its calculations for the final decision.

11.4.4 Expected inflation

The expected inflation rate is not an explicit parameter within the WACC calculation. However, it is used in the post-tax revenue model (PTRM) to forecast nominal allowed revenues. It is an implicit component of the nominal risk-free rate, with implications for the return on both equity and debt. The PTRM framework essentially provides a real rate of return to the business, which means that the expected inflation rate included in the nominal WACC must be appropriately measured.

Regulatory requirements

Clause 6.4.2(b)(1) states that the PTRM must specify:

> … a method that the AER determines is likely to result in the best estimates of expected inflation.

Historically, the AER has used an objective market-based approach to forecast the expected inflation rate—calculated as the difference between the CGS (nominal) and the indexed CGS yields. However, since late 2006 a downward bias in the indexed CGS has become evident due to the limited supply of these securities. Consequently, using this

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581 The proxy corporate bond yield less the risk-free rate produces the debt risk premium.
582 AER, *SP AusNet transmission determination,* pp. 94–98.
583 Bloomberg's BBB fair yields are assumed to approximate BBB+ fair yields due to the estimation technique employed and the market being disproportionately weighted with longer term BBB+ rated bonds.

method potentially yields an overestimate of expected inflation. This limitation was recognised in the AER's PTRM guideline for DNSPs published in January 2008.[584] The PTRM guideline states that:

> …the AER considers the appropriate methodology for deriving forecast inflation would incorporate the forecasts and target inflation range of the Reserve Bank of Australia.[585]

In its recent final determinations for ElectraNet and SP AusNet, the AER applied the RBA's short-term inflation forecasts for the first two years of the next regulatory control period and adopted the mid-point of its target inflation band (that is, 2.5 per cent) for the remaining eight years. An implied 10-year forecast is derived by averaging these individual forecasts. This aligns the inflation forecast to the term of the risk-free rate.[586]

NSW DNSP proposals

The NSW DNSPs all proposed a ten year forecast of annual inflation of 2.54 per cent per annum.[587]

The NSW DNSPs jointly commissioned CEG to advise on the best approach to forecasting inflation. CEG recommend that the best estimate of expected (mean) inflation over a 10 year period is obtained from a weighted average mean of professional economic forecasters' short and long term expectations, yielding an inflation rate of 2.54%.[588]

AER considerations

The AER has determined in previous transmission determinations that a method that is likely to result in the best estimate of inflation over a 10-year period is to apply the RBA's short-term inflation forecasts—currently extending out to two years—and adopt the mid-point of its target inflation band beyond that period (i.e. 2.5 per cent) for the remaining eight years. An implied 10-year forecast is derived by averaging these individual forecasts.

The inflation forecasting methodology proposed by the NSW DNSPs in their revenue proposals is broadly similar to that applied by the AER for its previous transmission determinations.[589] The difference between the two approaches, however, is the range of sources used to establish the 10-year average inflation estimate. The NSW DNSP's proposed methodology draws on forecasts from a number of independent economic forecasters,[590] while the AER's approach in previous transmission determinations relies on the RBA's inflation forecasts and the mid-point of its target band.

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[584] AER, *PTRM: final decision,* 1 January 2008, p. 10.

[585] AER, *PTRM: final decision,* 1 January 2008, p. 10.

[586] AER, *ElectraNet transmission determination 2008–09 to 2012–13: Final Decision*, 11 April 2008, pp. 68–70.
AER, *SP AusNet transmission determination* pp.99–106.

[587] Country Energy, *Regulatory proposal*, p. 162;
EnergyAustralia, *Regulatory proposal*, p. 22;
Integral Energy, *Regulatory proposal*, pp. 167–169.

[588] CEG, *Expected inflation estimation methodology,* pp. 6–11.

[589] AER, *ElectraNet transmission determination*, p. 69.
AER, *SP AusNet transmission determination,* pp. 99–106.

[590] CEG, *a report for NSW electricity businesses,* p. 6.

The AER notes the RBA's responsibility for monetary policy in Australia means it is an independent authority on inflation expectations. The AER considers that the RBA's inflation forecasts are objective and represent the best estimates of forecast inflation for the purpose of this draft decision. The RBA's statement on monetary policy examines a wide variety of objective data influencing inflation in both the domestic and international financial markets to develop its inflation forecast. The forecast is produced on a regular basis and is publicly available, including supporting analysis and reasoning. The AER's approach uses the RBA report. This provides consistency and transparency in the AER process for deriving an inflation forecast.

In the absence of an objective market-based approach, the AER considers that its methodology remains appropriate for the purposes of determining an inflation forecast in its determinations. The AER has updated the inflation forecast for the first two years of the regulatory control period using the latest published RBA inflation expectations as shown in table 11.3. The AER considers that, based on a simple average, an inflation forecast of 2.55 per cent per annum produces the best estimate for a 10-year period to be applied in the PTRM for this draft decision.

Table 11.3: AER's conclusion on inflation forecast (per cent)

	June 2010	June 2011	June 2012	June 2013	June 2014	June 2015	June 2016	June 2017	June 2018	June 2019	Average
Forecast inflation	3.00	2.50[a]	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.55

Source: RBA, *Statement on monetary policy*, 11 August 2008, p. 62.

(a) The RBA has not yet released a forecast for the year ending June 2011. This forecast will be available and adopted by the AER (including any updated forecasts) at the time of the final decision. The mid-point of its target inflation band has been assumed for the purposes of this draft decision.

The AER recognises that inflation forecasts will change in line with market sensitive data. Regulatory practice in Australia has been to update these parameter values at a time closer to the making of the final determination to take account of most recent information. Accordingly, the AER will update the inflation forecast to be used in the PTRM based on this methodology at the time of its final decision.

11.5 AER conclusions

The NER prescribes a number of the WACC parameter values to be adopted by the AER for the purposes of setting a rate of return for DNSPs. For the parameters where the values have not been prescribed—nominal risk-free rate and the debt risk premium—the NER sets out the methodology to be used by the AER for determining the values.

For this draft decision, the AER has determined a nominal vanilla WACC of 9.72 per cent for the NSW DNSPs, which is slightly less than that proposed by the DNSPs. This difference is due to a decline in the risk-free rate since the NSW DNSPs submitted their regulatory proposals. The impact of the decline in the risk-free rate was partly offset by a rise in the cost of debt.

Table 11.4 outlines the WACC parameter values for this draft decision. The AER will update the nominal risk-free rate and debt risk premium, based on the agreed averaging period, and the expected inflation rate at a time closer to its final determination.

Table 11.4: AER's conclusion on WACC parameters

Parameter	Country Energy	EnergyAustralia	Integral Energy
Risk–free rate (nominal)	5.34%	5.34%	5.34%
Risk–free rate (real)	2.72%	2.72%	2.72%
Expected inflation rate	2.55%	2.55%	2.55%
Debt risk premium	3.29%	3.29%	3.29%
Market risk premium	6.00%	6.00%	6.00%
Gearing	60%	60%	60%
Equity beta	1.00	1.00	1.00
Nominal pre–tax return on debt	8.63%	8.63%	8.63%
Nominal post–tax return on equity	11.34%	11.34%	11.34%
Nominal vanilla WACC	9.72%	9.72%	9.72%

11.6 AER draft decision

In accordance with clause 6.12.1(5) of the transitional chapter 6 rules the AER decides the rate of return to apply to Country Energy is 9.72 per cent.

In accordance with clause 6.12.1(5) of the transitional chapter 6 rules the AER decides the rate of return to apply to EnergyAustralia is 9.72 per cent.

In accordance with clause 6.12.1(5) of the transitional chapter 6 rules the AER decides the rate of return to apply to Integral Energy is 9.72 per cent.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the AER decides the other appropriate amounts, values or inputs to apply to Country Energy are as specified in table 11.4 of the draft decision.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the AER decides the other appropriate amounts, values or inputs to apply to EnergyAustralia are as specified in table 11.4 of the draft decision.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the AER decides the other appropriate amounts, values or inputs to apply to Integral Energy are as specified in table 11.4 of the draft decision.

12 Service target performance incentive scheme

12.1 Introduction

Following public consultation on a service performance incentive arrangement for the ACT and NSW DNSPs in late 2007, the AER decided not to introduce a service target performance incentive scheme (STPIS) for the next regulatory control period. This decision was taken as a result of concerns with the availability and quality of data for setting performance targets.[591] The AER's decision was to implement a data collection process in accordance with 6.6.2(h) of the transitional chapter 6 rules, with a view to applying a national STPIS to the NSW DNSPs for the regulatory control period commencing 1 July 2014.[592]

To facilitate the transition of the NSW DNSPs to a national STPIS from 1 July 2014, it was decided that data collection requirements for the next regulatory control period would be based on the AER's national STPIS for electricity DNSPs (the national distribution STPIS) and determined in consultation with the NSW DNSPs prior to commencement of the next regulatory control period.

The AER published its national distribution STPIS on 26 June 2008.[593] Following this, the AER advised the NSW DNSPs of how it proposed to conduct the data collection exercise based on the national distribution STPIS framework.[594]

12.2 Regulatory requirements

Clause 6.6.2(a) of the transitional chapter 6 rules provides that:

> The AER may develop and publish an incentive scheme or incentive schemes (service target performance incentive scheme) to provide incentives (which may include targets) for distribution network service providers to maintain and improve performance.

Although the AER has decided not to implement a STPIS under clause 6.6.2(a), it is required to collect service performance data during the next regulatory control period under clause 6.6.2(h) of the transitional chapter 6 rules, which states:

> The AER must monitor and collect information from any or all of the NSW and ACT DNSPs on matters relevant to be included in a service target performance incentive scheme for the purpose of developing, amending or applying a service target performance incentive scheme for the regulatory control period commencing on 1 July 2014.

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591 AER, *Final Decision, Service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations*, February 2008.
592 AER, *STPIS for ACT and NSW 2009 distribution determinations*, p. 15.
593 AER, *Electricity distribution network service providers service target performance incentive scheme*, 26 June 2008.
594 AER, letter to NSW DNSPs, 1 August 2008.

12.3 NSW DNSP proposals

Country Energy

Country Energy supported the AER's decision to implement information collection and monitoring based on the national distribution STPIS. It considered that this approach will continue to provide effective commercial incentives to maintain and improve service performance levels.[595]

EnergyAustralia

EnergyAustralia stated that the data collection exercise in the next regulatory control period should be based on a minimum set of measures, that may be reviewed at a later date.[596] It submitted that the most appropriate measures are those that:

- will be common to all NSW DNSPs
- are applied using consistent definitions
- that will demonstrate sufficient data integrity.[597]

EnergyAustralia submitted that the reliability measures contained within the current licence conditions satisfy these requirements, noting that these requirements promote greater granularity of reliability information at the feeder category and individual feeder levels.[598]

EnergyAustralia proposed that the AER draw on the annual Network Performance Report submitted by EnergyAustralia to the NSW Department of Water and Energy, as the source for the data collection process. It further submitted that the harmonisation of the data collection arrangements with jurisdictional reporting requirements is highly desirable.[599]

EnergyAustralia proposed that any adjustments arising from the application of the AER's national transmission STPIS currently applying to its transmission assets for the remainder of the current regulatory control period, should be reflected in the transmission portion of its maximum allowed revenue going forward.[600]

Integral Energy

Integral Energy submitted that the data collection exercise may be appropriate to define the data requirements and parameters to be measured in a national distribution STPIS,

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[595] Country Energy, *Regulatory proposal*, p. 173.
[596] EnergyAustralia, *Regulatory proposal*, p. 159.
[597] EnergyAustralia, *Regulatory proposal,* p. 159.
[598] EnergyAustralia, *Regulatory proposal*, p. 159.
[599] EnergyAustralia, *Regulatory proposal*, p. 160.
[600] EnergyAustralia, *Regulatory proposal*, p. 160. EnergyAustralia's transmission assets are subject to the AER's STPIS for transmission under chapter 6A of the NER until the end of the current regulatory control period, from which time these assets will be treated as part of the distribution network, consistent with the transitional chapter 6 rules. The implications of this are discussed at section 12.5.4 of this chapter. Section 4.4.2 of this draft decision sets out the approach to establishing maximum allowed revenues for EnergyAustralia's prescribed (transmission) standard control services, including the treatment of incentive amounts.

however it expressed caution against using actual results of the process for the purposes of establishing STPIS targets and incentives for the 2014–19 regulatory control period.[601] Integral Energy considers that, given no financial incentive will apply during the next regulatory control period, its commercial decisions will not be influenced as significantly, and resulting performance for the purposes of the data collection process may not be indicative of performance where financial incentives are applied.

12.4 Submissions

The Energy Market Reform Forum (EMRF) expressed concern that no service performance incentive targets have been set for the next regulatory control period for the ACT and NSW DNSPs. It submitted that this is not in the long-term interests of consumers.[602]

In September 2008, the NSW DNSPs wrote to the AER setting out their views on the AER's proposed data collection process. The key issues raised by the DNSPs in their proposals to the AER are set out below.

12.4.1 Aligning data reporting with existing obligations

Each of the NSW DNSPs submitted that the data collection requirements for the next regulatory control period should be aligned with the methods and definitions prescribed under existing service performance reporting licence requirements imposed by the NSW Department of Water and Energy.[603] EnergyAustralia submitted that to do otherwise would impose additional costs of reporting and that maintaining two sets of conflicting performance data on similar reliability measures is likely to cause confusion and inaccurate reporting of reliability if such information was to be used by third parties.[604] The NSW DNSPs identified the following key points of difference between the national distribution STPIS, and the existing NSW licence condition service performance reporting framework:

- definitions of a CBD feeder which would give rise to different categorisations of some feeders on EnergyAustralia's and Integral Energy's networks
- methods for determining major event day threshold
- timing for refreshing the major event day threshold
- measurement of the 'telephone answering' parameter
- differences in specific exclusion provisions between the two frameworks.

601 Integral Energy, *Regulatory proposal*, p. 194.
602 EMRF submission on regulatory proposals, August 2008, p. 33.
603 See, *Design, reliability and performance licence conditions imposed on distribution network service providers by the Minister for Energy and Utilities*, 1 December 2007.
604 EnergyAustralia, letter to AER, 26 September 2008.

12.4.2 Momentary average interruption frequency index (MAIFI)

Under the national distribution STPIS, reporting data against the momentary average interruption frequency index (MAIFI) parameter is not mandatory. This approach reflects that not all DNSPs will be capable of reporting this data immediately.

Country Energy submitted that it is unlikely to be able to provide MAIFI data for the 2009–10 regulatory year. It submitted that it is currently working towards collecting MAIFI data, but only for those parts of the network which have existing remote communication capability, and those circuit breakers and reclosers that are within zone substations with existing SCADA connections. It stated that to immediately equip all other reclosers would be prohibitively costly, however, this will occur over a longer time frame.[605]

EnergyAustralia submitted that it would have difficulty in reporting MAIFI data initially.[606] It proposed to exclude MAIFI from the data collection exercise for the next regulatory control period.

Integral Energy proposed to exclude MAIFI from its reporting during the next regulatory control period. It said that it has a program in place to install the necessary equipment to the reclosers to enable recording of MAIFI, however, this is expected to take until at least the end of the next regulatory control period.[607]

Country Energy and EnergyAustralia also submitted that the national distribution STPIS definition for MAIFI should be amended to capture only the initial momentary outage, not subsequent attempts by reclosers to clear a fault, as the STPIS currently requires.

12.4.3 Use of data collected to set future performance targets

Country Energy submitted that the AER should not use the information collected to determine performance targets for the 2014–19 regulatory control period where jurisdictional targets already exist.[608]

Integral Energy submitted that it would caution against using the reported data to set future performance targets until such time as Integral Energy is confident that its new outage management system data accurately reflects the actual customer experience. It submitted the initial impact of the new system on reported performance outcomes is unknown.[609]

12.5 Issues and AER considerations

12.5.1 Service performance incentive targets during the next regulatory period

The AER’s decision not to implement a STPIS for the NSW DNSPs was based on the following conclusions:

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605 Letter from Country Energy to AER, 26 September 2008.
606 Letter from EnergyAustralia to AER, 26 September 2008.
607 Letter from Integral Energy to AER, 25 September 2008, p. 2.
608 Letter from Country Energy to AER, 26 September 2008.
609 Letter from Integral Energy to AER, 25 September 2008, p. 2.

- existing performance data in NSW was not considered robust enough for use in setting targets linked to financial penalties in the immediate future
- the timeframes mandated by the transitional chapter 6 rules meant that there was limited opportunity to consult and develop a robust STPIS to apply for the next regulatory control period
- existing mandated licence obligations were likely to drive improvements to reliability during the next regulatory control period and the consequences of this for setting performance targets could not be adequately assessed.

The NSW DNSPs have an obligation to improve network reliability and security to ensure compliance with the mandated licence conditions targets. This is evidenced by the forecast capex and opex allowances proposed by the NSW DNSPs to specifically target reliability improvements during the next regulatory control period. The AER considers that if the planned projects and programs targeted at reliability improvement are implemented as proposed, network reliability performance in NSW is likely to improve rather than diminish during the next regulatory control period.

From 1 July 2014, the NSW DNSPs will be subject to the provisions of the general chapter 6 rules, rather than the transitional provisions which provide discretion in the application of a STPIS. The AER expects that financial rewards and penalties will be linked to revenues when the national distribution STPIS is applied to the NSW DNSPs during the 2014–19 regulatory control period.

12.5.2 Aligning data reporting with existing obligations

The AER considered the NSW DNSPs' proposal to base the data collection process on the performance reporting obligations imposed under the existing NSW licence conditions.

While the national distribution STPIS does allow for some flexibility in its application to recognise differences between DNSPs and jurisdictions, this flexibility does not extend to adopting alternative parameter definitions and methods, as proposed by the NSW DNSPs. To accommodate the proposed alignment with the existing licence conditions, the AER would need to amend the national distribution STPIS. It is not possible to amend the national distribution STPIS as part of the distribution determination process. In the event that the national distribution STPIS is amended following consideration of a formal proposal to the AER to amend the scheme in accordance with section 1.8 of the national distribution STPIS, then any change to the reporting requirements of the NSW DNSPs would be determined at that time.

The transitional chapter 6 rules envisage that the STPIS is to operate concurrently with any average or minimum service standards and GSL scheme that applies to a DNSP under jurisdictional electricity legislation.[610] The national distribution STPIS was not developed with the intent of mirroring existing obligations. Rather, it was developed to establish a nationally consistent incentive framework for DNSP service performance.

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[610] Transitional chapter 6 rules; Note to clause 6.6.2(b)(2).

The AER acknowledges that, by not amending the national distribution STPIS to align with the NSW licence requirements, the NSW DNSPs will be required to report two sets of reliability data. However, the AER does not accept EnergyAustralia's submission that maintaining two divergent sets of performance data will necessarily cause confusion. The AER expects the NSW DNSPs to have appropriate processes in place to ensure that a clear distinction is made between reliability data reported to the AER under the national distribution STPIS, and data reported to the NSW Department of Water and Energy under the distribution licence conditions.

In summary, the AER does not consider it appropriate to amend the national distribution STPIS to align with the definitions and requirements of the existing NSW licence conditions. The AER considers it important to maintain consistent definitions and methodologies for the scheme to be ultimately applied in a nationally consistent manner, and considers this will reduce compliance and administration costs over time. The performance data provided to the AER by the NSW DNSPs during the next regulatory control period is to be recorded and reported in accordance with the specific definitions and requirements of the national distribution STPIS, as set out at table 12.1 of this draft decision. Where the NSW DNSPs have not yet developed the capacity to comply with these definitions or methods, the AER expects the necessary systems and processes to be established as soon as possible during the next regulatory control period, and at the latest, by December 2009.

Materiality of compliance costs

The AER acknowledges that maintaining and reporting two sets of data may increase administrative costs for the NSW DNSPs, however, based on the information before it, the AER does not believe those costs to be significant.

The requirements of the national distribution STPIS are closely based on the requirements established by the Steering Committee on National Regulatory Reporting Requirements (SCNRRR).[611] The AER understands that the NSW DNSPs have previously reported performance in accordance with these definitions and methods and therefore considers they should not face significant compliance costs in reporting data against these definitions.

12.5.3 Momentary average interruption frequency index (MAIFI)

Reporting

The AER notes that the NSW DNSPs have not previously been required to report MAIFI data and, as such, may need to undertake additional investments and preparations before establishing this capability. Where a DNSP will not have capabilities to report MAIFI at the commencement of the next regulatory control period, the AER expects the DNSPs to establish that capacity as soon as reasonably possible.

Definition

EnergyAustralia and Country Energy commented on the appropriateness of the MAIFI parameter used in the national distribution STPIS. They submitted that a more appropriate

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611 Utility Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses*, March 2002.

measure of MAIFI would capture only the first momentary interruption, and not subsequent attempts by automatic reclosers to clear a fault.

The AER's national distribution STPIS has adopted the definition of MAIFI established by SCNRRR. The national distribution STPIS prescribes that:

> In calculating MAIFI, each operation of an automatic reclose device is counted as a separate interruption. Sustained interruptions which occur when a recloser locks out after several attempts to reclose should be deleted from MAIFI calculations.[612]

The AER has developed and published its national distribution STPIS following stakeholder consultation. The AER did not receive any comments on its proposed definition for the MAIFI parameter during that consultation.

The AER does not accept the proposed alternative definition for MAIFI. The AER considers that the national distribution STPIS definition should apply when the NSW DNSPs develop the capacity to report MAIFI data. Any change to the MAIFI definition needs to be considered in the context of possible changes to the national distribution STPIS.[613]

12.5.4 EnergyAustralia prescribed (transmission) standard control services

Clause 6.1.6 of the transitional chapter 6 rules deems EnergyAustralia's transmission support network assets to be part of its distribution network for the purposes of chapter 6 and chapter 6A. However, in determining service standards to apply to these transmission support network assets during the next regulatory control period, clause 6.6.2(i) of the transitional chapter 6 rules provides that the AER may adopt elements of the AER's incentive scheme developed for transmission assets under chapter 6A of the NER.

In February 2008, the AER decided that it will not apply elements of the chapter 6A service standards incentive regime to EnergyAustralia's transmission support network during the next regulatory control period.[614] The AER will consider these assets to be part of EnergyAustralia's distribution network for the purposes of the data collection process during the next regulatory control period. When reporting data in accordance with the requirements of the data collection process set out at section 12.6 of this chapter, EnergyAustralia should include the performance of both its transmission and distribution network assets in the reported reliability data.

Any remaining adjustments arising from the application of the national chapter 6A transmission STPIS currently applying to EnergyAustralia's transmission assets for the remainder of the current regulatory control period, will be reflected in the transmission portion of EnergyAustralia's maximum allowed revenue during the next regulatory control period. Specifically, any incentive amounts incurred in the final calendar year of the current regulatory control period will have a revenue impact during the first year of the next regulatory control period.

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612 AER, *National distribution STPIS*, p. 22.
613 Should the national distribution STPIS be amended during the next regulatory control period, the AER will advise the NSW DNSPs of any subsequent changes to the data collection requirements.
614 AER, *STPIS for ACT and NSW 2009 distribution determinations*, p. 11.

12.5.5 Use of data to set future performance targets

The AER notes Integral Energy's and Country Energy's concerns with using information collected under the data collection process in setting future performance targets. The AER's February 2008 decision on STPIS arrangements for the ACT and NSW for the next regulatory control period concluded that it should begin establishing a historical data series for potential use in setting targets under the national distribution STPIS. The national distribution STPIS will be applied to the ACT and NSW DNSPs for the regulatory control period commencing 1 July 2014.

The national distribution STPIS, published on 26 June 2008, envisages that performance targets will based on 5 year historical average performance.[615]

The AER notes that the application of the national distribution STPIS to the ACT and NSW DNSPs from 1 July 2014 (including the derivation of performance targets to apply) will be the subject of consultation during the framework and approach process prior to commencement of the 2014–19 regulatory control period. The derivation of performance targets to apply from 1 July 2014 therefore is not addressed in this draft distribution determination.

12.6 AER conclusion

In accordance with clause 6.6.2(h) of the transitional chapter 6 rules, the AER will collect and monitor service performance data during the next regulatory control period. Revenue will not be placed at risk under the data collection process during this period.

In consultation with the NSW DNSPs, the AER has developed service performance data reporting requirements for the next regulatory control period. As foreshadowed in the final decision on STPIS arrangements for the ACT and NSW distribution determinations, the data reporting requirements have been aligned with the requirements of the national distribution STPIS. Collection of data consistent with the national distribution STPIS is important to ensure that a reliable data series is available for potential use in setting performance targets once the national distribution STPIS is applied from 1 July 2014.

The AER acknowledges that the NSW DNSPs may need to adjust existing systems and, in some cases, implement additional systems and processes, to achieve full compliance with the national distribution STPIS by 1 July 2014. However, to ensure that the data collection process is effective in establishing a useable data set for future target setting, the AER expects the NSW DNSPs to implement measures to achieve full compliance with the national distribution STPIS as soon as practical, in order to ensure that data from 2009−10 is assessable by December 2010.

In implementing the data reporting requirements, the AER expects to accumulate a reliable data series to allow the application of the national distribution STPIS to the NSW DNSPs from 1 July 2014. The application of the national STPIS for the 2014–19 regulatory control period to the NSW DNSPs will be the subject of consultation under the framework and approach process, prior to the 2014−19 distribution determination.

[615] AER, *National distribution STPIS*, p. 9.

Table 12.1 sets out the application of the national STPIS framework for service performance data collection under clause 6.6.2(h) of the transitional chapter 6 rules during the next regulatory control period for the NSW DNSPs. These arrangements should be read in conjunction with the national distribution STPIS.

Table 12.1 Service performance data collection arrangements for NSW DNSPs: 2009–14

Element	Relevant provision in national distribution STPIS	Requirements for the 2009–14 regulatory control period
Timing of performance measure	2.4	The NSW DNSPs must measure performance in accordance with the data collection process for each financial year from 1 July until 30 June inclusive, starting from 1 July 2009
Revenue at risk	2.5	No revenue will be placed at risk under the data collection process during the 1 July 2009 to 30 June 2014 regulatory control period. Performance outcomes reported during the 2009–14 regulatory control period may be used in determining performance targets for the 2014–19 regulatory control period.
Reliability of supply component	3.1	Section 3.1 of the national distribution STPIS must be observed during the 2009–14 data collection process, with the exception of clause 3.1(e). For the 2009–14 data collection process, the NSW DNSPs are to report annual performance against the following parameters, consistent with section 3.1 of the national distribution STPIS: • Unplanned SAIDI • Unplanned SAIFI • Capability to record and report MAIFI, as defined at appendix A of the national distribution STPIS is to be established as soon as reasonably possible. The NSW DNSPs are to divide their electricity network into segments by feeder type as specified in clause 3.1(c) of the national distribution STPIS for the purposes of reporting this information.
Exclusions – reliability of supply component	3.3	Events to be excluded for the purposes of reporting data under the 2009–14 data collection process are to be consistent with those set out at section 3.3 of the national distribution STPIS.
Customer service component	5.1	The NSW DNSPs are to report performance against the customer service parameter ‘telephone answering’ and may propose additional parameters subject to clauses 5.1(c) – 5.1(e) of the national distribution STPIS. No revenue will be placed at risk under section 5.2 of the national distribution STPIS, for the 2009–14 data collection process.

Exclusions – customer service component	5.4	Section 5.4 of the national distribution STPIS must be observed in determining events to be excluded for the purposes of reporting performance under the 2009–14 data collection process.
Guaranteed service level component	6	A GSL scheme currently applies to the NSW DNSPs under existing jurisdictional legislation. Consistent with clause 6.1(b) of the national STPIS, should these obligations be removed during the next regulatory control period, the AER may require reporting of performance under clauses 6.2 − 6.4 of the national distribution STPIS, with the exception of clauses 6.3.1, 6.3.2 and 6.3.3.
Information and reporting requirements	7	Section 7 of the national distribution STPIS must be observed during the 2009–14 data collection process, with the exception of clause 7.2(b)(3). The AER will request information for the data collection process through an annual regulatory reporting process. The AER expects to initiate the first request for such data following the conclusion of the first year of the next regulatory control period. This information request will relate to performance during the period 1 July 2009 to 30 June 2010.
Format of data	n/a	The AER will determine appropriate reporting formats in consultation with the NSW DNSPs, prior to the first request for information.

12.7 AER draft decision

In accordance with clause 6.3.2(a)(3) of the transitional chapter 6 rules, the AER decides that the application of the service target performance incentive scheme to apply to the NSW DNSPs is as specified in section 12.6 of the draft decision.

13 Efficiency benefit sharing scheme

13.1 Introduction

This chapter sets out how the AER intends to apply its efficiency benefit sharing scheme (EBSS) to the NSW DNSPs. An EBSS shares between DNSPs and distribution network users the efficiency gains or losses derived from the difference between a DNSP's actual opex and the forecast opex allowance for a regulatory control period.

The AER has published an EBSS, under clause 6.5.8(a) of the transitional chapter 6 rules, which establishes a scheme that will apply to the NSW DNSPs from 1 July 2009.[616] The scheme will not have a direct financial impact on the NSW DNSPs until the 2014–19 regulatory control period, when the DNSPs will receive carryover benefits/penalties for efficiency gains/losses made during the next regulatory control period.

13.2 Regulatory requirements

Clause 6.5.8(a) of the transitional chapter 6 rules provides that the AER may develop and publish an EBSS. Under clause 6.12.1(9) of the transitional chapter 6 rules, the AER must specify how this EBSS will apply to the NSW DNSPs as part of its distribution determinations.

First year formula

The EBSS guideline states that the AER will calculate an efficiency gain or loss in the first year of the regulatory control period using the following formula:

$$E_1 = F_1 - A_1$$

where:

E_1 = the efficiency gain/loss in year 1

A_1 = actual opex incurred by the DNSP for year 1 of the regulatory control period

F_1 = forecast opex accepted or substituted by the AER in the distribution determination for year 1 of the regulatory control period.

Subsequent years' formula

Gains or losses that arise in the second and subsequent years of the regulatory control period will be calculated as:

$$E_t = (F_t - A_t) - (F_{t-1} - A_{t-1})$$

where:

E_t = the efficiency gain/loss in year t

616 AER, *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008.

A_t, A_{t-1} = the actual, or adjusted actual, opex incurred in years t and t–1 respectively

F_t, F_{t-1} = the forecast, or adjusted forecast, opex accepted or substituted by the AER for years t and t–1 respectively.

Final year formula

As the distribution determination for the 2014–19 regulatory control period will be made prior to the completion of the next regulatory control period, the AER will estimate the actual opex required to calculate gains or losses for the final year of the next regulatory control period as follows:

$$A_5 = F_5 - (F_4 - A_4)$$

Where differences arise between this estimate and the actual expenditure amount of the final year, the efficiency gain or loss in the first year of the 2014–19 regulatory control period (E_6) will be adjusted as follows:

$$E_6 = (F_6 - A_6) - (F_5 - A_5) + (F_4 - A_4)$$

Other provisions

The EBSS also makes provision for:

- adjustments to forecast opex allowances for the purpose of calculating carryover amounts to account for variations between forecast and outturn demand growth
- DNSPs to propose cost categories to be excluded from the operation of the EBSS
- the review or amendment of the EBSS with the agreement of each affected DNSP under clause 6.5.8(d) of the transitional chapter 6 rules.

13.3 NSW DNSP proposals

None of the NSW DNSPs proposed an adjustment mechanism for actual demand growth at the end of the next regulatory control period when calculating carryover amounts.

The EBSS allows DNSPs to propose a range of additional cost categories to be excluded from the operation of the EBSS. The scheme requires that these cost categories must be proposed by a DNSP in their regulatory proposal for the next regulatory control period. Integral Energy proposed that transmission use of system (TUOS) charges be excluded from the EBSS.[617] Neither Country Energy nor EnergyAustralia proposed any cost categories be excluded from the operation of the EBSS.

13.4 Consultant review

As part of its review of the NSW DNSP's regulatory proposals Wilson Cook assessed the reasonableness of the opex cost categories proposed by the DNSPs to be uncontrollable for the purposes of the EBSS.

[617] Integral Energy, *Regulatory proposal*, pp. 192–193.

Wilson Cook suggested that proposals for exclusions from the EBSS:

> … ought to meet a high threshold in the sense of being uncontrollable, as the pressure on the DNSPs to minimise costs efficiently in any reasonable changing circumstance ought not to be diluted.[618]

Wilson Cook considered Integral Energy's proposed cost categories solely from the standpoint of whether the costs were uncontrollable. On that basis, Wilson Cook considered that TUOS costs and any approved cost pass through events should be excluded as it considered those cost categories to be clearly outside the control of the DNSP.[619]

13.5 Issues and AER considerations

13.5.1 Demand growth adjustment

In developing the EBSS the AER recognised that a DNSP's opex may be affected by the level of demand growth experienced in the network.[620] The EBSS provides that forecast opex is to be adjusted for variances between actual and forecast demand growth. This is intended to prevent DNSPs being penalised/rewarded for changes in opex that are directly attributable to demand growth which is beyond the control of the DNSP. However, as the AER may make a decision about how to apply the EBSS to a particular DNSP, it may decide not to make such an adjustment.[621]

NSW DNSP proposals

None of the NSW DNSPs discussed how they considered forecasts should be adjusted for actual demand growth at the end of the next regulatory control period when calculating carryover amounts. However, EnergyAustralia proposed:[622]

> … to engage with the AER to develop a process by which changes of scale and scope can be accounted for the calculation of the EBSS incentive amounts.

Similarly Integral Energy stated that it:[623]

> … looks forward to working with the AER to better define how variances in outturn demand and cost changes will be addressed prior to the introduction of the EBSS at the start of the 2009 regulatory control period.

AER considerations

The AER does not consider a demand growth adjustment is necessary for the EBSS to provide DNSPs with a continuous incentive to pursue efficiency gains. The demand growth adjustment was incorporated into the EBSS to prevent DNSPs from being penalised or rewarded by the EBSS for changes in demand growth over which the DNSP has no control. The risk to DNSPs of being rewarded or penalised by the EBSS for changes in demand growth is a symmetrical one. The AER considers it reasonable for the

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618 Wilson Cook, volume 1, p. 12.
619 Wilson Cook, volume 3, p. 45.
620 AER, *EBSS for ACT and NSW,* p. 5.
621 Transitional chapter 6 rules, clause 6.12.1(9).
622 EnergyAustralia, *Regulatory proposal*, p. 158.
623 Integral Energy, *Regulatory proposal*, p. 192.

EBSS to not be adjusted for changes in demand growth if a DNSP does not regard this necessary.

Given that the NSW DNSPs have not proposed an adjustment method, the AER considers that the EBSS should not be adjusted for the consequences of changes in demand growth for the next regulatory control period.

13.5.2 Excluded cost categories

By default the EBSS excludes the costs of pass through events from the calculation of carryover amounts. In addition, the EBSS allows DNSPs to propose a range of additional cost categories to be excluded from the operation of the EBSS. The scheme requires that these cost categories must be proposed by a DNSP in their regulatory proposal for the next regulatory control period.[624]

NSW DNSP proposals

Neither Country Energy nor EnergyAustralia proposed any cost categories for exclusion from the operation of the EBSS. Country Energy stated that it supported the nominated default cost categories for exclusion from the scheme but did not propose any further cost categories.

Integral Energy proposed that TUOS charges be excluded from the operation of the EBSS. For the EBSS to operate the AER requires that opex forecasts be disaggregated for those cost categories proposed to be excluded. Integral Energy, however, noted that forecast information for TUOS is only available one year in advance and is unavailable at this time.[625]

AER considerations

There are two factors that should be considered when assessing whether an opex category should be excluded from the EBSS. The first factor is whether or not the opex is controllable. The AER does not consider it appropriate for DNSPs to receive benefits or penalties through the EBSS for variances in its opex for cost categories over which it has no control.

The second factor is how actual expenditure for that cost category is used in setting opex forecasts for the following regulatory control period. The EBSS assumes that actual opex is used as a basis for setting future opex allowances. If this is not the case, for instance if opex forecasts for a given cost category were based on an external benchmark, the EBSS would not provide a continuous incentive to reduce opex.

Applying these factors the AER considers it appropriate to exclude from the operation of the EBSS for the NSW DNSPs for the next regulatory control period the following opex cost categories:

- debt raising costs
- self insurance costs

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[624] AER, *EBSS for ACT and NSW,* p. 6.
[625] Integral Energy, *Regulatory proposal*, pp. 192–193.

- insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- non–network alternatives.

These are in addition to the costs of pass through events which are directly excluded by the EBSS.

The AER considers it appropriate that debt raising costs be excluded from the operation of the EBSS on the basis that forecast costs are based on a benchmark efficient firm rather than the historical costs of the DNSP. Similarly, self insurance and insurance cost forecasts are based on independent expert analysis rather than historical costs. Consequently, the AER considers it reasonable that they also be excluded from the operation of the EBSS.

The AER notes that many DNSP employees are members of defined benefit superannuation schemes. Consequently, a DNSP's superannuation liabilities relating to these employees are impacted, among other things, by the number of these employees that retire in a given year and the performance of the superannuation fund. Given that both of these factors are beyond the control of the DNSP, the AER considers it reasonable that those superannuation costs be excluded from the operation of the EBSS.

Regarding TUOS charges, the AER notes that DNSPs recover these charges separately through transmission cost recovery tariffs. Consequently, TUOS charges are not included in a DNSP's forecast opex. It is important that the forecast and actual opex values used to calculate EBSS carryover amounts include the same cost categories. TUOS charges should therefore not be included in a DNSP's actual opex when calculating EBSS carryover amounts.

The AER also considers that to meet the requirements of the transitional chapter 6 rules, non–network alternatives should be excluded from the operation of the EBSS. This ensures that the EBSS does not impact the incentives for DNSPs to implement non–network alternatives.

13.5.3 Other issues

NSW DNSP proposals

Country Energy stated that it:[626]

> … believes the framework and methodology in applying EBSS still require further development and welcomes the opportunity to work with the AER on the operation of EBSS during the course of the review process.

EnergyAustralia argued that it is unclear 'how the balance and magnitude of sharing will be affected by the setting of efficient operating expenditure allowances in future regulatory periods'. EnergyAustralia provided modelling that it contends 'shows anomalous outcomes under certain conditions'. Consequently, EnergyAustralia proposed

[626] Country Energy, *Regulatory proposal*, p. 173.

that the EBSS should allow carryover amounts to be set to zero by mutual agreement between EnergyAustralia and the AER.[627]

Similarly Integral Energy proposed that:[628]

> … the AER introduce a mechanism in its final determination to allow, for any negative carry forward amounts to not be applied or to be offset against any positive carry forward amounts.

AER considerations

The AER notes Country Energy's view that the framework and methodology in applying the EBSS requires further development. The AER welcomes any suggestions for improvement to the EBSS and will give due consideration to any such suggestions provided to it.

The AER has analysed the modelling of the EBSS provided to it by EnergyAustralia and does not consider that it shows 'anomalous outcomes'. The AER's analysis of this modelling is provided in appendix S. Based on that analysis, the AER does not think it appropriate to allow carryover amounts to be set to zero by mutual agreement of EnergyAustralia and the AER. The AER considers that doing so would increase uncertainty and weaken the incentives provided by the EBSS.

Similarly, the AER does not consider it appropriate to not apply negative carryovers or to offset them against any future positive carryovers as proposed by Integral Energy. The AER considered this during the development of the EBSS and, in the absence of any compelling new argument or evidence, does not consider it appropriate to alter the EBSS.[629]

13.6 AER conclusions

The AER will apply the EBSS released in February 2008 to the NSW DNSPs for the next regulatory control period. Given that none of the DNSPs proposed an ex post demand growth adjustment method, the AER will not adjust the EBSS for the consequences of changes in demand growth for the NSW DNSPs for the next regulatory control period.

The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- non–network alternatives.

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[627] EnergyAustralia, *Regulatory proposal*, p. 158.
[628] Integral Energy, regulatory proposal, p. 193.
[629] AER, *EBSS for ACT and NSW,* pp. 19–21.

These are in addition to the costs of pass through events which are directly excluded by the EBSS.

The forecast controllable opex for each of the NSW DNSPs is outlined in tables 13.1 to 13.3 and will be used to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS.[630]

Table 13.1: Country Energy's forecast controllable opex for EBSS purposes ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14
Total forecast opex	359.9	368.2	378.7	429.9	438.5
Adjustment for debt raising costs	–2.0	–2.3	–2.5	–2.8	–3.0
Adjustment for self insurance costs	–3.0	–3.0	–3.0	–3.0	–3.0
Adjustment for insurance costs	–5.6	–5.7	–5.8	–6.0	–6.2
Adjustment for superannuation costs[a]	–8.2	–8.2	–8.5	–8.8	–9.2
Adjustment for non–network alternatives	–	–	–	–	–
Forecast opex for EBSS purposes	341.1	349.1	358.9	409.3	417.1

(a) The superannuation costs relating to defined benefit and retirement schemes are indicative only and will be confirmed at the time of the AER's final decision and determination.

Table 13.2: EnergyAustralia's forecast controllable opex for EBSS purposes ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14
Total forecast opex	498.1	511.4	527.6	544.9	555.8
Adjustment for debt raising costs	–3.8	–4.5	–5.1	–5.8	–6.4
Adjustment for self insurance costs	–4.1	–4.1	–4.1	–4.1	–4.1
Adjustment for insurance costs	–4.6	–4.6	–4.6	–4.6	–4.6
Adjustment for superannuation costs	–	–	–	–	–
Adjustment for non–network alternatives	–4.0	–4.1	–4.2	–4.2	–4.3
Forecast opex for EBSS purposes	481.6	494.1	509.7	526.2	536.4

630 AER, *EBSS for ACT and NSW,* pp. 5–6, for an outline of the adjustments required by the EBSS.

Table 13.3: Integral Energy's forecast controllable opex for EBSS purposes ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14
Total forecast opex	285.0	287.7	291.9	296.3	299.4
Adjustment for debt raising costs	–1.7	–1.9	–2.1	–2.3	–2.5
Adjustment for self insurance costs	–1.9	–1.9	–1.9	–1.9	–1.9
Adjustment for insurance costs	–6.2	–6.2	–6.2	–6.2	–6.2
Adjustment for superannuation costs[a]	12.5	13.1	13.7	14.4	15.1
Adjustment for non–network alternatives	–1.5	–1.6	–1.6	–1.6	–1.6
Forecast opex for EBSS purposes	286.1	289.3	293.8	298.6	302.2

(a) The superannuation adjustments relate to Integral Energy's defined benefit scheme costs. These forecasts were based on the defined benefit fund being in surplus and are recorded as a credit in the forecast opex.

13.7 AER draft decision

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the AER decides the efficiency benefit sharing scheme to apply to Country Energy is as defined in the AER's *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, published in February 2008. The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- non–network alternatives.

These are in addition to the costs of pass through events which are excluded by the EBSS.

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the AER decides the efficiency benefit sharing scheme to apply to EnergyAustralia is as defined in the AER's *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, published in February 2008. The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- non–network alternatives.

These are in addition to the costs of pass through events which are excluded by the EBSS.

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the AER decides the efficiency benefit sharing scheme to apply to Integral Energy is as defined in the AER's *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, published in February 2008. The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- non–network alternatives.

These are in addition to the costs of pass through events which are excluded by the EBSS.

In accordance with clause 6.3.2(a)(3) of the transitional chapter 6 rules, the AER decides that the application of the efficiency benefit sharing scheme to apply to the NSW DNSPs is as specified in section 13.6 of the draft decision.

14 Demand management incentives

14.1 Introduction

This chapter sets out the AER's demand management incentive scheme (DMIS) to apply to the NSW DNSPs for the next regulatory control period. The DMIS to apply to the NSW DNSPs has two components: an innovation allowance scheme and the existing D–factor scheme developed and applied by IPART in its 2004 determination.

In February 2008 the AER released a demand management innovation allowance scheme (DMIA) to apply to the NSW DNSPs in the next regulatory control period.[631] The DMIA will provide incentives for the NSW DNSPs to pursue innovative, broad–based, non–network solutions to growing demand and constraints on their networks.

This chapter sets out the AER's considerations and conclusions on how the DMIA and D–factor scheme should apply to the NSW DNSPs over the next regulatory control period. It also provides a brief description of demand management projects carried out during the current regulatory control period, and demand management projects proposed by the DNSPs for the next regulatory control period.

14.2 Regulatory requirements

Clause 6.6.3 of the transitional chapter 6 rules provides that

> the AER may develop and publish a DMIS to provide incentives for DNSPs to implement efficient non–network alternatives or to manage the expected demand for standard control services in some other way.

On 29 February 2008, the AER published two DMIS to apply to the NSW DNSPs over the next regulatory control period; a DMIA (the original DMIA) and a D–factor scheme.[632] The AER can determine how the DMIS will apply to a DNSP as part of its distribution determination under clause 6.12.1(9) of the transitional chapter 6 rules.

14.2.1 D–factor

The AER will apply the D–factor scheme to the NSW DNSPs for the next regulatory control period, as it was applied by IPART in the current regulatory control period. The AER will apply the scheme as outlined in IPART's *Guidelines on the Application of the D–factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination* (IPART's D–factor guidelines).

The AER will honour the final two years of the current regulatory control period expenditure under the D–factor scheme (regulatory years 2007–08 and 2008–09), in the first two years of the next regulatory control period (years 2009–10 and 2010–11), as set out in the AER final decision on DMIS for the ACT and NSW DNSPs.[633]

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631 AER, *Final Decision: Demand management incentives schemes for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008.
632 AER, *Final Decision*, *DMIS*, p. 29.
633 AER, *Final Decision, DMIS.*

14.2.2 Demand Management Innovation Allowance

Clause 6.6.3(c) of the transitional chapter 6 rules states the AER may, from time to time, and with the agreement of each affected DNSP, amend or replace any published DMIS. As part of its draft determination, and dependent upon the agreement of each affected DNSP, the AER proposes to amend the original DMIA scheme (published on 29 February 2008), by replacing it with the DMIA set out in the AER's *Demand management incentive scheme for the ACT and NSW distribution determinations*, published in November 2008 (the replacement DMIA).[634]

The replacement DMIA takes account of the AER's current considerations in developing a DMIS to apply to DNSPs in Queensland and South Australia. It also addresses a number of issues raised in the NSW DNSPs' regulatory proposals and stakeholders' submissions on these proposals.

The replacement DMIA provides NSW DNSPs with the following allowances for demand management projects over the next regulatory control period:

- EnergyAustralia–$1 million per annum
- Country Energy–$0.6 million per annum
- Integral Energy–$0.6 million per annum.

The allowances are identical to those provided to the DNSPs in the original DMIA.

The replacement DMIA varies the original DMIA by modifying the way the allowance is provided and the criteria for assessment. The replacement DMIA provides an allowance for demand management projects within the DNSPs' opex forecasts for the next regulatory control period. It also allows for a one off adjustment at the end of the next regulatory control period for any amount of the allowance unspent or unapproved over the regulatory control period, and the time value of money lost or accrued as a result of the expenditure profile selected by the DNSP.[635]

To be eligible for the allowance under the replacement DMIA, demand management programs must meet the criteria established in the DMIA.[636] By setting criteria, the replacement DMIA provides certainty as to which demand management programs are eligible for the allowance, and negates the need for the case–by–case ex ante approval process as provided for in the original DMIA.

For DNSPs subject to a form of control where revenue is dependent on the quantity of electricity sold (including a weighted average price cap), the replacement DMIA allows for the recovery of forgone revenues resulting from a reduction in the quantity of electricity sold due to approved demand management projects carried out under the scheme, independently of the allowance provided.[637] Recovery of forgone revenue under the replacement DMIA does not have a specified cap. However, the actual amount that

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634 In this case, each affected DNSP includes Country Energy, EnergyAustralia and Integral Energy.

635 AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme,* November 2008, pp. 6–7.

636 AER, *DMIS- DMIA*, pp. 4–5.

637 AER, *DMIS - DMIA*, pp. 7–11.

can be recovered is limited to approved revenue forgone resulting from a successful project carried out under the DMIA.

14.3 NSW DNSP proposals

14.3.1 Country Energy

14.3.1.1 Application of schemes

D–factor

Country Energy stated it supports the AER's decision to continue the D–factor scheme in NSW. However it considered the D–factor is not an effective means of cost recovery for large scale pilot programs that incorporate smart meters.[638] Country Energy proposed that the potential deployment of 'intelligent network infrastructure' be nominated as a pass–through event in the AER's distribution determination for the next regulatory control period, to overcome the limitations of the D–factor in providing cost recovery for large scale smart meter pilots.[639] The AER's consideration of Country Energy's nominated pass through events is provided in chapter 15.

Country Energy stated that to date it has made only modest claims under the D–factor due to the limited compatibility between currently available technologies for non–network alternatives, and the specific nature of emerging network constraints in the Country Energy service area.[640]

Country Energy also submitted that to date, available demand management options have been generally unable to provide a reliable, economic alternative to capital investment to addressing reliability issues.[641] It stated there are comparatively few large customers or embedded generators in Country Energy's network, which limits opportunities for large scale load reductions in locations subject to network constraints.

Demand management innovation allowance

Country Energy stated its support for the implementation of the AER's DMIA for the next regulatory control period.[642] However, it submitted the $0.6 million per annum allowance for Country Energy proposed within the AER's DMIA is unlikely to cover the cost of undertaking 'intelligent network pilots and trials,' and thus it proposed the DMIA be increased.[643]

[638] Country Energy, *Regulatory proposal*, pp. 169–172.
[639] Country Energy, *Regulatory proposal*, p. 169.
[640] Country Energy, *Regulatory proposal*, p. 172.
[641] Country Energy, *Regulatory proposal*, p. 172.
[642] Country Energy, *Regulatory proposal*, p. 172.
[643] Country Energy, *Regulatory proposal*, p. 169.

14.3.1.2 Demand management initiatives

Current regulatory control period

Country Energy listed the following demand management projects, investigations and trials it has carried out over the current regulatory control period:[644]

- power factor correction
- voltage conversion
- load control system upgrades
- fuel substitution program
- conductor upgrade programs
- 'green towns' project
- energy efficient street lighting
- negotiated outcomes with customers
- smart meter field trials
- emerging technologies trials (such as solar or carbon block oil thermal for peak lopping)
- gas generation trials
- embedded generation trials
- peak demand shifting trials.

Next regulatory control period

Country Energy's regulatory proposal does not propose any expenditure for demand management projects or trials in the next regulatory control period. However, the regulatory proposal implies Country Energy's 'Demand Management Program 2009–2014' and 'Intelligent Network Project' are currently undergoing programming and preparation for the next regulatory control period.

14.3.2 EnergyAustralia

14.3.2.1 Application of schemes

D–factor

EnergyAustralia stated it supported the AER's intention to continue the D–factor over the next regulatory control period.[645]

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[644] Country Energy, *Regulatory proposal*, appendix N.

EnergyAustralia stated it interprets clause 11.1 of the D–factor scheme[646] to mean any regulatory control period, and hence allows the inclusion of estimates of forgone revenues resulting from a reduction in demand due to demand management initiatives implemented in the current regulatory control period to be included in the D–factor calculations in the next regulatory control period.[647] EnergyAustralia stated this is consistent with the intention and historic operation of the D–factor scheme.

EnergyAustralia stated it will seek and submit independent experts' reports to demonstrate the reasonableness of any ongoing forgone revenue impacts associated with previous demand management initiatives.[648] EnergyAustralia provided to the AER independent experts' reports on its D–factor calculation and applications to IPART for years 2004–05, 2005–06 and 2006–07.[649]

Demand management innovation allowance

EnergyAustralia stated it supports the AER's proposed DMIA, however, maintains its preference for a more generous incentive scheme. EnergyAustralia proposed a number changes to the original DMIA:

- any unspent amount of the DMIA in a regulatory year should be rolled forward into the DMIA cap for the next regulatory year
- any unspent amount of the DMIA at the end of the next regulatory control period should be rolled forward and made available to DNSPs over the subsequent regulatory control period
- the DMIA should include a recognition for the time value of money invested in innovation projects, consistent with the timing of investments within the post–tax revenue model (PTRM). EnergyAustralia proposed that capital investments undertaken within the DMIA be multiplied by one plus the nominal vanilla weighted average cost of capital (WACC)
- the DMIA should recognise the timing gap between the real value of operating expenditure (opex) under the DMIA and the real value of recovery for those projects. EnergyAustralia proposed that opex undertaken within the DMIA be multiplied by one plus the nominal vanilla WACC (effectively allowing opex and capex under the DMIA to earn the same return)
- forgone revenues arising from demand management initiatives undertaken within the DMIA should be claimable under the AER's D–factor scheme
- the pre–approval assessment and notification stage within the DMIA be not mandatory for a project to be considered for the final ex post review

645 EnergyAustralia, *Regulatory proposal,* p. 156.
646 EnergyAustralia has clarified this reference as: clause 11.1(e)1 of IPART, *NSW Electricity Distribution Pricing 2004–05 to 2008–09 - Final Determination*, NSW, June 2004, p. 18.
647 EnergyAustralia, *Regulatory proposal*, p. 158.
648 EnergyAustralia, *Regulatory proposal*, p. 158.
649 EnergyAustralia, *Regulatory proposal*, Attachment 14.1.

- the AER clarify that demand management initiative milestones that occur in a regulatory year be calculated as part of the DMIA for that regulatory year, even though completion of the demand management initiative may be in a subsequent year (to ensure that a demand management initiative which spans a number of years is eligible for cost recovery up to the annual cap across each of the regulatory years, rather than the total costs for an initiative being recoverable under the DMIA for the year in which the initiative is completed)

- the AER ensure that the administration of the next regulatory control period DMIA be carried over into the subsequent regulatory control period until such time that all initiatives commenced within the next regulatory control period have been completed or the total funding allowance under the DMIA be exhausted

- the approved DMIA for each regulatory year be added to the approved D–factor for that regulatory year and then the combined value applied to the weighted average price cap (WAPC) via the existing D–factor mechanism (to avoid the DMIA amount being rounded out of the WAPC in the annual price–setting process).[650]

EnergyAustralia also proposed that the AER apply an 'I–factor' to allow cost recovery of $5 million per annum for network based innovations that are not readily foreseeable or quantifiable at the beginning of the regulatory control period. EnergyAustralia proposed that the 'I–factor' would provide incentives for a DNSP to carry out broad–based network related demand management innovations, such as asset management and communications improvement. EnergyAustralia proposed that the 'I–factor' operate as an extension to the AER's DMIA.[651]

14.3.2.2 Demand management initiatives

EnergyAustralia proposed to spend a total of $33 million on demand management projects over the next regulatory control period.[652]

EnergyAustralia's regulatory proposal also included its D–factor submissions for the years 2004–05, 2005–06 and 2006–07. These submissions detail demand management initiatives carried out by EnergyAustralia in those years, including:[653]

- power factor correction programs

- installation of embedded generation in the network

- compact fluorescent lamp programs

- identification of standby generation potential with large customers

- load interruptibility contracts with large customers.

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650 EnergyAustralia, *Regulatory proposal*, attachment 14.2.
651 EnergyAustralia, *Regulatory proposal*, pp. 157–158.
652 EnergyAustralia, response to a request for further information made by the AER on 21 July 2008, 1 August 2008.
653 EnergyAustralia, *Regulatory proposal*, attachment 14.1.

Impact on capital expenditure

EnergyAustralia submitted that as the regulatory framework for demand management is set to continue from the current regulatory control period into the next regulatory control period, it expects the likely deferral impact of demand management on EnergyAustralia's capex program to continue.[654] Based on its past experience with demand management, EnergyAustralia expects its non–tariff based demand management projects to result in the deferral of approximately $53 million of capex from the next regulatory control period into the subsequent regulatory control period.[655]

EnergyAustralia proposed to continue its time–of–use tariff based demand management program over the 2009–14 regulatory control period. EnergyAustralia estimated this program will result in a total reduction in augmentation capex of $29 million ($2006–07) in 2013–14.[656]

14.3.3 Integral Energy

14.3.3.1 Application of schemes

D–factor

Integral Energy stated it supports the AER's continuation of the D–factor scheme in NSW for the next regulatory control period.[657]

Demand management innovation allowance

Integral Energy stated the AER's introduction of the DMIA is a positive move to encourage demand management innovation, and it intends to undertake innovative tariff and non–tariff based demand management programs during the next regulatory control period.[658]

Integral Energy submitted it seeks an increase in the annual allowance from $0.6 million per annum to $1 million per annum to support a higher level of innovative demand management activity for the benefit of consumers.[659] Integral Energy submitted the proposed increase in the allowance aligns its allowance with that of EnergyAustralia, and reflects Integral Energy's view that the relative sizes of the DNSPs should not reduce the amount of funding for demand management.

14.3.3.2 Demand management initiatives

Integral Energy proposed spending of $1.5 million in opex and $1.5 million in capex per annum for small scale pricing trials over the next regulatory control period.[660] It also proposed that trials of a significant scale be treated as cost pass through events. The AER's consideration of Integral Energy's nominated pass through events is provided in chapter 15.

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654 EnergyAustralia, *DM impact on 2009-14 capital forecast*, April 2008, p. 6.
655 EnergyAustralia, *DM impact on 2009-14 capital forecast*, p. 8.
656 EnergyAustralia, *DM impact on 2009-14 capital forecast*, p. 9.
657 Integral Energy, *Regulatory proposal*, pp. 195–196.
658 Integral Energy, *Regulatory proposal*, p. 196.
659 Integral Energy, *Regulatory proposal*, p. 196.
660 Integral Energy, *Regulatory proposal*, p. 102.

Integral Energy also noted some minor opex associated with the project management of its demand management program, outlined below.[661]

Non–tariff based initiatives

Integral Energy detailed specific demand management initiatives implemented during the current regulatory control period, including:

- Castle Hill Commercial Centre—Integral Energy gained commitments from large customers to install more efficient lighting and air conditioning systems, and a carbon monoxide monitoring and exhaust fan control system to reduce the commercial centre's peak demand by 1300 kVA.

- Blacktown—Seven Hills (ongoing initiative)—Integral Energy is providing energy efficiency reviews for major business customers to find ways to save energy, which if implemented will result in Integral Energy subsidising the projects. To date, Integral Energy has achieved a peak demand reduction of 3720 kVA under this program.

- Wetherill Park—Integral Energy engaged a service provider to conduct audits of large customers and identify and implement efficiency initiatives, providing financial incentives and assistance for implementing the initiatives. This program resulted in a reduction in peak demand of 5550 kVA.

- Parramatta (ongoing initiative)—Integral Energy engaged a service provider to conduct audits and identify opportunities for large customer load shifting. To date, this program has resulted in a peak demand reduction of 2100 kVA.

- Blacktown and Westmead hospitals (ongoing initiative)—Blacktown Hospital commissioned a new cogeneration plant, for which Integral Energy has entered into an arrangement to operate at peak times in return for a financial payment. This program combined with other energy efficiency initiatives has resulted in a 680kVA reduction in peak demand. A similar program is underway with Westmead Hospital which, to date, has achieved a peak demand reduction of 2100 kVA.

- Unanderra (ongoing initiative)—Integral Energy appointed a consultant to conduct audits and identify opportunities for large customer energy efficiency, on–site generation and load shifting. To date, this program has resulted in an peak demand reduction of 2000 kVA.

- Liverpool (ongoing initiative)—Integral Energy appointed a consultant to conduct audits and identify opportunities for large customer energy efficiency, on–site generation and load shifting. To date, this program has resulted in a peak demand reduction of 1000 kVA.[662]

Integral Energy's regulatory proposal also detailed three pricing trials, initiated during the current regulatory control period, that are aimed at better understanding its customers' usage patterns and options to help achieve peak demand reductions. The trials include the

[661] Integral Energy, *Regulatory proposal*, p. 103.
[662] Integral Energy, *Regulatory proposal*, p. 94–96.

Western Sydney Pricing Trial, Blacktown Solar Cities trial and Advanced Metering Infrastructure trial.[663]

Tariff based initiatives

Integral Energy's regulatory proposal listed a number of tariff reforms implemented during the current regulatory control period:

- inclining block tariffs for residential and general supply customers
- a compulsory demand pricing policy for customers with annual consumption greater than 160MWh
- seasonal peak period maximum demand price structure for large customers on a network demand tariff
- voluntary time–of–use tariff for small customers.[664]

Integral Energy submitted in the next regulatory control period it intends to investigate a broad range of tariff reform options for existing network tariffs.[665]

14.4 Submissions

The AER received submissions from the Total Environment Centre (TEC), the Energy Users Association of Australia (EUAA), the Public Interest Advocacy Centre (PIAC), the Kiama Municipal Council and the Western Sydney Regional Organisation of Councils (WSROC).

Total Environment Centre

The TEC's submission stated the DNSPs' regulatory proposals contain excessive claims for capex, and minimal plans for demand management projects.[666]

The TEC stated it is the AER's responsibility to ensure that DNSPs select the most cost effective solution to meeting demand growth. It submitted that networks are becoming less efficient as regulators sit on the sidelines and allow networks to ignore demand management.[667]

The TEC submitted the D–factor scheme, despite providing a generous allowance for demand management costs and forgone revenues, has resulted in limited reductions in demand, and that demand management needs support from more than just 'soft incentives' to achieve an efficient level of demand management. The TEC stated the AER must implement aggressive rewards and penalties to ensure DNSPs prioritise demand

663 Integral Energy, *Regulatory proposal*, pp. 97–101.
664 Integral Energy, *Regulatory proposal*, p. 96.
665 Integral Energy, *Regulatory proposal*, p. 97.
666 TEC, *Submission to the Australian Energy Regulatory on NSW Distribution Network Service Providers Proposals 2009 – 2014, August 2008*, p. 2.
667 TEC, p. 3.

management, and that demand management incentive schemes are the most effective way of ensuring DNSPs implement demand management initiatives.[668]

The TEC recommended the following features for a demand management incentive scheme:[669]

- identification of demand management options and target outcomes, and the establishment of a pact between regulators and DNSPs
- inclusion of a fixed amount of funding for demand management to be included in the allowed revenues of DNSPs
- incorporation of a program of benefit sharing, and financial incentives and penalties
- implementation as part of a regulatory reset.

The TEC's submission included a report by Headberry Partners and Bob Lim and Co, titled *Does Current Electricity Network Regulation Actively Minimise Demand Side Responsiveness in the NEM*. The report stated there is an active bias against demand management in the regulatory regime. Specifically, it highlighted the following barriers to efficient demand management in the regulatory regime:[670]

- the rate of return on capital creates a bias against operating expenditure, of which demand management is largely composed
- the ex ante approach provides no assurance that networks have implemented demand management expenditure when equal or more cost effective than augmentation
- the service target performance incentive scheme (STPIS) discourages demand management
- the efficiency benefit sharing scheme (EBSS) encourages DNSPs to spend less on opex, of which demand management in largely composed
- price caps create incentives for DNSPs to increase demand and consumption of electricity, which creates disincentives for DNSPs to conduct demand management.

The TEC's submission also included two reports that the AER previously responded to in its final decision on the application of demand management incentive schemes, released on 29 February 2008.[671] These reports include a rule change package submitted to the AEMC in November 2007, and a report titled *Win Win Win: Regulating Electricity Networks for Reliability, Consumers and the Environment*. The AER's responses to these reports are available on the AER's website, www.aer.gov.au.

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668 TEC, p. 7.
669 TEC, pp. 12–13.
670 TEC, pp. 134–139.
671 AER, *Final Decision: DMIS.*

Energy Users Association of Australia

The EUAA submitted that it supported the AER's decision to continue the D–factor scheme in NSW and implement a DMIA for the ACT and NSW DNSPs. However, it stated that to date, demand management has had a small impact compared to supply side investments in the NEM. The EUAA submitted that the AER should seek robust demand management program impact assessments from the DNSPs, to ensure that the cost effectiveness of demand management programs can be clearly quantified.

The EUAA stated DNSPs' efforts towards demand management programs remain very limited, and the impact of demand management stunted. It stated the D–factor scheme has had limited impact on the amount of demand management carried out to date, and argued that the AER needs to ensure it plays a bigger role over the next regulatory control period.[672]

The EUAA submitted incentives provided to DNSPs to conduct demand management should be shared with users. Specifically, the EUAA submitted that there would be value in the AER signalling to the DNSPs that it expects them to involve end–users and aggregators in the development of demand management programs. It also submitted that the AER should provide certainty to the DNSPs that any demand management programs implemented will be subject to a continuing incentive for the life of the program.[673]

The EUAA noted the NSW Government has announced that it will continue retail price caps to 2013. The EUAA stated that it considers that this decision will blunt any incentives that could be provided to households through the installation of advanced meters and more cost reflective network tariffs. It submitted that the AER should take up this matter with the NSW Government to make it aware of the implications for DNSPs' capex over the next regulatory control period and the associated distribution price impacts.[674]

Public Interest Advocacy Centre

The PIAC submitted that the AER should take the DNSPs' consideration of demand management into account when assessing the increased capex programs within the regulatory proposals.[675]

Kiama Municipal Council

The Kiama Municipal Council submitted that only those who use air conditioners should pay for the costs associated with servicing peak loads due to air conditioner use, rather than such costs being smeared counterproductively across all users. It submitted that the AER should develop a pricing mechanism that penalises excessive energy consumption, and rewards customers who invest in reducing energy use.[676]

[672] EUAA, p. 17.
[673] EUAA, p. 17.
[674] EUAA, p. 18.
[675] PIAC, p. 2.
[676] Kiama Municipal Council, *Electricity Retailers' Proposal to Raise Household Electricity Costs EnergyAustralia, Integral Energy and Country Energy*, 28 July 2008, p. 2.

Western Sydney Regional Organisation of Councils

The WSROC submitted that governments should seek to shift the balance of costs for electricity away from fixed network charge components and towards usage components, to avoid a regime that supports high fixed prices, which could distort the incentives of the Federal Government's proposed emissions trading scheme.[677]

14.5 Issues and AER considerations

14.5.1 Application of demand management incentive schemes

14.5.1.1 D–factor

Issues raised by EnergyAustralia

As part of the AER's analysis of EnergyAustralia's regulatory proposal, the AER sought and received further information from EnergyAustralia in relation to clause 11.1 of the D–factor scheme.

The AER notes EnergyAustralia's comments relating to the treatment of forgone revenues and the intended and historic operation of the D–factor scheme. The AER has also consulted with IPART, which introduced the D–factor scheme in 2004, in relation to the issues raised by EnergyAustralia. IPART has confirmed that its intention in developing and applying the D–factor scheme to the NSW DNSPs was that forgone revenues incurred as a result of implementing demand management initiatives were recoverable under the scheme only up to the end of the regulatory control period in which the demand management initiatives were carried out. After the end of the regulatory control period, in this case after 30 June 2009, any expected falls in demand are anticipated to be accounted for in the demand forecasts for the next regulatory control period. This is also evidenced within IPART's D–factor guidelines, which the AER has adopted in reapplying the D–factor scheme to the NSW DNSPs:

> Where a demand management project results in reductions in revenue that extend beyond the end of that project, the DNSP may apply to recover the foregone revenue each year after the end of the project, up until the end of the regulatory period. After this time, any impact on sales volumes as a result of the demand management should be incorporated in demand forecasts for the subsequent regulatory period.[678]

The AER considers that the act of setting a DNSP's future revenue takes into account any anticipated future forgone revenues incurred from past demand management projects, through the process of assessment of future demand and associated augmentation capex.

During the course of the review EnergyAustralia implied that in planning and investigating the economic viability of its demand management projects during the current regulatory control period, it anticipated that forgone revenues for the demand management projects would be recoverable past the end of the current regulatory control

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677 WSROC, *Review of NSW DNSP Regulation Proposals for 2009-2014 – impacts of price increases on local government in Western Sydney, 20 August 2008*, p. 2.

678 IPART's Demand Management Consultation Group, *Guideline – Methodology for estimating foregone revenue*, April 2005, p. 3.

period.[679] This indicates to the AER that EnergyAustralia, in implementing demand management projects in the first three years of the current regulatory control period, assumed the AER would re-apply the D–factor to the NSW DNSPs. The AER did not make its decision on whether to apply the D–factor to the NSW DNSPs until 29 February 2008.

EnergyAustralia also pointed out IPART's inability to bind a future regulator, stating that IPART has consistently maintained a stance that it would not provide assurance that the D–factor would continue beyond the current regulatory control period. The AER considers that demand management projects implemented by EnergyAustralia in the first three years of the current regulatory control period have been implemented independent of the AER's decision to continue the D–factor scheme, or of the AER's intended operation of that scheme in future regulatory control periods. As such, the AER rejects EnergyAustralia's claim that demand management projects implemented in the current regulatory control period were implemented on the basis that the AER would allow recovery of associated forgone revenues into the next regulatory control period.

Issues raised within other proposals and submissions

Several submissions stated the D–factor has had a limited impact on the amount of demand management projects being carried out by DNSPs to date, despite providing a potentially generous incentive for DNSPs to conduct demand management. The AER considered the limited results of the D–factor to date in its final decision on the application of demand management incentive schemes, released on 29 February 2008. The final decision stated that modest claims to date for demand management programs carried out under the D–factor indicate that it may need more time to develop as an incentive mechanism.[680] The AER maintains its position that the D–factor may need more time to develop as an incentive mechanism, and its decision to apply the D–factor to the NSW DNSPs over the next regulatory control period is appropriate. The AER will continue to monitor the operation and results of the D–factor over the next regulatory control period, and will make its decision on whether the scheme should continue over the subsequent regulatory control period at the time of making its 2014 determinations for the NSW DNSPs.

14.5.1.2 Demand management innovation allowance

Issues raised by EnergyAustralia

Clause 6.6.3(c) of the transitional chapter 6 rules states that the AER may, from time to time, and with the agreement of each affected DNSP, amend or replace any published DMIS. The AER has considered the issues raised by EnergyAustralia relating to the design and operation of the DMIA, and proposes to amend the original DMIA published on 29 February 2008 to take account of many of the issues raised, by replacing it with the replacement DMIA set out in the AER's *Demand management incentive scheme for the ACT and NSW distribution determinations*, published in November 2008.

The AER notes EnergyAustralia's submission that any unspent amount of the DMIA in a regulatory year should be rolled forward into the DMIA cap for the subsequent regulatory

679 EnergyAustralia, *Regulatory proposal*, p. 158.
680 AER, *Final Decision: DMIS*, p. 6.

year.[681] The replacement DMIA allows unspent allowance from a regulatory year to be available for expenditure in any other regulatory year, up to the end of the regulatory control period.

EnergyAustralia submitted that any unspent amount of the DMIA at the end of the next regulatory control period should be rolled forward and made available to DNSPs over the 2014–19 regulatory control period. It also submitted that the AER should ensure that the administration of the 2009–14 DMIA be carried over into the 2014–19 regulatory control period, until such time that all initiatives commenced in the next regulatory control period have been completed, or the total funding under the DMIA be exhausted.[682] The AER considers these recommendations are not consistent with the objective of the scheme, which is to provide a modest level of financial support to defray some of the start–up costs of demand management in the next regulatory control period. The DMIA is not intended to be the sole source of funding for demand management projects in the next regulatory control period, rather it is to support the requirements for DNSPs to consider demand management where it is an efficient response to network constraints. The AER also considers EnergyAustralia's suggestions may result in fewer demand management projects being undertaken in the next regulatory control period, as DNSPs would be able to delay planned projects into the 2014–19 regulatory control period.

The AER notes EnergyAustralia's submission that the DMIA should include recognition for the time value of money invested in innovation projects that is consistent with the timing of investments within the PTRM, such that capex undertaken under the DMIA should be multiplied by one plus the nominal vanilla WACC.[683] EnergyAustralia also submitted that opex undertaken under the DMIA should be multiplied by one plus the nominal vanilla WACC. These suggestions would result in a significant increase in the demand management incentive generated by the DMIA. It would result in the effective double–recovery of costs under the scheme, as DNSPs would receive the principle costs within the allowance, as well as having expenditure rolled into the regulatory asset base (RAB) in the subsequent regulatory control period.

The AER considers that capex payments made under the replacement DMIA should be treated as capital contributions under clause 6.2.1.1 of the transitional chapter 6 rules, and therefore not rolled into the RAB at the start of the next regulatory control period. However, the AER's decision in that regard will only be made as part of its distribution determination for the 2014–19 regulatory control period. The AER considers that the replacement DMIA offers a sufficient incentive to meet the objective of the scheme, which is to provide a modest level of financial support to defray some of the start–up costs of demand management over the next regulatory control period.

EnergyAustralia submitted that the DMIA should recognise the timing gap between the real value of opex under the DMIA and the real value of recovery for those projects.[684] The end of period adjustment under the replacement DMIA takes into account the time value of money accrued or lost as a result of the expenditure profile selected by the DNSP, and accordingly addresses EnergyAustralia's concern.

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681 EnergyAustralia, *Regulatory proposal*, attachment 14.2, p. 3.
682 EnergyAustralia, *Regulatory proposal*, attachment 14.2, p. 3.
683 EnergyAustralia, *Regulatory proposal*, attachment 14.2, p. 3.
684 EnergyAustralia, *Regulatory proposal*, attachment 14.2, p. 3.

EnergyAustralia submitted that forgone revenues arising a reduction in demand due to demand management initiatives implemented under the DMIA should be claimable under the D–factor. It also submitted that the pre–approved allowance for each regulatory year should be added to the approved D–factor for that regulatory year, and the combined value applied to the weighted average price cap via the existing mechanism.[685] The AER considers that these suggested changes to the DMIA would result in the DMIA assisting DNSPs' demand management project expenditure to meet the materiality threshold within the D–factor scheme. This would undermine the incentives of both DMIS and result in fewer demand management projects, and the suggestion is therefore not accepted.

EnergyAustralia submitted that the pre–approval and notification stage within the DMIA should not be mandatory for a project to be considered for the ex post review under the scheme.[686] The replacement DMIA does not include a pre–approval and notification stage, and is therefore administratively simpler than the original DMIA proposed by the AER.

The AER notes EnergyAustralia's submission that the requirement for demand management project milestones should be clearer under the DMIA, and should ensure that a project that spans several years is eligible for cost recovery up to the annual cap across each of the regulatory years.[687] The replacement DMIA applies clearer criteria for cost recovery, and does not require demand management project milestones for each year.

EnergyAustralia suggested that the administration of the next regulatory control period DMIA be carried over into the subsequent regulatory control period until such time that all initiatives commenced within the next regulatory control period have been completed or the total funding allowance under the DMIA be exhausted.[688] The AER considers that this recommendation is not consistent with the replacement DMIA, which provides a modest allowance to defray some of the start–up costs of demand management in the next regulatory control period. The AER considers it important that the DMIA ensures DNSPs are indifferent in deciding which year to carry out demand management solutions, such that DNSPs will elect to undertake demand management when it is an efficient response to network constraints in any regulatory year. The administration of the replacement DMIA is guaranteed only up to the end of the next regulatory control period, at which time the AER will reconsider the DMIA and demand management incentives present in the broader regulatory framework at that time.

The AER considers that the DMIA and D–factor schemes should operate independently. The replacement DMIA operates as an ex ante allowance, and as such will not require an annual assessment for price movements. Rather a single adjustment carried out in the second year of the subsequent regulatory control period to account for the approved amount of demand management expenditure undertaken and forgone revenues. For DNSPs that are subject to a form of control where revenue is at least partially dependent on the quantity of electricity sold (such as a weighted average price cap), the replacement DMIA provides for the recovery of forgone revenues resulting from a reduction in demand due to approved demand management projects carried out under the scheme. The

685 EnergyAustralia, *Regulatory proposal*, attachment 14.2, pp. 3–4.
686 EnergyAustralia, *Regulatory proposal*, attachment 14.2, p. 4.
687 EnergyAustralia, *Regulatory proposal*, attachment 14.2, p. 4.
688 EnergyAustralia, *Regulatory proposal*, attachment 14.2, p. 4.

AER considers that the replacement DMIA will result in greater implementation of demand management projects over the next regulatory control period, as the allowance will not be eroded by the recovery of forgone revenues.

The AER notes EnergyAustralia's proposed 'I–factor' extension to the DMIA. The AER considers that implementing the 'I–factor' proposal would result in a significant increase in the incentives for DNSPs to conduct broad–based demand management, over and above the incentives created by the D–factor and DMIA. The AER considers that the application of both the replacement DMIA and the D–factor will provide sufficient incentives for NSW DNSPs to carry out broad–based demand management projects, and proposes not to implement EnergyAustralia's recommended 'I–factor' extension to the DMIA.

The DMIA is a relatively modest financial reward for a DNSP. It is not intended to replace or substitute for demand management initiatives currently being carried out, and is additional to the obligations on DNSPs to consider non–network alternatives to capex or opex imposed by the NER. The DMIA can, however, be used to finance set up costs associated with larger demand management projects. Given the modest size of the allowance provided, any underspend will not be rolled forward into the subsequent regulatory control period.

Issues raised within other proposals and submissions

The AER notes the suggestions made by Country Energy and Integral Energy that the allowances provided under the DMIA should be increased to support a higher number of demand management projects, and that they should not be based on the relative sizes of the DNSPs' revenues.

The AER considers it is appropriate to base the DMIA allowances on the relative sizes of the NSW DNSPs' revenues, as it considers each DNSP's efficient level of demand management will vary according to the size of their network and potential for deferral of network augmentation. The AER considered the magnitude of the allowances provided under the DMIA in its final decision on DMIS to apply to the ACT and NSW DNSPs.[689] In its final decision, the AER applied a five fold increase in the DMIA allowance from that proposed in the AER's December 2007 preliminary positions paper.[690] The AER considers that the allowance provided under the DMIA provides a sufficient incentive for each DNSP to further develop their demand management initiatives and experience over the next regulatory control period, and proposes not to increase the proposed allowances.

DNSPs have an obligation to undertake demand management where efficient, as part of normal business operations. The allowance is modest, recognising that it is provided in addition to demand management expenditures undertaken where they are efficient responses to network constraints. The DMIA is not a substitute for current expenditure on demand management.

The replacement DMIA

The replacement DMIA aims to provide incentives for the same types of demand management projects as the original scheme, being broad–based and/or innovative

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[689] AER, *Final Decision: DMIS*, pp. 18–20.
[690] AER, *Final Decision: DMIS*, pp. 18–20.

initiatives, however, it provides simpler, clearer guidelines for DNSPs seeking cost recovery under the scheme. The replacement DMIA also provides DNSPs with an opex allowance for demand management project implementation costs over the next regulatory control period, with the recovery of any unspent or inefficiently spent allowance in the subsequent regulatory control period.

The AER's replacement DMIA will provide DNSPs with an allowance of the same magnitude as the original scheme, however, it removes administrative complexities and provides for a fairer allocation of the allowance. The replacement DMIA allows the NSW DNSPs (subject to a weighted average price cap over the next regulatory control period), to recoup forgone revenues, in addition to the allowance provided under the scheme, and provides clear guidelines as to the process by which forgone revenues will be assessed by the AER. This will result in more demand management projects being supported by the DMIA, as the allowance will not be eroded by the recovery of forgone revenues. Overall, the AER considers the replacement DMIA creates a more constant incentive for DNSPs to conduct demand management over the course of the regulatory control period.

14.5.2 Demand management expenditure and incentives

Several regulatory proposals and submissions noted demand management has had a limited impact on DNSPs' network planning and investment when compared to supply side investments.

The AER notes the very large capex proposals made by the DNSPs for the next regulatory control period. Clause 6.5.7(e)(10) of the transitional chapter 6 rules requires the AER to consider the extent to which a DNSP has considered, and made provision for, efficient non–network alternatives in deciding whether the total forecast capex reasonably reflects the capex criteria in the transitional chapter 6 rules. The NSW DNSPs' proposals contain details of planning and capital governance processes that include a requirement for consideration of efficient non–network alternatives in capital planning processes. Wilson Cook has confirmed that these processes are being followed in assessing solutions to emerging network constraints.[691] The regulatory proposals also contain strategic demand management plans that detail DNSPs' incorporation of demand management projects in network planning. The AER's consideration of the capex criteria is considered in chapter 7.

The AER notes the TEC's submission that DMIS are the most effective way of ensuring DNSPs implement demand management initiatives, and its suggestions regarding optimal features for DMIS. The AER's replacement DMIA identifies demand management target outcomes, and provides upfront funding for demand management within DNSPs' revenues at the time of regulatory reset. While the DMIA does not include penalties for DNSPs who elect not to consider demand management, clause 6.5.7(e)(10) of the transitional chapter 6 rules requires the AER to consider the extent a DNSP has considered, and made provision for, efficient non–network alternatives in deciding whether the total forecast capex reasonably reflects the capex criteria of the transitional chapter 6 rules. The AER's DMIS aim to provide positive incentives for DNSPs to conduct demand management. The AER proposes not to apply penalties for DNSPs that do not undertake demand management under the schemes.

[691] Wilson Cook, volume 2, p. 26; volume 3, p. 16; volume 4, p. 15.

The TEC highlighted barriers to demand management within the regulatory regime. The AER considered the barriers to efficient demand management in documents leading up to its final decision on DMIS to apply to the ACT and NSW DNSPs over the next regulatory control period.[692] Barriers to demand management were also considered by the AER during the development of the original and replacement DMIA.

The AER considered the EUAA's submission that it should seek robust demand management program impact assessments to ensure the cost effectiveness of demand management projects can be quantified. Both the D–factor and DMIA require DNSPs to demonstrate the efficiency of their demand management expenditure for cost recovery under the schemes. To receive demand management incentive payments under the D–factor, DNSPs must demonstrate a reasonable expectation of a corresponding reduction in demand, and a deferral of network expenditure. In this way, both schemes require DNSPs to ensure demand management projects are cost effective, and the AER considers it is unnecessary at this time to increase the reporting requirements surrounding demand management expenditure.

The EUAA also submitted that the incentives provided to DNSPs to conduct demand management should be shared with users, and that the AER should signal to the DNSPs that it expects them to involve end users and demand side aggregators in demand management programs. A large number of demand management programs carried out by DNSPs to date have included end user education initiatives, as well as the provision of energy efficient light globes and free assessments of customers' residences and businesses to determine the potential for energy savings. In addition, the AER understands that there are a number of demand–side aggregators operating in NSW, working to develop contractual arrangements with DNSPs for demand management services. The AER notes that DNSPs are currently conducting programs to encourage customers to improve energy efficiency and share demand management incentives with end users and demand–side aggregators as part of such initiatives.

The EUAA submitted that the AER should provide certainty to DNSPs that any demand management programs implemented will be subject to a continuing incentive for the life of the program. The aim of the DMIA is to provide incentives for DNSPs to conduct broad–based and innovative demand management projects over the next regulatory control period. It aims to build DNSPs' experience with demand management, such that in future regulatory control periods, demand management may be seen as a reliable, tested response to rising peak demand, and an integral part of network decision–making processes. The AER's demand management incentive framework is built around a five year regulatory cycle. At the end of the next regulatory control period, DNSPs will have an opportunity to propose efficient demand management projects in opex and capex proposals for the subsequent regulatory control period, based on the experience gained within the next regulatory control period. The AER considers that it is not necessary to extend commitments to financial incentives for demand management projects beyond the next regulatory control period. A commitment to provide an ongoing incentive might result in inefficient demand management projects being maintained.

[692] AER, *Issues Paper - Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–14,* November 2008, *Preliminary Positions Paper - Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–14* December 2008, and *Final Decision: DMIS.*

The AER considered the EUAA's statement that the AER should consult with the NSW Government on its decision to continue retail price caps to 2013. The AER notes that retail price regulation is outside of its role as economic regulator of electricity transmission and distribution networks.

The Kiama Municipal Council submitted that the AER should develop a pricing mechanism that penalises excessive energy consumption and rewards customers who invest in reducing energy use. The WSROC submitted that governments should seek to shift the balance of costs for electricity away from fixed network charge components and towards usage components. The AER's DMIS provide incentives for both tariff and non–tariff demand management projects, including pricing trials as described by the Kiama Municipal Council. The AER assesses the DNSPs' pricing proposals and structures at the time of making its annual pricing determinations. The NSW DNSPs must submit their pricing proposals, including proposed pricing structures, for regulatory year 2009–10 within 15 business days after publication of the AER;s final distribution determinations for those DNSPs for the 2009–14 regulatory control period.[693]

14.6 AER conclusions

The AER maintains its decision to apply the D–factor scheme to the NSW DNSPs over the next regulatory control period, in the form applied by IPART over the current regulatory control period. The AER rejects EnergyAustralia's claim that forgone revenues associated with demand management projects implemented in the current regulatory control period should be recovered in the next regulatory control period under the D–factor scheme.

The AER's draft decision, subject to the agreement of Country Energy, EnergyAustralia and Integral Energy (as the affected DNSPs), is to amend the DMIA applied in its final decision on DMIS, released on 29 February 2008, by replacing it with the replacement DMIA.[694]

The AER seeks submissions from Country Energy, EnergyAustralia and Integral Energy on the replacement DMIA. If Country Energy, EnergyAustralia and Integral Energy agree that the original DMIA is to be replaced by the replacement DMIA, the AER seeks written confirmation of each DNSPs' agreement for the purposes of clause 6.6.3(c) of the transitional chapter 6 rules.

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693 Transitional chapter 6 rules, clause 6.18.2(a)(1).
694 AER, *DMIS-DMIA*.

14.7 AER draft decision

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the AER decides that, with the agreement of Country Energy the demand management incentive scheme to apply to Country Energy is the DMIA set out in the AER's *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme,* November 2008, and the D–factor scheme set out in IPART's *Guidelines on the Application of the D–factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination*.

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the AER decides that, with the agreement of EnergyAustralia the demand management incentive scheme to apply to EnergyAustralia is the DMIA set out in the AER's *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme,* November 2008, and the D–factor scheme set out in IPART's *Guidelines on the Application of the D–factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination*.

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the AER decides that, with the agreement of Integral Energy the demand management incentive scheme to apply to Integral Energy is the DMIA set out in the AER's *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme,* November 2008, and the D–factor scheme set out in IPART's *Guidelines on the Application of the D–factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination*.

In accordance with clause 6.3.2(a)(3) of the transitional chapter 6 rules, the AER decides that the application of the demand management incentive scheme to apply to the NSW DNSPs is as specified in section 14.6 of the draft decision.

15 Pass through arrangements

15.1 Introduction

This chapter sets out the AER's assessment of the NSW DNSPs' proposed pass through events to apply during the next regulatory control period.

An objective of the incentive framework is to ensure that risks are appropriately managed. If a DNSP fails to manage risks properly and incurs additional costs it would be expected to bear those costs. However, the NER recognises that the DNSPs are exposed to risks beyond their control which may have a material impact on their costs. In some cases the risk may be symmetrical in which case costs could potentially increase or decrease.

One means of dealing with such outcomes is the pass through provisions contained in the NER. These provisions allow material changes (both increases and decreases) in the costs of providing direct control services to be passed through to distribution network users during a regulatory control period if certain events occur.[695] This pass through of costs is achieved through an amendment to the price or revenue determination.

15.2 Regulatory requirements

The transitional chapter 6 rules allow for two categories of pass through events in electricity distribution:

- Defined events—the following four events set out in chapter 10 of the NER as pass through events:
  - a regulatory change event
  - a service standard event
  - a tax change event
  - a terrorism event.
- Nominated pass through events—other events that the DNSPs may propose to the AER to include as nominated pass through events in its distribution determination.

Pass through events can be both positive and negative. A positive change event is a pass through event that materially increases the costs of providing direct control services. If this occurs a DNSP may seek the approval of the AER to pass through to distribution network users a positive pass through amount under clause 6.6.1(a) of the transitional chapter 6 rules.

A negative change event is a pass through event that materially reduces the costs of providing direct control services. If this occurs a DNSP must notify the AER of the details of the event and the negative pass through amount. After becoming aware that a

[695] For EnergyAustralia, direct control services include prescribed (transmission) standard control services.

negative change event has occurred, the AER must determine a negative pass through amount under clause 6.6.1(g) of the transitional chapter 6 rules.

Pass through adjustments within the regulatory control period

Clause 6.6 of the transitional chapter 6 rules outlines the procedure for making pass through adjustments after the making of a distribution determination.

If the AER determines that a pass through event has occurred, the AER must determine the pass through amount and how that amount is to be recovered over the remainder of the regulatory control period (clause 6.6.1(d) of the transitional chapter 6 rules for positive change events and clause 6.6.1(g) for negative change events). The factors that the AER is required to take into account in determining the pass through amount are contained in clause 6.6.1(j). These include an efficiency test, including whether the DNSP could have taken any reasonable measures to minimise cost increases.

15.3 NSW DNSP proposals

15.3.1 Country Energy

Country Energy proposed that the following six events be included as nominated pass through events in the AER's distribution determination:

- new or additional market requirements (such as the mandatory rollout of interval meters and the consequent significant data handling costs)
- 'Intelligent network' investments
- events that potentially could be classified as self insurance events
- changes in risk assessment costs due to court cases and other legal obligations
- changes to obligations, structure and costs due to outcomes of the retail reform project
- input cost variations.[696]

Mandatory roll out of smart meters

Country Energy proposed that any mandated smart metering rollout within its network area be specified as a nominated pass through event. Country Energy is of the view that the trigger for the mandated smart meter rollout occurring should be defined in this distribution determination as the time when the distributor has been able to firm up all costs, benefits and impacts to the point where a full business case can be presented to the AER.[697]

[696] Country Energy, *Regulatory proposal*, p. 167.
[697] Country Energy, *Regulatory proposal*, p. 167.

'Intelligent network' investments

Country Energy requested that the potential deployment of intelligent network infrastructure be recognised as a nominated pass through event.[698]

Self insurance events

Country Energy has identified the following events that could potentially be self insured for, but considered that the risks of these events were more appropriately covered in the pass through provisions:

- an asbestos related event
- climate change risks event
- gradual pollution event
- electric and magnetic fields (EMF) event
- business continuity event
- retailer of last resort event
- workers compensation premium event.[699]

Changes in risk assessment costs due to court cases and other legal obligations

Country Energy cited a recent case (the Sheather Case) in which the NSW Court of Appeal found Country Energy to have breached its duty of care, despite the network operator complying with the relevant Australian Standards in relation to the powerlines. Country Energy asked the AER to include a nominated pass through event for legal obligations which are imposed on it and which do not fall within any of the defined events under the NER.[700]

Changes to obligations, structure and costs due to outcomes of the retail reform project

Country Energy stated that the potential sale of its retail business needs to be incorporated as a nominated pass through event. Similar to the rollout of smart meters, Country Energy is of the view that the trigger for a retail reform pass through event should be at the time when the distributor has been able to firm up all costs, benefits and impacts to the point where a full business case can be presented to the AER.[701]

Input cost variations

Country Energy considered that there may be scope to nominate significant input cost variations as pass through events. It noted that input cost variations treated as pass

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698 Country Energy, *Regulatory proposal*, p. 168.
699 Country Energy, *Regulatory proposal*, pp. 170–171.
700 Country Energy, *Regulatory proposal*, pp. 169–170.
701 Country Energy, *Regulatory proposal*, p. 170.

through events would not influence carryover amounts for the operation of the EBSS as pass through events are excluded from the operation of the EBSS.[702]

Network support payments

This cost area includes network support payments to embedded generators connected to the Country Energy network. These generators provide network support services in the form of local generation and the provision of reactive power. Future network support payments by Country Energy have not been included in its operating and maintenance expenditure forecasts, and therefore Country Energy has proposed to include them as a pass through event.[703]

15.3.2 EnergyAustralia

EnergyAustralia proposed that the following seven events be included as pass through events:[704]

- force majeure event
- cost or demand variance event
- joint planning event
- separation event
- compliance event
- customer connection event
- dead zone event.

EnergyAustralia summarises each of its nominated pass through events in its regulatory proposal. These summaries are reproduced below. Full definitions of these nominated pass through events are contained in attachment 15.1 to EnergyAustralia's regulatory proposal.

Force majeure event

EnergyAustralia described a force majeure event as:

> Any fire, flood, earthquake, storm or other weather-related event or natural disaster, act of God, riot, civil disorder or rebellion or other similar cause beyond the reasonable control of EnergyAustralia that occurs during a regulatory control period and materially increases the cost to EnergyAustralia of providing standard control services including prescribed (transmission) standard control services.[705]

Cost or demand variance event

EnergyAustralia described a cost or demand variance event as:

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702 Country Energy, *Regulatory proposal*, p. 170.
703 Country Energy, *Regulatory proposal*, p. 170.
704 EnergyAustralia, *Regulatory proposal*, pp. 162–165.
705 EnergyAustralia, *Regulatory proposal*, p. 163.

> An event involving any change in actual cost movements or demand during the regulatory control period from cost movements or demand forecasts used in EnergyAustralia's expenditure forecasts (as accepted or substituted by the AER) that materially increases or decreases the cost to EnergyAustralia of providing standard control services including prescribed (transmission) standard control services.[706]

Joint planning event

EnergyAustralia described a joint planning event as:

> An event involving a change to a capital project the subject of joint planning between EnergyAustralia and TransGrid, or EnergyAustralia and another NSW DNSP, or a new project relevant to joint planning that is beyond EnergyAustralia's reasonable control and materially increases or decreases the costs to EnergyAustralia of providing standard control services including prescribed (transmission) standard control services.[707]

Separation event

EnergyAustralia described a separation event as:

> A separation event is any legislative or administrative act or decision to separate any business or function of EnergyAustralia in whole or in part from any other business or function of EnergyAustralia (including by way of a sale of EnergyAustralia's retail business), which materially increases or decreases the costs to EnergyAustralia of providing standard control services, including EnergyAustralia prescribed (transmission) standard control services.[708]

Compliance event

EnergyAustralia described a compliance event as:

> An event other than a service standard event or a regulatory change event involving:
>
> - a change in a compliance obligation (meaning a general law obligation or a requirement of a non-mandatory code, standard or guideline which represents standards acceptable to the workforce or to the community)
> - a change in the way a compliance obligation is interpreted, or
> - any new compliance obligation
>
> which materially increases or decreases the cost to EnergyAustralia of providing standard control services including prescribed (transmission) standard control services.[709]

Customer connection event

EnergyAustralia described a customer connection event as:

[706] EnergyAustralia, *Regulatory proposal*, p. 163.
[707] EnergyAustralia, *Regulatory proposal*, p. 164.
[708] EnergyAustralia, *Regulatory proposal*, p. 165.
[709] EnergyAustralia, *Regulatory proposal*, p. 164.

> A customer connection event is a transmission or subtransmission network connection for a developer, an end-use customer or a generator, or a requirement for EnergyAustralia to establish a new substation to supply load requested by a developer or end-use customer that materially increases or decreases the costs, relative to those allowed in the proposal, to EnergyAustralia of providing standard control services including prescribed (transmission) standard control services.[710]

Dead zone event

EnergyAustralia described a dead zone event as:

> Any pass through event that occurs during the 2004-2009 regulatory control period and has a cost impact in the next regulatory control period, that has not been included in EnergyAustralia's capital and operating expenditure forecasts (as accepted or substituted by the AER) for that period.[711]

15.3.3 Integral Energy

Integral Energy proposed that the following 12 events be included as pass through events:[712]

- an asbestos event
- an automated interval meters event
- a business continuity event
- a change in ownership event
- a change in reporting requirements event
- a distribution loss event
- an EMF event
- an emissions trading scheme event
- a functional change event
- a gradual pollution event
- a retailer of last resort event
- a sabotage event.

Asbestos event

Integral Energy defined an asbestos event as:

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710 EnergyAustralia, *Regulatory proposal*, p. 165.
711 EnergyAustralia, *Regulatory proposal*, p. 162.
712 Integral Energy, *Regulatory proposal*, pp. 181–182.

> An asbestos event occurs if, during the course of the regulatory control period Integral Energy becomes liable for any claims arising from the presence of asbestos or any asbestos materials in any of its assets or the use of asbestos or any asbestos related materials in its operations including claims by present and former employees of Integral Energy and/or third parties and as a consequence, the costs to Integral Energy of providing direct control services are materially increased.[713]

Automated interval meters event

Integral Energy defined an automated interval meter event as:

> An automated interval meters event is an event which results in Integral Energy being required to install automated interval meters (otherwise known as smart meters) for some or all of its customers or to conduct large scale metering trials during the course of the regulatory control period, regardless of whether that requirement takes the form of the imposition of a statutory obligation or not, and which:
>
> (a) falls within no other category of pass through event; and
>
> (b) materially increases the costs of Integral Energy providing the direct control services.[714]

Business continuity event

Integral Energy defined a business continuity event as:

> A business continuity event occurs if during the course of the regulatory control period an event occurs which significantly impacts the ability of Integral Energy to provide direct control services in accordance with its usual operations, regardless of whether the event impacts a specific region or section of the population or is more widespread, and as a consequence of that event, the costs to Integral Energy of providing direct control services are materially increased.[715]

Change in ownership event

Integral Energy defined a change in ownership event as:

> A change in ownership event occurs if during the course of the regulatory control period there is a change to the ownership of Integral Energy's retail electricity business and as a consequence the costs to Integral Energy of providing direct control services are materially increased.[716]

Change in reporting requirements event

Integral Energy defined a change in reporting requirements event as:

> A change in reporting requirements event is an event which results in the imposition of additional reporting requirements on Integral Energy as a Distribution Network Service Provider to the Australian Energy Regulator or any other regulator which:
>
> (a) occurs during the regulatory control period

[713] Integral Energy, *Regulatory proposal*, p. 184.
[714] Integral Energy, *Regulatory proposal*, p. 184.
[715] Integral Energy, *Regulatory proposal*, p. 184.
[716] Integral Energy, *Regulatory proposal*, pp. 184–185.

(b) falls within no other category of pass through event; and

(c) materially increases the costs of Integral Energy providing the direct control services.[717]

Distribution loss change event

Integral Energy defined a distribution loss change event as:

> A distribution loss change event is an event which results in the imposition of costs or legal obligations on Integral Energy in relation to distribution losses from the operation of its distribution network which:
>
> (a) occurs during the regulatory control period
>
> (b) falls within no other category of pass through event; and
>
> (c) materially increases the costs of Integral Energy providing the direct control services.[718]

Integral Energy has proposed this pass through event to cover circumstances in which financial responsibility for distribution losses is transferred to network businesses or an emissions charge is imposed in relation to distribution losses as part of the Federal Government's greenhouse policy.

Electric and magnetic fields event

Integral Energy defined an EMF event as:

> An electric and magnetic fields event occurs if during the course of the regulatory control period either of the following types of events occur:
>
> (a) Integral Energy becomes liable for any claims directly related to electric and magnetic fields from any of the assets it owns and operates or has owned and operated including claims by present and former employees of Integral Energy and/or third parties; or
>
> (b) the manner in which Integral Energy undertakes 'live-line' work is affected due to the potential exposure of the people undertaking this work to electric and magnetic fields,
>
> and as a consequence of that event, the costs to Integral Energy of providing direct control services are materially increased.[719]

Emissions trading scheme event

Integral Energy defined an emissions trading scheme event as:

> An emissions trading scheme event is an event which results in the imposition of legal obligations on Integral Energy arising from the introduction or operation of a carbon emissions trading scheme by the Commonwealth during the course of the regulatory control period and which:
>
> (a) falls within no other category of pass through event

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[717] Integral Energy, *Regulatory proposal*, p. 185.
[718] Integral Energy, *Regulatory proposal*, p. 185.
[719] Integral Energy, *Regulatory proposal*, p.185.

(b) materially increases the costs of Integral Energy providing the direct control services.[720]

Functional change event

Integral Energy defined functional change event as:

> A functional change event is an event which results in the imposition of new obligations, or changes the nature of the existing obligations, on Integral Energy as a Distribution Network Service Provider which:
>
> (a) occurs during the regulatory control period
>
> (b) falls within no other category of pass through event
>
> (c) materially increases the costs of Integral Energy providing the direct control services.[721]

Gradual pollution event

Integral Energy defined a gradual pollution event as:

> A gradual pollution event occurs if during the course of the regulatory control period either of the following events occur:
>
> (a) Integral Energy becomes liable for any claims directly arising from the conduct of its network operations which resulted in the pollution of the surrounding environment
>
> (b) the manner in which Integral Energy undertakes its network operations is affected due to the unacceptable risk of polluting the surrounding environment;
>
> and as a consequence of that event, the costs to Integral Energy of providing direct control services are materially increased.[722]

Retailer of last resort event

Integral Energy defined a retailer of last resort event as:

> A retailer of last resort event is an event which results in the imposition of costs or legal obligations on Integral Energy relating to the Retailer of Last Resort scheme under the Electricity Supply Act 1995 (NSW) and which event:
>
> (a) occurs during the regulatory control period
>
> (b) falls within no other category of pass through event; and
>
> (c) materially increases the costs of Integral Energy providing the direct control services.[723]

Sabotage event

Integral Energy defined a sabotage event as:

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720 Integral Energy, *Regulatory proposal*, p. 185.
721 Integral Energy, *Regulatory proposal*, pp. 185–186.
722 Integral Energy, *Regulatory proposal*, p. 186.
723 Integral Energy, *Regulatory proposal*, p. 186.

> A sabotage event occurs if an act (including but not limited to, the use of force or violence or the threat of force or violence) of any person or group of persons (whether acting alone or on behalf of or in connection with any organisation or government) materially increases the costs to Integral Energy of providing direct control services and that event is not a terrorism event under the Rules.[724]

15.4 Submissions

The EUAA submitted that pass through events need to be tightly defined so that risks are appropriately shared between DNSPs and consumers and that DNSPs should not use pass through events to remove all risk.[725]

In response EnergyAustralia submitted:

> A pass-through mechanism has been established in the Rules for a specific purpose of providing a risk management mechanism. EnergyAustralia has proposed pass-through events as part of its regulatory proposal, which it believes manages risks outside of the control of the business and to which non-regulated entities would be able to pass through.[726]

15.5 Consultant review

Wilson Cook considers that only exceptional events should be included as pass through events. Wilson Cook stated:

> We suggest that additional pass-through proposals are not to be recommended unless they are of a type that a prudent DNSP would not normally provide for in its expenditure estimates. We suggest such proposals should meet a high threshold in that respect. In essence, we suggest that the potential events ought to be exceptional in nature. Normal or foreseeable business risks, including risks that an owner of the business ought to bear, should be excluded.[727]

Of the nominated events Wilson Cook only commented on the introduction of smart meters. Wilson Cook was concerned that the inclusion of the costs of smart meters as a pass through event may remove the incentive for DNSPs to argue against the introduction of smart meters if they do not consider the expenditure to be beneficial. However, Wilson Cook noted that the DNSPs would have no choice if the introduction of smart meters was legislated, in which case it would be a defined event.[728]

15.6 Issues and AER considerations

15.6.1 Criteria for assessing nominated events

The AER must decide whether the events proposed by the NSW DNSPs in their regulatory proposals should be included in the AER's distribution determination as pass through events. In deciding whether or not to include an event proposed by the NSW DNSPs as a pass through event the AER will consider whether:

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[724] Integral Energy, *Regulatory proposal*, p. 186.
[725] EUAA, p. 19.
[726] EnergyAustralia, *Response to request for submissions*, p. 15.
[727] Wilson Cook, volume 1, p. 13.
[728] Wilson Cook, volume 3, p. 46.

- the event is already captured by the defined event definitions
- the event is clearly identified
- the event is uncontrollable (that is, a prudent service provider through its actions could not have reasonably prevented or substantially mitigated the event)
- despite the event being foreseeable, the timing and/or cost impact of the event could not be reasonably forecast by the relevant NSW DNSP at the time of submitting its regulatory proposal
- the event is not already insured for (either external or self-insured)
- the event cannot be self-insured because a self insurance premium cannot be calculated or the potential loss to the relevant NSW DNSP is catastrophic
- the party who is in the best position to manage the risk is bearing the risk
- the passing through of the costs associated with the event would undermine the incentive arrangements within the regulatory regime.

15.6.2 Proposed nominated pass through events that the AER accepts

The AER's accepts the following events as pass through events:

- retail project event
- force majeure event.

As provided for in the transitional rules chapter 6 rules (clause 6.6.1(j)(3)), in any application for a pass through amount in relation to these events, the DNSP must demonstrate that it has taken all reasonable measures to reduce the magnitude of the pass through amount.

Retail project event

If the NSW electricity retail businesses are privatised the DNSPs' costs of providing direct control services may increase due to loss of synergies. The AER considers that privatisation is likely to occur as a result of an administrative decision of the NSW Government, which would not be covered by the definition of a regulatory change event. Accordingly, it is appropriate that this event should be included as a pass through event. EnergyAustralia's proposed separation event also falls within this category.

The AER considers that this proposed event meets the AER's assessment criteria and therefore accepts a retail project event as a nominated pass through event.

In addition to changes to on-going operating costs, a retail project event is also likely to involve transaction costs relating to the sale of assets. While the AER will consider an application for a pass through amount on its merits at the time, the AER's view is that the buyer and seller should bear their respective transaction costs.

Force majeure event

A force majeure event is an uncontrollable event and often difficult to cover with insurance (either externally or through self insurance). The AER considers passing through the costs of a force majeure event meets the AER's assessment criteria and therefore it accepts a force majeure event as a nominated pass through event. It also considers that Integral Energy's proposed business continuity event is similar to a force majeure event.

15.6.3 Proposed events that the AER does not accept as nominated pass through events

The AER considers that following proposed pass through events are likely to be regulatory change events and therefore it considers that separate nominated events are unnecessary:

- the introduction of smart meters
- the introduction of an emissions trading scheme
- distribution loss event
- retailer of last resort
- obligations relating to EMF
- changes in reporting requirements.

The AER considers that the defined events contained in the transitional chapter 6 rules were designed to cover these types of events.

Wilson Cook expressed concerns that inclusion of the introduction of smart meters as a nominated pass through event may undermine incentives for the DNSPs to argue against the introduction of smart meters if they did not consider it to be cost effective. However, Wilson Cook noted that the DNSPs would have no choice if the introduction of smart meters was legislated, in which case it would be a defined event. The AER has similar concerns with the other proposed pass through events listed above.

The AER does not accept the remaining proposed pass through events for the reasons below.

Compliance events (including court decisions) and functional events

The AER has concerns with the broad nature of these proposed pass through events. It does not consider that the intent of the NER is to allow the DNSPs the opportunity to pass through cost changes associated with all unforeseen events that may occur during the regulatory control period. Instead, the AER considers that intention of the NER is to allow the costs associated with specific major unforeseen events outside the control of the DNSPs to be passed on to customers.

How the DNSPs respond to events of this nature, such as a court decisions, is a matter for the management of the DNSP. While the DNSP may not be able to control the outcome of the event, if it decides to change its operations then that is at the discretion of management. In those cases the DNSP has some control over its expenditure. The AER considers that under these circumstance the most appropriate time for the DNSP to seek to pass any cost changes through to users is at the next regulatory reset.

Moreover, the AER considers that the concerns expressed by Wilson Cook in relation to smart meters are also relevant to these proposed events. That is, the introduction of obligations on DNSPs as 'compliance' or 'functional' events may act as a disincentive to the DNSPs to argue against their introduction if they did not consider the event to be economically efficient. However, if those obligations were imposed on DNSPs as regulatory change events, the DNSPs would have no option.

Dead zone events

EnergyAustralia has proposed this event to cover any pass through events that occur in the intervening period between the date that it lodged its proposal and the date that the proposal comes into effect.

The AER considers that no provision is made in the NER to cover the circumstances described by EnergyAustralia. The only occasion on which the AER could accept an application for a pass through amount for an event that occurs prior to the next regulatory control period is the occurrence of a defined event within 90 business days of 1 July 2009 (the commencement date for the next regulatory control period). Given that under the NER a DNSP is allowed 90 business days to submit an application for a pass through amount, a DNSP could delay submission of its application until the next regulatory control period.

The AER does not accept EnergyAustralia's proposed 'dead zone' event as a nominated event because it is inconsistent with the NER.

Asbestos

The DNSPs have submitted that insurance cover for asbestos is no longer offered by insurance companies. The DNSPs proposed asbestos incidents as a pass through event rather than a self insurance event because SAHA International Ltd (SAHA) considers that any estimate of a self insurance premium would be subjective with a wide range of possible values. SAHA refers to the James Hardie legal case as evidence that asbestos represents a real risk to the DNSPs.[729]

In its assessment of GasNet's proposed revisions to its access arrangement for the Victorian gas transmission system, the ACCC did not approve GasNet's proposal to treat asbestos–related claims as a pass through event.[730] The ACCC considered that allowing asbestos as a pass through event would act as a disincentive to GasNet to manage the risk. With respect to the James Hardie matter, the ACCC noted that it was the company's shareholders that bore the costs of the claims, not James Hardie's customers.

The ACCC indicated that it would consider any substantial proposal by GasNet for self insurance. The ACCC also indicated that GasNet had the option of submitting revisions to

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729 SAHA, *EnergyAustralia, Country Energy and Integral Energy Self Insurance Risk Quantification – Overview of Results*, 19 May 2008, p. 17.

730 ACCC, Final Decision, *Revised access arrangement by GasNet Australia (Operations) Pty Ltd and GasNet (NSW) Pty Ltd for the Principal Transmission System*, 30 April 2008, p. 94.

its access arrangement before the scheduled review date if claims were made against it. In that manner the ACCC could consider any proposal by GasNet on its merits at the time.[731]

The DNSPs have submitted that they have implemented measures to minimise the risk of any person contracting an asbestos disease. The main concern relates to past exposure to asbestos, before the risk became evident.

The DNSPs have submitted that allowing an asbestos pass through event would not undermine incentives to mitigate the risk. They note that they are required to adhere to occupational health and safety legislation. Damage to reputation was also submitted as a relevant factor.[732]

The AER does not consider that asbestos incidents that occurred in the past (but the full consequences of which have not yet been realised) should be passed onto current or future users. These represent contingent liabilities which the AER considers should be borne by the DNSPs' shareholders. The fact that the DNSPs may not have had measures in place in the past to manage the risk is no reason for current or future users to bear the consequences of past asbestos events. It would be no more appropriate to pass any future claims arising from past asbestos events onto users as it would be to pass on past claims that were not previously recovered from users. The regulatory framework is a forward–looking concept with the objective of adequately compensating the DNSPs for efficient costs and risks incurred over the regulatory control period.

In relation to future exposure to asbestos, the DNSPs have stated that they have implemented measures to manage risks and therefore exposure to asbestos is unlikely. Nevertheless, they consider that some residual risk remains. The AER is concerned that incentives to introduce measures, or maintain existing measures, may be undermined if asbestos claims are allowed as a pass through event. Incentives to investigate the validity of claims would be similarly undermined.

Since the DNSPs have some control over this event the AER does not consider that it meets the AER's assessment criteria. Accordingly, the AER does not accept an asbestos event as a nominated pass through event.

Gradual pollution

Country Energy and Integral Energy have proposed the gradual contamination of the environment as a pass through event.

The NSW DNSPs submitted that self insurance is not an option because the calculation of a reasonable insurance premium is not feasible.[733] Country Energy also submitted that incentives to mitigate the risk are not undermined by passing the costs through to users because it would be liable for any fines and because of the potential damage to its reputation.

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731 ACCC, Final Decision, *Revised access arrangement by GasNet Australia (Operations) Pty Ltd and GasNet (NSW) Pty Ltd for the Principal Transmission System*, 30 April 2008, p. 93.

732 SAHA, *Overview of Results*, p. 17.

733 SAHA, *Overview of Results*, p. 19.

The AER does not accept this proposed pass through event for similar reasons as noted above in relation to an asbestos event. That is, the DNSPs have some control over this event.

Sabotage

Integral Energy's definition of sabotage is similar to the definition of a bomb threat/hoax and extortion event for which SAHA has calculated a self insurance premium of $1454 per annum for Integral Energy.[734]

As mentioned earlier, if an event is insurable (either through external or self insurance) then the event should not be considered as a pass through event. Accordingly, the AER does not accept Integral Energy's proposed pass through event.

Electric and magnetic fields

Country Energy noted that if the Australian Radiation Protection and Nuclear Safety Agency (ARPANSA) draft standard were implemented, it would have significant consequences on Country Energy's operational practices and exposure to financial consequences.[735]

Integral Energy's proposed EMF pass through event covers both third party claims and changes in operational costs, whereas Country Energy is proposing changes in operational costs only be captured by this event. Country Energy informed the AER that it has insurance cover for third party claims through its liability insurance program. Integral Energy informed the AER that it has coverage for personal injury but not property.

Given that third party claims relating to EMF events are insurable, the AER does not accept third party claims as a pass through event.

In relation to any obligations placed on the DNSPs which may have a material impact on its operating costs, as noted above, the AER considers that the policy intent of the NER is that such events should be considered in the form of a regulatory change event.

Intelligent networks investments

Country Energy proposed this as a pass through event. In response to questions raised by the AER, Country Energy described these investments as consequential expenditure to the introduction of smart meters. Given the association of these investments with the introduction of smart meters the AER does not consider that a separate nominated event is necessary. Instead the AER will consider these investments as part of an application for a pass through adjustment for the introduction of smart meters as a regulatory change event.

Changes in input prices and demand

The AER does not accept the proposed changes in input and demand events on the grounds that they may act to undermine the incentive framework. A basic principle of an incentive framework is that forecasts represent best estimates and the business will bear the risk of actuals varying from forecasts. While the business will sustain the loss if

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734 SAHA, *Integral Energy Self Insurance Risk Quantification*, confidential, final report, 19 May 2008, p. 51.

735 Country Energy, *Regulatory proposal*, p. 171.

actuals fall below forecasts, similarly the business will retain the additional profit if actuals exceed forecasts. Incentives to produce robust estimates and minimise costs may be undermined if variations to normal business costs and demand are included as pass through events.

The AER has previously indicated that there may be scope for DNSPs to nominate significant input cost variations as pass through events.[736] However, because of the potential for the incentive framework to be undermined and the general nature of the proposed input costs event, the AER does not accept the pass through event as proposed. Nevertheless the AER will consider any specific events provided that the DNSP can demonstrate that the criteria set out in section 15.6.1 of this draft decision have been met.[737]

Network support payments

Network support payments are payments to generators connected to a network to provide electrical support to the network at certain times. Country Energy has sought to include network support payments as a pass through event rather than include expected payments in its forecast operating and maintenance costs.

The AER considers that it has provided a sufficient capex allowance for Country Energy to maintain and develop its network in accordance with its license obligations. Should network support be demonstrated to be the least cost solution to a network constraint within the next regulatory control period, then Country Energy would be entitled to implement this option, instead of a network alternative and retain the additional return on and of associated with the savings within the period. On this basis the AER considers that passing through network support payments would effectively result in Country Energy being overcompensated. Therefore the AER does not accept this proposed pass through event as a nominated event.

Workers compensation premiums

Country Energy is required to participate in the NSW workers compensation scheme and has proposed that any changes to its premiums be treated as a pass through event.

The AER does not accept these proposed pass through events for reasons outlined above in relation to the proposed input price changes and demand events. That is, under the incentive arrangements of the regulatory framework, the AER considers that expected costs for the next regulatory control period would be best estimates with Country Energy bearing the risk of actual costs deviating from forecasts.

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736 AER, *EBSS for ACT and NSW*, p. 13.

737 In the ACCC's assessment of GasNet's proposed revisions to its access arrangement for the Victorian gas transmission system the ACCC decided that variations to GasNet's estimates of fuel gas costs would be treated as a pass through event. In that instance volatility of gas prices made it difficult to estimate fuel gas costs. To ensure incentives to GasNet to seek the most efficient costs were not undermined GasNet was required to continue its current practice of tendering for its fuel gas needs. (ACCC, *Final Decision – Revised access arrangement by GasNet Australia (Operations) Pty Ltd for the Principal Transmission System*, 30 April 2008, p. 92.)

The AER considers allowing changes in the workers compensation premium to be included as a pass through event may undermine incentives for Country Energy to maintain and improve occupational health and safety policies and procedures.

Customer connections and joint planning events

These pass through events have been proposed by EnergyAustralia. Both relate to potential capital projects during the next regulatory control period. As the customers of the DNSPs are currently required to pay for the planning activities of the DNSPs as part of their forecast operating costs, the AER considers it would be inappropriate for their customers to also bear the risk of any deviations from forecast capital projects during the next regulatory control period. Allowing the costs to be passed through to customers would undermine incentives on the part of EnergyAustralia, either unilaterally or in conjunction with TransGrid or other DNSPs, to undertake prudent and efficient planning activities.

15.6.4 Applicability to alternative control services

EnergyAustralia has proposed that the pass through provisions of the transitional chapter 6 rules (section 6.6.1) apply to public lighting, an alternative control service, if specific pass through events occur (dead zone event, force majeure event, compliance event, and cost or demand input variance event).[738] In other words, under EnergyAustralia's proposal, should any of these pass through events occur that materially changes the costs of public lighting services, EnergyAustralia would be able to apply to the AER for a pass through.

The NER relating to pass through events refer to direct control services, which include both standard services and alternative control services. The AER considers that the NER does not preclude the pass through provisions applying to alternative control services for defined events and nominated events accepted by the AER.

15.7 AER conclusions

The AER accepts a retail project event and force majeure event as nominated pass through events for the Country Energy, EnergyAustralia and Integral Energy. For the reasons set out in this chapter the AER does not consider that the other proposed pass through events meet the AER's assessment criteria and therefore it does not accept those events as nominated pass through events.

The pass through events accepted by the AER are defined as follows:

Retail project event: Any legislative or administrative act of the NSW Government to separate the retail electricity business of a DNSP in whole or in part from the electricity distribution function of the DNSP (including by way of a sale of the DNSP's retail business), which materially changes the costs to the DNSP of providing direct control services in the next regulatory control period.

Force majeure: Any major fire, flood, earthquake, storm or other weather–related or natural disaster, act of God, riot, civil disorder, rebellion or other similar cause beyond the

[738] EnergyAustralia, *Regulatory proposal*, p. 200–201.

control of the DNSP (but excluding any insurable events – that is, those events for which external insurance or self insurance is feasible) that occurs during the next regulatory control period and materially changes the costs to the DNSP of providing direct control services.

In an application for a pass through amount in relation to these events, a DNSP must demonstrate that it has taken all reasonable measures to reduce the magnitude of the pass through amount.

15.8 AER draft decision

In accordance with clause 6.12.1(14) of the transitional chapter 6 rules the AER decides that the nominated pass through events that are to apply to Country Energy for the next regulatory control period are a retail project event and a force majeure event as defined in section 15.7 of the draft decision.

In accordance with clause 6.12.1(14) of the transitional chapter 6 rules the AER decides that the nominated pass through events that are to apply to EnergyAustralia for the next regulatory control period are a retail project event and a force majeure event as defined in section 15.7 of the draft decision.

In accordance with clause 6.12.1(14) of the transitional chapter 6 rules the AER decides that the nominated pass through events that are to apply to Integral Energy for the next regulatory control period are a retail project event and a force majeure event as defined in section 15.7 of the draft decision.

16 Building block revenue requirements

16.1 Introduction

This chapter sets out the AER's calculation of annual revenue requirements for each NSW DNSP, for the provision of standard control services for each year of the next regulatory control period. This chapter also sets out X factor values to be applied as part of the weighted average price caps (WAPC) to apply to the standard control services provided by each NSW DNSP.

16.2 Regulatory requirements

Clause 6.3.2(a) of the transitional chapter 6 rules states that the AER's building block determination must specify:

(1) the DNSP's annual revenue requirement for each regulatory year of the regulatory control period;

(2) appropriate methods for the indexation of the regulatory asset base (RAB);

(3) how any applicable efficiency benefit sharing scheme (EBSS), service target performance incentive scheme (STPIS) or demand management incentive scheme (DMIS) are to apply to the DNSP;

(4) the commencement and length of the regulatory control period;

(5) any other amounts, value or inputs on which the building block determination is based.

Clause 6.5.9 of the transitional chapter 6 rules requires a building block determination to include the X factor for each year of the regulatory control period. The AER must set the X factor with regard to the DNSP's total revenue requirement for the period. The X factor must be set to equalise (in net present value terms) the revenue to be earned from the provision of standard control services with the total revenue requirement attributable to those services. The X factor must also minimise variance between expected revenue and the annual revenue requirement for the last year of the regulatory control period.

A DNSP's building block proposal must be prepared in accordance with the AER's post tax revenue model (PTRM) and the requirements of part C and schedule 6.1 of the transitional chapter 6 rules. The building block proposal must also comply with the requirements of any relevant regulatory information instrument, such as a regulatory information notice (RIN) or regulatory information order (RIO).

Under 6.12.3(d) of the transitional chapter 6 rules the AER must approve annual revenue requirements if it is satisfied that they have been calculated using the PTRM on the basis of amounts proposed by the DNSP and accepted by the AER, or otherwise determined by the AER under part C of the transitional chapter 6 rules.

16.2.1 Annual building block revenue requirement

Clause 6.4.3(a) of the transitional chapter 6 rules defines building blocks that form the annual revenue requirement as:

- indexation of the RAB
- return on capital
- depreciation
- estimated cost of corporate income tax
- revenue increments or decrements arising from a STPIS or DMIS
- other revenue increments or decrements arising from the application of a control mechanism in the previous regulatory control period that are to be carried forward and are apportioned to the relevant year under the distribution determination for the current regulatory control period
- forecast operating expenditure (opex)
- revenue increments or decrements for that year arising from a carry forward of D–factor amounts for the last two regulatory years of the current regulatory control period, arising out of IPART's determination for that period.

16.2.2 Post–tax revenue model

The PTRM sets out how the annual revenue requirement is to be calculated and includes:

- a method that is likely to result in the best estimates of expected inflation
- the timing assumptions and associated discount rates applicable to the calculation of building blocks in clause 6.4.3 of the transitional chapter 6 rules
- the manner in which working capital is to be treated
- the manner in which the estimate corporate income tax is to be calculated.

The AER has published a transitional PTRM for NSW DNSPs[739] and a PTRM handbook.[740]

16.3 NSW DNSP proposals

16.3.1 Country Energy

Country Energy's calculation of annual revenue requirements and X factors is contained in the completed PTRM submitted as part of its regulatory proposal, and are summarised in table 16.1 below. In its PTRM, Country Energy included revenue from miscellaneous services in its expected revenues for the period.

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739 AER, *Final decision, Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–14: Post–tax revenue model*, Canberra, January 2008, Appendix B.

740 AER, *Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–14: Post–tax revenue model handbook*, Canberra, January 2008.

Country Energy proposed to deduct $70.0 million from its building block revenue requirement in 2009–10 to pass through the forecast balance of its transmission unders and overs account as at 30 June 2007.[741]

Table 16.1: Country Energy's proposed annual revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		110.9	138.6	163.7	155.0	147.6
Return on capital		413.2	479.4	547.6	619.0	696.1
Tax allowance		40.8	45.6	50.7	52.8	53.3
Operating expenditure		418.4	438.1	463.3	491.6	522.3
TUOS adjustment		–70.0	–	–	–	–
Annual revenue requirements		913.3	1101.7	1225.3	1318.4	1419.3
Expected revenues	753.2	963.9	1071.5	1191.2	1324.3	1420.2
Forecast CPI (%)		2.54	2.54	2.54	2.54	2.54
X factors[a] (%)		–23.14	–6.80	–6.80	–6.80	–3.00

Source: Country Energy, PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

Country Energy proposed an X factor of –23.14 per cent (i.e. a real increase) for the first year of the regulatory control period to account for the increase in revenue requirements between 2008–09 and 2009–10. It proposed an X factor of –6.80 per cent for years 2010–11 to 2012–13, and –3.00 per cent for 2013–14. These values result in the NPVs of the annual revenue requirements and expected revenues being equal over the regulatory control period as shown in table 16.2. The resulting difference between the annual revenue requirement and expected revenue in the final year of the period is $0.98m or 0.07 per cent. The proposed reduction of $70 million from the annual revenue requirement in 2009–10 creates a notable variation from the expected revenue in this year.

Table 16.2: Country Energy's proposed annual revenue requirements and expected revenues ($m, nominal)

	NPV	2009–10	2010–11	2011–12	2012–13	2013–14
Annual revenue requirement	4472.9	913.3	1101.7	1225.3	1318.4	1419.3
Expected revenues	4472.9	963.9	1071.5	1191.2	1324.3	1420.2
Difference (%)	0.00	5.55	–2.74	–2.78	0.45	0.07

Source: Country Energy, PTRM.

[741] Country Energy, *Regulatory proposal*, p. 176.

16.3.2 EnergyAustralia

EnergyAustralia proposed two sets of X factors—one for use in a WAPC to apply to its distribution services and another for a revenue cap on its transmission services—in conjunction with its proposal on control mechanisms for standard control services (see chapter 4 of this decision).

EnergyAustralia modified the AER's PTRM to accommodate separate building block calculations under each form of control. This involved separating assets between its transmission and distribution services and allocating opex and non-system costs to these two groups of assets, in accordance with its cost allocation method.[742] The resulting revenue requirements and X factors proposed for transmission and distribution services are summarised in tables 16.3 and 16.4 below.

EnergyAustralia included forecast revenues from miscellaneous services, monopoly services and emergency recoverable works in its expected revenues for distribution services. No adjustments as part of the building block revenue calculation were proposed for amounts arising under incentive mechanisms or forms of control mechanisms in the current regulatory control period. EnergyAustralia stated that adjustments to the annual revenue requirement may arise through approved pass through amounts.[743]

Table 16.3: EnergyAustralia's proposed annual revenue requirements and X factors – transmission ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		4.9	8.1	11.4	14.5	13.4
Return on capital		96.5	123.1	140.2	167.7	204.5
Tax allowance		3.1	7.1	8.5	10.1	11.6
Operating expenditure		39.0	40.2	43.6	45.5	47.0
Annual revenue requirements		143.5	178.5	203.7	237.8	276.4
Expected revenues	129.5	143.5	170.4	202.5	240.5	285.7
Forecast CPI (%)		2.54	2.54	2.54	2.54	2.54
X factors[a] (%)		–8.06	–15.85	–15.85	–15.85	–15.85

Source: EnergyAustralia, PTRM.
(a) Negative values for X indicate real revenue increases under the CPI–X formula.

742 EnergyAustralia, *Regulatory proposal*, p. 154.
743 EnergyAustralia, *Regulatory proposal*, p. 182.

Table 16.4: EnergyAustralia's proposed annual revenue requirements and X factors – distribution ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		71.7	95.6	116.7	138.9	134.2
Return on capital		705.3	833.3	974.8	1,135.5	1,283.4
Tax allowance		40.0	68.8	79.1	91.2	96.8
Operating expenditure		540.6	572.8	623.4	665.8	701.6
Annual revenue requirements		1357.6	1570.5	1793.9	2031.4	2216.0
Expected revenues	1021.9	1357.6	1549.2	1771.3	2011.8	2292.9
Forecast CPI (%)		2.54	2.54	2.54	2.54	2.54
X factors[a] (%)		–29.42	–10.43	–10.43	–10.43	–10.43

Source: EnergyAustralia, PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

For its distribution services, EnergyAustralia proposes X factors of –29.42 per cent (i.e. a real increase) for the first year of the regulatory control period and –10.43 per cent for each subsequent year. For transmission services, EnergyAustralia proposes X factors of –8.06 per cent for the first year of the regulatory control period and –15.85 per cent for each subsequent year. EnergyAustralia states that these values reflect the AER's convention of setting the X factors for the first year of the period to equal the annual revenue requirement in that year, with X factors in other years set equal to one another.[744]

EnergyAustralia attributes the proposed real price increase of 29.42 per cent for distribution services in 2009–10 to the following:[745]

- 18.6 per cent is due to the legacy of past regulatory periods (i.e. its current prices would be 18.6 per cent higher if they reflected its actual expenditures in the current regulatory control period rather than its regulatory allowances)
- 4.3 per cent is attributed to a higher cost of debt
- the remaining 6.5 per cent reflects planned investment and new operating costs.

EnergyAustralia notes that its X factors result in the NPVs of the revenue requirements and expected revenues for both transmission and distribution services being equal over the regulatory control period, with variances in revenues in the final years being 3.36 per cent and 3.47 per cent as shown in table 16.5.

[744] EnergyAustralia, *Regulatory proposal*, p. 151, 153.
[745] EnergyAustralia, *Regulatory proposal*, p. 11.

Table 16.5: EnergyAustralia's proposed annual revenue requirements and expected revenues ($m, nominal)

	NPV	2009–10	2010–11	2011–12	2012–13	2013–14
Transmission						
Annual revenue requirements	770.4	143.5	178.5	203.7	237.8	276.4
Expected revenues	770.4	143.5	170.4	202.5	240.5	285.7
Difference (%)	0.00	0.00	–4.51	–0.63	1.12	3.36
Distribution						
Annual revenue requirements	6688.6	1357.6	1570.5	1793.9	2031.4	2216.0
Expected revenues	6688.6	1357.6	1549.2	1771.3	2011.8	2292.9
Difference (%)	0.00	0.00	–1.36	–1.26	–0.96	3.47

Source: EnergyAustralia PTRM.

16.3.3 Integral Energy

Integral Energy's calculation of annual revenue requirements and X factors is contained in the completed PTRM submitted as part of its proposal and are summarised in table 16.6.

Table 16.6: Integral Energy's proposed annual revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		115.8	95.3	93.2	86.5	91.4
Return on capital		374.2	421.4	479.2	535.6	591.1
Tax allowance		40.9	42.2	42.5	43.4	47.5
Operating expenditure		295.2	301.4	313.9	334.1	350.2
Annual revenue requirements		826.1	860.3	928.7	999.5	1080.2
Expected revenues	656.66	805.5	867.5	936.7	1006.3	1083.5
Forecast CPI (%)		2.54	2.54	2.54	2.54	2.54
X factors[a] (%)		–18.21	–3.50	–3.50	–3.50	–3.50

Source: Integral Energy, PTRM.
(a) Negative values for X indicate real price increases under the CPI–X formula.

In its PTRM, Integral Energy has included revenue from miscellaneous and monopoly services and emergency recoverable works in its expected revenues for the regulatory control period.

Integral Energy proposes X factors of –18.21 per cent (i.e. a real increase) for the first year of the regulatory control period and –3.50 per cent for subsequent regulatory years. This results in the NPVs of the revenue requirements and expected revenues being equal over the regulatory control period as shown in table 16.7. The resulting difference between the annual revenue requirement and expected revenue in the final year of the period is $3.26 million or 0.30 per cent.

Table 16.7: Integral Energy's proposed annual revenue requirements and expected revenues ($m, nominal)

	NPV	2009–10	2010–11	2011–12	2012–13	2013–14
Annual revenue requirements	3536.2	826.1	860.3	928.7	999.6	1080.2
Expected revenues	3536.2	805.5	867.5	936.7	1006.3	1083.5
Difference (%)	0.00	–2.49	0.84	0.86	0.67	0.30

Source: Integral Energy, PTRM.

Integral Energy note that a significant proportion of the proposed price increase in 2009–10 is the result of:[746]

- changes in WACC parameters
- IPART's approach to addressing the over–recovery of revenues from the previous regulatory control period, which has resulted in prices in 2008–09 being below their cost reflective level.

16.4 Submissions

Submissions by the EMRF, EUAA and the PIAC expressed concerns about the significant increases in prices resulting from the DNSPs' proposals.

The EUAA suggested the AER be cognisant of the combined impact of increases in a variety of costs for energy users (e.g. gas, the pricing of carbon and renewable energy sources) when assessing the DNSPs' proposals.[747] The PIAC expressed a concern regarding the impact of price increases for low-income households and in the first year of the regulatory control period, and requested the AER to explore the possibility of DNSPs spreading these increases more evenly over the period.[748] The EMRF also foreshadowed that businesses unable to afford the proposed increases would either close or move offshore.[749] The EUAA and the EMRF also commented that such increases should be allocated across tariff classes in a cost reflective manner.[750]

746 Integral Energy, *Regulatory proposal*, pp. 176 and 198.
747 EUAA, p. 3.
748 PIAC, p. 3.
749 EMRF, p. 7.
750 EUAA, pp. 8–9. EMRF, p. 37.

The EMRF noted that these increases are particularly large in the context of modest increases in consumption and demand.[751] It and the EUAA noted that consumption forecasts are a key determinant for setting the price constraint, such that a forecast of low energy growth would result in a higher constraint on a per unit basis, and should therefore be closely examined by the AER.[752] The EUAA further urged the AER to ensure DNSPs minimise cross subsidies in their tariff designs through increased regulatory oversight.[753]

The EUAA also noted that EnergyAustralia and Country Energy had attributed their proposed price and revenue increases to insufficient funding of expenditure allowances in the previous IPART determination, and suggested the AER critically assess these claims and seek IPART's comments in this context.[754]

Kiama Municipal Council stated that the cost of new connections should be paid for by the development industry, new residents of businesses and State taxes, and not by existing customers.[755] Camden Council considered it unreasonable to apply the standard 'business customer' model (tariffs) to all the types of sites which Councils have an account for, including toilet blocks, club rooms, irrigation systems, fairy lights, etc.[756]

16.5 AER considerations

This section begins with a summary of the AER's consideration of issues that are common to all the DNSPs' proposals. The following sections then address each of the building blocks proposed by each DNSP. Further details on the AER's consideration of the DNSPs' proposed opex, corporate income tax and depreciation are contained in chapters 8, 9 and 10 of this decision. The return on capital using the WACC determined in chapter 11 is outlined here.

16.5.1 Common issues

Proposed price increases and X factors

As noted above, the AER must set X factors subject to the following requirements:

- they must be set with regard to each DNSPs' total revenue requirement for the next regulatory control period
- they must be set to minimise, as far as possible, the variance between the annual revenue requirement and expected revenue in the final year of the regulatory control period
- they must be set to equalise, in NPV terms, the total revenue requirement and expected revenues over the next regulatory control period under the applicable form of control.

751 EMRF, p. 6.
752 EMRF, p. 35; EUAA, p. 13.
753 EUAA, p. 9.
754 EUAA, pp. 21–22.
755 Kiama Municipal Council, p. 1.
756 Camden Council, p. 1.

Clause 6.5.9(c) also provides for different X factors to be set for each regulatory year.

Within these requirements, the AER considers there is some scope for the DNSPs and the AER to explore the possibility of reducing the impact of price shocks in the first year of the next regulatory control period. The AER does note, however, that the large proposed increases, to some extent, reflect the fact that prices for the current regulatory control period are not commensurate with the costs and expenditure being incurred by the businesses (which is addressed in the next section).

To give context to these considerations, table 16.8 below lists the real percentage increases in a typical residential customer's annual bill as a result of the proposed X factors, in the first year of the regulatory control period and the average for the subsequent four years.

Table 16.8: DNSP proposals – real increases in annual electricity bill (per cent)

	2009–10	2010–11 to 2013–14
Country Energy	9.25	2.76
EnergyAustralia (distribution)	11.77	5.22
EnergyAustralia (transmission)	0.65	1.68
Integral Energy	7.28	1.59

Note: Assumed end use bill of $1200 per year, of which 40 per cent is attributed to distribution costs and 8 per cent to transmission costs.

The AER's draft decisions on the DNSPs' X factors are listed in section 16.6 below. The corresponding impact of the AER's decision on end use customer bills is presented in table 16.9.

Table 16.9: AER draft decision – real increases in annual electricity bill (per cent)

	2009–10	2010–11 to 2013–14
Country Energy	7.88	2.72
EnergyAustralia (distribution)	9.72	5.11
EnergyAustralia (transmission)	0.26	1.61
Integral Energy	6.17	1.57

Note: Assumed end use bill of $1200 per year, of which 40 per cent is attributed to distribution costs and 8 per cent to transmission costs.

Legacy of previous regulatory decisions

The AER has conducted a high-level analysis of the impact on the X factors proposed for 2009–10 of incorporating the actual expenditures (as opposed to those forecast in IPART's and the ACCC's determinations) of each DNSP in its current revenues.

In the case of Country Energy, approximately half of the proposed X factor for 2009–10 reflects a change from the notional price/ revenue level in 2008–09 that incorporates actual expenditures for that year.[757]

For EnergyAustralia's distribution business, approximately two-thirds of its X factor for 2009–10 reflects an 'update' of prices to reflect actual expenditure levels. This is consistent with its claim (i.e. 18.6 per cent out of a proposed 29.4 per cent increase). This proportion is roughly the same for Integral Energy, which it has noted that its current prices are below their cost reflective level because of a passing back of excess revenues recovered from the prior regulatory control period.

The AER has not sought a response from IPART regarding the claims made by EnergyAustralia and Country Energy regarding the insufficiency of the allowances set in the previous determination, nor has it conducted an ex post prudency review of expenditures as this is not envisaged under the requirements of the transitional chapter 6 rules. Accordingly the AER is unable to comment on the extent to which the overspends reported by the businesses are efficient and their claims are valid. Stakeholders should note, however, that various other factors are listed as contributing to these overspends. The AER's role in this context is limited to ensuring that these contributing factors have been appropriately addressed by the DNSPs in preparing their proposals.

Tariff design

The AER agrees with stakeholders on the importance of efficiency in the design of tariffs. The NSW DNSPs have submitted indicative prices for each year of the next regulatory control period as part of their applications (RIN template 2.2.5) reflecting the requirement of clause 6.8.2(c)(4) of the transitional chapter 6 rules. They do not represent formal tariff proposals for the AER's assessment. As such there is no requirement for these indicative prices to reflect what the DNSPs actually intend to propose to the AER. Such proposals will be made to the AER once it has published its distribution determination in April 2009. For tariffs to be approved they will need to reflect the principles in clause 6.18.5 of the transitional chapter 6 rules, which include reference to the long-run marginal cost, as well as the stand alone and avoidable cost of serving customers (which are boundaries that are applied to identify cross subsidies).

While these provisions are also relevant for the recovery of new connection costs, the DNSPs are also subject to the requirements of clause 6.21.2 and 6.21.4(a) of the transitional chapter 6 rules which govern connection charges and related arrangements for particular network users.

Accuracy of pricing and forecast sales quantity inputs

The AER has examined the accuracy of the pricing inputs to the PTRM for 2008–09 in terms of whether they reflect the prices approved by IPART. This is important as they are used in the PTRM to model the starting point from which prices will be escalated under the WAPC and therefore affect the calculation of X factors. Except in minor cases, the pricing information provided by the DNSPs was accurate.

[757] That is, based on actual RAB, capex and depreciation data for 2008–09 as contained in Country Energy's roll forward model and opex for that year, Country Energy's revenue requirement would be around 12 per cent higher than the revenue it expects to earn from regulated prices in that year.

Similarly, the AER has examined the forecast energy and customer number data submitted by the DNSPs. As noted in chapter 6 of this draft decision, the AER requested updated quantity data from Integral Energy and EnergyAustralia which has been incorporated into this decision. All three DNSPs have been requested to provide further updates in February 2009 which will be incorporated into the AER's final decision and determination.

16.5.2 Country Energy

Asset base roll forward and indexation

As discussed in chapter 5, the AER has determined the opening value of Country Energy's RAB to be $4248 million as at 1 July 2009. Based on this opening value, the AER has modelled Country Energy's RAB over the next regulatory control period using the PTRM and as shown in table 16.10.

Table 16.10: AER's forecast roll–forward of Country Energy's regulatory asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	4247.5	4872.1	5538.7	6288.1	7051.7
Net capex[a]	783.1	835.7	882.2	915.5	958.7
Indexation of opening RAB	108.3	124.2	141.2	160.3	179.8
Straight-line depreciation	–266.7	–293.5	–274.0	–312.3	–351.8
Closing RAB	4872.1	5538.7	6288.1	7051.7	7838.5

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance. Note capex for 2009–10 includes $4.2 million of capitalised equity raising costs (seee section 8.6.5 of this draft decision for details).

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. Note this capex also includes capitalised equity raising costs (see section 8.6.5 for details).

Return on capital

The AER considers that Country Energy's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding regarding other inputs to the PTRM, namely the opening RAB and capex allowance determined by the AER in chapters 5 and 7 of this draft decision.

The AER has determined the annual return on capital allowance by applying the weighted average cost of capital (WACC) to Country Energy's opening RAB for each year of the next regulatory control period. This amount is outlined in table 16.18 below.

The nominal vanilla WACC of 9.72 per cent is based on a post-tax nominal return on equity of 11.34 per cent and a pre-tax nominal return on debt of 8.63 per cent. These figures are calculated using observed market data as at 21 October 2008, and will be updated closer to the AER's final decision and determination.

Depreciation

As discussed in chapter 10, the AER has not approved Country Energy's proposed depreciation schedules, and has required amendments in relation to standard asset lives and the treatment of work in progress.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the regulatory control period and to determine the depreciation allowance. Table 16.17 shows the resulting figures.

Estimated taxes payable

Using the PTRM, the AER has modelled Country Energy's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than Country Energy's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause 6.5.3, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Under the post-tax nominal framework, the application of the statutory tax rate generates an effective tax rate that can provide more appropriate and cost-reflective revenue outcomes. The effective tax rate is defined as the difference between pre-tax and post-tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Based on the approach to modelling the cash flows in the PTRM, the AER has derived an effective tax rate of 26.01 per cent for this draft decision. Table 16.11 shows the AER's estimate of Country Energy's tax payments.

Table 16.11: AER's modelling of net tax allowance ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Tax payable	92.5	99.4	87.4	101.9	111.8
Value of imputation credits	–46.2	–49.7	–43.7	–50.9	–55.9
Net tax allowance	46.2	49.7	43.7	50.9	55.9

Operating and maintenance expenditure

As discussed in chapter 8, the AER has determined a forecast opex allowance for Country Energy of $2138 million (nominal) during the next regulatory control period. Table 16.17 shows the annual opex allowance, which equates to an average amount of $428 million per annum in nominal terms.

Revenue decrements arising from previous periods' control mechanisms

The AER notes that Country Energy's expected balance of its transmission unders and overs account as at 30 June 2007, as reported to IPART, is $66 million.[758] Country Energy has not explained the derivation or source of its corresponding $70 million proposed adjustment, however it does approximate the reported value that is inflated to 2009–10 dollar terms. On this basis the AER accepts Country Energy's proposal for this building block component. As discussed below, this has implications for the relative values of the annual revenue requirements and expected revenues which are relevant considerations in the setting of X factors.

16.5.3 EnergyAustralia

As noted above EnergyAustralia's PTRM contains separate building block calculations for the purposes of creating X factors for the forms of control applying to its distribution services (WAPC) and transmission services (revenue cap). The AER has examined the amendments made by EnergyAustralia and considers the resulting calculations to be consistent with its PTRM.[759]

Asset base roll forward and indexation

As discussed in chapter 5, the AER has determined the opening value of EnergyAustralia's transmission and distribution RABs as at 1 July 2009 to be $985 million and $7203 million respectively. Based on these opening values, the AER has modelled EnergyAustralia's RABs over the next regulatory control period using the PTRM and as shown in table 16.12 and 16.13.

Table 16.12: AER's forecast roll-forward of EnergyAustralia's transmission regulatory asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	984.8	1262.0	1446.9	1726.6	2095.0
Net capex[a]	282.0	193.1	291.3	383.3	268.1
Indexation of opening RAB	25.1	32.2	36.9	44.0	53.4
Straight-line depreciation	–29.9	–40.3	–48.5	–58.9	–67.5
Closing RAB	1262.0	1446.9	1726.6	2095.0	2349.0

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. Note capex for 2009–10 includes $4.3 million of capitalised equity raising costs (see section 8.6.5 of this draft decision for details).

758 IPART, letter to the AER re: *DNSPs' transmission over and under recovery accounts for 2008/09*, 23 June 2008.

759 AER, *Final decision, Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–14: Post–tax revenue model*, Canberra, January 2008, Appendix B.

Table 16.13: AER's forecast roll-forward of EnergyAustralia's distribution regulatory asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	7202.8	8528.1	9945.9	11542.0	13003.4
Net capex[a]	1396.1	1512.0	1710.6	1597.7	1699.0
Indexation of opening RAB	183.7	217.5	253.6	294.3	331.6
Straight-line depreciation	–254.5	–311.6	–368.2	–430.6	–462.6
Closing RAB	8528.1	9945.9	11 542.0	13 003.4	14 571.3

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. Note capex for 2009–10 includes $31.4 million of capitalised equity raising costs (see section 8.6.5 of this draft decision for details).

Return on capital

The AER considers that EnergyAustralia's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding other inputs to the PTRM, namely the opening RAB and capex allowance determined by the AER in chapters 5 and 7 of this draft decision.

The AER has determined the annual return on capital allowance by applying the weighted average cost of capital (WACC) to EnergyAustralia's opening transmission and distribution RABs for each year of the next regulatory control period. This amount is outlined in tables 16.19 and 16.20 below.

The nominal vanilla WACC of 9.72 per cent is based on a post-tax nominal return on equity of 11.34 per cent and a pre-tax nominal return on debt of 8.63 per cent. These figures are calculated using observed market data as at 21 October 2008, and will be updated closer to the AER's final decision and determination.

Depreciation

As discussed in chapter 10, the AER has not approved EnergyAustralia's proposed depreciation schedules on the basis of an error in the standard life assumed for cable tunnels.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the regulatory control period and to determine the depreciation allowance. Tables 16.19 and 16.20 show the resulting allowances for EnergyAustralia's distribution and transmission networks.

Estimated taxes payable

Using the PTRM, the AER has modelled EnergyAustralia's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than EnergyAustralia's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause 6.5.3, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Under the post-tax nominal framework, the application of the statutory tax rate generates an effective tax rate that can provide more appropriate and cost-reflective revenue outcomes. The effective tax rate is defined as the difference between pre-tax and post-tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Based on the approach to modelling the cash flows in the PTRM and using inputs from this draft decision, the AER has derived effective tax rates for EnergyAustralia's distribution and transmission networks of 27.87 per cent and 24.09 per cent respectively. Tables 16.14 and 16.15 show the AER's estimate of EnergyAustralia's tax payments for distribution and transmission respectively.

Table 16.14: AER's modelling of net tax allowance – EnergyAustralia distribution ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Tax payable	72.2	128.5	147.5	169.5	179.3
Value of imputation credits	–36.1	–64.3	–73.8	–84.8	–89.6
Net tax allowance	36.1	64.3	73.8	84.8	89.6

Table 16.15: AER's modelling of net tax allowance – EnergyAustralia transmission ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Tax payable	6.1	13.7	16.1	19.3	21.1
Value of imputation credits	–3.0	–6.9	–8.0	–9.6	–10.6
Net tax allowance	3.0	6.9	8.0	9.6	10.6

Operating and maintenance expenditure

As discussed in chapter 8, the AER has determined a forecast opex allowance for EnergyAustralia's distribution and transmission networks of $2,851 million (nominal) during the next regulatory control period. Tables 16.19 and 16.20 show the annual opex allowances for distribution and transmission respectively.

16.5.4 Integral Energy

Asset base roll forward and indexation

The NER requires that the roll forward of Integral Energy's RAB, as at the end of each year of the next regulatory control period, be calculated by taking the opening RAB value, adjusting it for inflation, adding any additional capex, and subtracting disposals and depreciation for the year. The closing RAB value for one year then becomes the opening RAB value for the following year.

As discussed in chapter 5, the AER has determined the opening value of Integral Energy's RAB to be $3678 million as at 1 July 2009. Based on this opening value, the AER has modelled Integral Energy's RAB over the next regulatory control period using the PTRM, as shown in table 16.16.

Table 16.16: AER's forecast roll-forward of Integral Energy's regulated asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	3677.8	4137.9	4705.1	5260.9	5806.9
Net capex[a]	597.6	684.3	666.3	648.1	601.7
Indexation of opening RAB	93.8	105.5	120.0	134.2	148.1
Straight-line depreciation	–231.3	–222.5	–230.5	–236.4	–248.5
Closing RAB	4137.9	4705.1	5260.9	5806.9	6308.2

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. Note capex for 2009–10 includes $0.4 million of capitalised equity raising costs (see section 8.6.5 of this draft decision for details).

Return on capital

The AER considers that Integral Energy's proposed return on capital has been calculated in accordance with the PTRM, however notes that this amount has been affected by its conclusions regarding other inputs to the PTRM, namely the opening RAB and capex allowance determined by the AER in chapters 5 and 7 of this draft decision.

The AER has determined the annual return on capital allowance by applying the weighted average cost of capital (WACC) to Integral Energy's opening RAB for each year of the next regulatory control period. This amount is outlined in table 16.23 below.

The nominal vanilla WACC of 9.72 per cent is based on a post-tax nominal return on equity of 11.34 per cent and a pre-tax nominal return on debt of 8.63 per cent. These figures are calculated using observed market data as at 21 October 2008, and will be updated closer to the AER's final decision and determination.

Depreciation

As discussed in chapter 10, the AER has not approved Integral Energy's proposed depreciation schedules due to an inappropriate treatment of work in progress, which was corrected by Integral Energy.

Using a post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the regulatory control period and to determine the depreciation allowance. Table 16.22 shows the resulting figures.

Estimated taxes payable

Using the PTRM, the AER has modelled Integral Energy's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than Integral Energy's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause 6.5.3, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Under the post-tax nominal framework, the application of the statutory tax rate generates an effective tax rate that can provide more appropriate and cost-reflective revenue outcomes. The effective tax rate is defined as the difference between pre-tax and post-tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Based on the approach to modelling the cash flows in the PTRM, the AER has derived an effective tax rate of 28.05 per cent for this draft decision. Table 16.17 shows the AER's estimate of Integral Energy's tax payments.

Table 16.17: AER's modelling of net tax allowance ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Tax payable	75.7	78.2	78.6	76.8	82.5
Value of imputation credits	–37.8	–39.1	–39.3	–38.4	–41.2
Net tax allowance	37.8	39.1	39.3	38.4	41.2

Operating and maintenance expenditure

As discussed in chapter 8, the AER has determined a forecast opex allowance for Integral Energy of $1577 million (nominal) during the next regulatory control period. Table 16.22 shows the annual opex allowance, which equates to an average amount of $315 million per annum in nominal terms.

16.6 AER conclusion

The AER has calculated each DNSP's revenue requirements and X factors based on its decisions regarding the aforementioned building block components. These calculations are summarised in the following sections.

Country Energy

The AER's draft decision results in a total revenue requirement over the forthcoming regulatory control period of $5819 million, compared to $5978 million proposed by Country Energy. The main reasons for this difference reflect:

- the $196 million reduction to opex (discussed in chapter 8 of this decision)
- a $68 million increase in the regulatory depreciation building block, reflecting changes to standard life assumptions
- a $35 million reduction to the return on capital.

Table 16.18: AER conclusion on Country Energy's revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		158.4	169.2	132.7	152.0	172.0
Return on capital		412.7	473.4	538.2	611.0	685.2
Tax allowance		46.2	49.7	43.7	50.9	55.9
Operating expenditure		369.1	387.2	408.4	475.4	497.4
TUOS adjustment		–70.0	–	–	–	–
Annual revenue requirements		916.4	1079.6	1123.0	1289.3	1410.4
Expected revenues	753.2	938.8	1043.3	1159.6	1288.9	1382.2
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–19.71	–6.80	–6.80	–6.80	–3.00

Source: PTRM
(a) Negative values for X indicate real price increases under the CPI–X formula.

In deciding on Country Energy's X factors the AER notes that its proposal resulted in progressively lower real price increases over the period and a resulting (but general) alignment between its expected revenues and annual revenue requirements, which is reflected in the smaller X factor in 2013–14. The AER considers this general approach reasonable given the requirement to minimise the variance between these two values in the final year of the period.

The AER considers that there is some scope to further minimise the price shock in the first year of the regulatory control period as suggested by stakeholders and so has applied the impact of its decision as a reduction to the X factor in 2009–10.

Table 16.19: End use price impacts – Country Energy proposal and AER decision (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Country Energy proposal	9.25	3.07	3.18	3.29	1.50
AER decision	7.88	3.02	3.13	3.24	1.48

EnergyAustralia

The AER's draft decision results in total revenue requirements over the forthcoming regulatory control period of $994 million for transmission and $8453 million for distribution, compared to $1,040 million and $8,969 million respectively proposed by EnergyAustralia. The overall difference in nominal revenue requirements mainly reflects:

- a $469 million (nominal) reduction to opex
- a $54 million (nominal) reduction to the return on capital.

Table 16.20: AER conclusion on EnergyAustralia's revenue requirements and X factors – distribution ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		70.8	94.1	114.6	136.3	131.0
Return on capital		699.9	828.6	966.4	1121.5	1263.5
Tax allowance		36.1	64.3	73.8	84.8	89.6
Operating expenditure		478.1	504.5	534.7	567.0	594.0
Annual revenue requirements		1284.8	1491.5	1689.4	1909.5	2078.2
Expected revenues	1023.7	1284.8	1469.5	1670.4	1886.6	2138.0
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–24.30	–10.43	–10.43	–10.43	–10.43

Source: PTRM
(a) Negative values for X indicate real price increases under the CPI–X formula.

Table 16.21: AER conclusion on EnergyAustralia's revenue requirements and X factors – transmission ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		4.8	8.1	11.6	14.9	14.0
Return on capital		95.7	122.6	140.6	167.8	203.6
Tax allowance		3.0	6.9	8.0	9.6	10.6
Operating expenditure		32.8	33.3	34.3	35.6	36.3
Annual revenue requirements		136.3	170.9	194.6	227.9	264.5
Expected revenues	129.5	137.1	162.9	193.5	229.9	273.1
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–3.26	–15.85	–15.85	–15.85	–15.85

Source: PTRM
(a) Negative values for X indicate real revenue increases under the CPI–X formula.

EnergyAustralia's proposed X factors for 2009–10 for both transmission and distribution result in the annual revenue requirements and expected revenues being equal in the first year of the regulatory control period, which it notes is consistent with the AER's previous decisions for TNSPs. Uniform X factors are set for the remaining years which results in a slight divergence between the revenue requirements and expected revenues over the period.

In light of stakeholder comments regarding the expected price impact in 2009–10 the AER has applied its draft decision amendments in the form of a reduction in the X factor for this year, and used the X factors for the remaining years as proposed by EnergyAustralia. This has resulted in a reduction in the X factor in 2009–10 from –29.42 per cent to –24.30 per cent for distribution, and from –8.06 per cent to –3.26 per cent for transmission. The AER considers that the relative magnitude of X factors over the regulatory control period is generally appropriate with respect to minimising price shocks, as presented in table 16.22. While the resulting difference between the annual revenue requirement and expected revenues in the final year have increased from EnergyAustralia's proposal, the AER considers they have been minimised as far as is practical in the context of stakeholder concerns.

The AER's draft decision X factors for EnergyAustralia's distribution network translate into a real increase of 9.7 per cent in end users' bills in 2009–10 then approximately 5.1 per cent in each subsequent year of the next regulatory control period.

Table 16.22: End use price impacts – EnergyAustralia proposal and AER decision (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Distribution					
EnergyAustralia proposal	11.77	4.83	5.09	5.35	5.61
AER decision	9.72	4.73	4.98	5.24	5.50
Transmission					
EnergyAustralia proposal	0.65	1.36	1.56	1.78	2.02
AER decision	0.26	1.31	1.49	1.70	1.94

Integral Energy

The AER's draft decision results in a total revenue requirement over the forthcoming regulatory control period of $4632 million, compared to $4695 million proposed by Integral Energy. The main reasons for this difference reflect:

- removal of the $170 million from Integral Energy's opening RAB
- reductions to capex and opex as a result of this decision, including as the result of revised real cost escalations.

Table 16.23: AER conclusion on Integral Energy's revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		137.6	117.0	110.5	102.2	100.4
Return on capital		357.4	402.1	457.2	511.2	564.2
Tax allowance		37.8	39.1	39.3	38.4	41.2
Operating expenditure		292.2	302.6	314.8	327.7	339.5
Annual revenue requirements		825.0	860.8	921.8	979.5	1045.4
Expected revenues	661.5	792.8	856.0	925.0	996.8	1075.4
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–15.42	–3.50	–3.50	–3.50	–3.50

Source: PTRM
(a) Negative values for X indicate real price increases under the CPI–X formula.

In deciding on Integral Energy's X factors, the AER considered that X factors of –3.50 per cent for 2010–11 to 2013–14 were reasonable in the context of price shocks and were also compliant with the relevant rule requirements.

The AER has maintained this approach and, when reflective of the AER's draft decision, results in a reduction of the X factor in 2009–10 from –18.21 per cent to –15.42 per cent.

The resulting impact in terms of end use prices of the AER's decision to use these X factors, compared with Integral Energy's proposal, is outlined in table 16.24 below.

Table 16.24: End use price impacts – Integral Energy proposal and AER decision (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Integral Energy proposal	7.28	1.54	1.57	1.60	1.63
AER decision	6.17	1.52	1.55	1.58	1.61

16.7 AER draft decision

In accordance with clause 6.12.1(2)(i) of the transitional chapter 6 rules the AER refuses to approve the annual revenue requirement proposed by Country Energy.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the AER decides the X factors to apply to Country Energy are as specified in table 16.18 of the draft decision.

In accordance with clause 6.3.2(a)(1) of the transitional chapter 6 rules, the AER decides Country Energy's annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.18 of the draft decision.

In accordance with clause 6.3.2(a)(2) of the transitional chapter 6 rules, the AER decides an appropriate methodology for indexation of the regulatory asset base is as specified in section 16.5.2 of the draft decision.

In accordance with clause 6.3.2(a)(5) of the transitional chapter 6 rules, the AER decides any other amounts, values or inputs on which Country Energy's building block determination is based are as specified in section 16.5 and 16.6 of the draft decision.

In accordance with clause 6.12.1(2)(i) of the transitional chapter 6 rules the AER refuses to approve the annual revenue requirement for distribution proposed by EnergyAustralia.

In accordance with clause 6.12.1(2)(i) of the transitional chapter 6 rules the AER refuses to approve the annual revenue requirement for transmission proposed by EnergyAustralia.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the AER decides the distribution X factors to apply to EnergyAustralia are as specified in table 16.20 of the draft decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the AER decides the transmission X factors to apply to EnergyAustralia are as specified in table 16.21 of the draft decision.

In accordance with clause 6.3.2(a)(1) of the transitional chapter 6 rules, the AER decides EnergyAustralia's distribution annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.20 of the draft decision.

In accordance with clause 6.3.2(a)(1) of the transitional chapter 6 rules, the AER decides EnergyAustralia's transmission annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.21 of the draft decision.

In accordance with clause 6.3.2(a)(2) of the transitional chapter 6 rules, the AER decides an appropriate methodology for indexation of the regulatory asset base is as specified in section 16.5.3 of the draft decision.

In accordance with clause 6.3.2(a)(5) of the transitional chapter 6 rules, the AER decides any other amounts, values or inputs on which EnergyAustralia's building block determination is based are as specified in section 16.5 and 16.6 of the draft decision.

In accordance with clause 6.12.1(2)(i) of the transitional chapter 6 rules the AER refuses to approve the annual revenue requirement proposed by Integral Energy.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the AER decides the X factors to apply to Integral Energy are as specified in table 16.23 of the draft decision.

In accordance with clause 6.3.2(a)(1) of the transitional chapter 6 rules, the AER decides Integral Energy's annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.23 of the draft decision.

In accordance with clause 6.3.2(a)(2) of the transitional chapter 6 rules, the AER decides an appropriate methodology for indexation of the regulatory asset base is as specified in section 16.5.4 of the draft decision.

In accordance with clause 6.3.2(a)(5) of the transitional chapter 6 rules, the AER decides any other amounts, values or inputs on which Integral Energy's building block determination is based are as specified in section 16.5 and 16.6 of the draft decision.

17 Alternative control services

17.1 Introduction

Clause 6.2.3A(a) of the transitional chapter 6 rules classify distribution services into the following classes:

- direct control services
- negotiated distribution services
- unregulated distribution services.

The services in each class are subject to different forms of regulation. Clause 6.2.3A(b) of the transitional chapter 6 rules divides direct control services into standard control services and alternative control services. Alternative control services may be regulated using a building block determination.

This chapter sets out the AER's consideration of the NSW DNSPs' alternative control services, the control mechanism to apply to these services, and monitoring and compliance arrangements for the next regulatory control period.

17.2 Regulatory requirements

17.2.1 Current regulatory control period

17.2.1.1 IPART's 2004 determination

In its 2004 decision,[760] IPART determined that the construction and maintenance of public lighting infrastructure was an excluded distribution service and would be regulated under the Excluded Distribution Services Rule. Under the excluded distribution services rule IPART could approve or refuse to approve a DNSP's proposed prices for public lighting services based on the following requirements:[761]

- prices are to reflect the economic costs of service provision
- underlying service classifications, cost data, cost allocations and other elements that contribute to pricing decisions should be periodically reviewed and updated
- DNSPs must provide information about the service, including a description, terms and conditions, and indicative prices and rates
- when a price increase is requested, DNSPs must provide a report to IPART outlining the proposed price changes, the costs of service provision, the applicable service standards and an assessment of the customer impact of the proposed price changes.

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[760] IPART, *Final Report: NSW Electricity Distribution Pricing*, pp. 171–172.
[761] IPART, *Regulation of Excluded Distribution Services Rule 2004*, clause 2.3.

IPART indicated that it would assess a DNSP's proposed price change in light of the above requirements and if it was not satisfied that the DNSP had met them it would require the DNSP to submit an alternative proposal. IPART did not have the power to modify the DNSP's proposal under the Excluded Distribution Services Rule.

17.2.2 NER requirements

17.2.2.1 Alternative control services for NSW DNSPs

Clause 6.2.3B of the transitional chapter 6 rules prescribes which services will be classified as alternative control services. According to clause 6.2.3B(b)(1) the services classified by IPART as excluded distribution services—the construction and maintenance of public lighting infrastructure—are deemed to be classified as an alternative control service for the next regulatory control period.

A note to clause 6.2.3B(b) of the transitional chapter 6 rules states that IPART's 2004–09 distribution determination determined that the construction and maintenance of public lighting infrastructure is an excluded distribution service. IPART defined public lighting infrastructure as:[762]

> The structures, wiring, globes and other equipment:
>
> (1) used for, or associated with, the provision of public lighting to streets, roads and other public places; and
>
> (2) which are connected or attached to (or which form part of) a DNSPs distribution system (as that term is defined in the determination).

17.2.2.2 Control mechanism for alternative control services

Clause 6.2.5(c2) of the transitional chapter 6 rules sets out the form of control that the AER may apply:

> (c2) The control mechanism for alternative control services may consist of:
>
> (1) a schedule of fixed prices;
>
> (2) caps on the prices of individual services;
>
> (3) caps on the revenue to be derived from a particular combination of services;
>
> (4) tariff basket price control;
>
> (5) revenue yield control;
>
> (6) a combination of any of the above.

[762] IPART, *Regulation of Excluded Distribution Services Rule 2004*, annexure 1, pp. 103–104.

Clause 6.2.5(d) of the transitional chapter 6 rules sets out the matters the AER must have regard to in considering the appropriate control mechanism for alternative control services:

> (d) In deciding on a control mechanism for alternative control services, the AER must have regard to:
>
> (1) the potential for development of competition in the relevant market and how the control mechanism might influence that potential; and
>
> (2) the possible effects of the control mechanism on administrative costs of the AER, the Distribution Network Service Provider and users or potential users; and
>
> (3) the regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination; and
>
> (4) the desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction); and
>
> (5) any other relevant factor.

17.2.3 AER statement of approach

Clause 6.2.5(e) of the transitional chapter 6 rules provides:

> The AER must, before 1 March 2008 or the date that is one month after the commencement date (whichever is the later), publish a statement indicating its likely approach to the control mechanisms for alternative control services. In preparing the statement, the AER may carry out such consultation as the AER thinks appropriate and may take into consideration any consultation carried out before the commencement date

In its statement indicating the likely approach to the control mechanism for alternative control services (statement on alternative control services), the AER proposed to apply the following form of control to public lighting services over the next regulatory control period:[763]

- a schedule of fixed prices in the first year of the regulatory control period
- a price path (such as CPI–X) for the remaining years of the regulatory control period.

The AER proposed to determine the initial price levels and the price path with reference to the efficient costs of providing public lighting services. The statement on alternative control services indicated that a limited building block analysis would be employed to assess the efficiency of the prices.[764]

The AER is able to make amendments to its likely approach to the control mechanism for alternative control services at the distribution determination. However, if the AER does

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[763] AER, *Statement on control mechanisms for alternative control services for the ACT and NSW 2009 distribution determination*, February 2008, pp. 4–5.
[764] AER, *Control mechanisms for alternative control services ACT and NSW*, pp. 4–5.

make any amendments to the control mechanism for alternative control services it is required to provide its reasons for doing so.[765]

17.2.4 Other relevant regulation – NSW Public Lighting Code

In January 2006, the NSW Department of Energy, Utilities and Sustainability (DEUS) (now the NSW Department of Water and Energy) introduced a voluntary code of practice for a range of public lighting services in NSW (the Public Lighting Code). While the AER notes there have been issues surrounding the Public Lighting Code, its purpose is to clarify the relationship between public lighting service providers and customers, and to that end sets out some benchmarks to assist customers.

17.3 NSW DNSP proposals

17.3.1 NSW DNSPs' current tariff structure

Country Energy

Country Energy stated its tariffs for the provision of public lighting services are currently structured a number of different ways, depending on whether the:[766]

- construction and maintenance of the public lighting installation is provided by Country Energy or the customer
- customer or Country Energy is responsible for funding the asset's replacement at the end of its useful life
- lights are metered.

Country Energy's current tariff structure for public lighting services is set out in table 17.1.

Where a customer chooses to replace one component of a public lighting installation before the end of its useful life, Country Energy requires the customer to reimburse it for the unrecovered depreciated capital value of the assets removed, based on an amount equal to half the total replacement value. Reimbursement of unrecovered capital is only applicable where a customer chooses to replace an existing light funded by Country Energy before the end of its useful life.[767]

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[765] AER, *Control mechanisms for alternative control services ACT and NSW*, p. 7.

[766] Country Energy, *Regulatory proposal*, p. 195.

[767] Country Energy, *Regulatory proposal*, p. 196.

Table 17.1: Country Energy's current tariff structure for public lighting services

Tariff	Description
Rate 1 (obsolete)	Country Energy is responsible for capital provision, maintenance and replacement.
Rate 2	Customer provides the capital and Country Energy is responsible for maintenance and replacement.
Rate 3	Customer is responsible for capital provision, maintenance and replacement.
Rate 4 (obsolete)	Country Energy is responsible for capital provision, maintenance and replacement
Rate 5 (obsolete)	Country Energy is responsible for capital provision and replacement and the customer is responsible for maintenance.
Rate 6	Country Energy provides the capital and the customer is responsible for maintenance and replacement.
Rate 7	Applies where one component of the public lighting asset is replaced before the end of its useful life. Country Energy is responsible for capital provision, maintenance and replacement.
Rate 8	Customer is responsible for capital provision and replacement and Country Energy is responsible for maintenance.

Source: Country Energy, *Regulatory proposal*, p. 196.

Country Energy clarified that for rate 2 the customer provides the capital and is responsible for replacement, while Country Energy is responsible for maintenance. Country Energy also clarified that rate 7 only applies where an existing light is replaced before the end of its useful life.[768]

EnergyAustralia

EnergyAustralia currently provides public lighting services under a number of different approaches, represented by different tariffs for individual components.[769] Its current tariff structure for public lighting services is set out in table 17.2 below.

Table 17.2: EnergyAustralia's current tariff structure for public lighting services

Tariff	Description
Rate 1	Applies where EnergyAustralia has invested the capital to provide the component. Includes annualised capital charge and applicable operating costs.
Rate 2	Applies where the customer has invested the capital to provide the component. Includes only operating costs.
Rate 3	Applies where the customer has funded the capital investment and also undertakes the maintenance. This rate is set at zero.

Source: EnergyAustralia, *Regulatory proposal*, pp. 193–194.

768 Country Energy, *email to AER,* 27 November 2008.
769 EnergyAustralia, *Regulatory proposal*, pp. 193–194.

EnergyAustralia has proposed to provide services under a new rate 4 tariff during the next regulatory control period. Rate 4 relates to the situation where a customer chooses to retrofit a component (for which the customer was previously charged under rate 1) before the end of its useful life. Where a customer chooses to retrofit a component before the end of its useful life, under EnergyAustralia's rate 4 tariff, the customer will be required to compensate it for the stranded cost of the component being replaced.[770]

Integral Energy

Integral Energy provides public lighting services under two types of tariff, namely schedule 1 and schedule 2. The difference between the two tariffs relates to the funding of the initial capital cost and the responsibility for ongoing maintenance and replacement of the public lighting assets.[771] Integral Energy's current tariff structure for public lighting services is set out in table 17.3 below.

Table 17.3: Integral Energy's current tariff structure for public lighting services

Tariff	Description
Schedule 1	Integral Energy provides the capital funding up to a pre-determined limit for each type of public lighting asset and also funds all operating costs relating to the service.
Schedule 2	Developer or customer funds the capital costs of installation and Integral Energy provides maintenance and replacement of the equipment.

Source: Integral Energy, *Regulatory proposal*, p. 210.

17.3.2 Control mechanism

Country Energy,[772] EnergyAustralia[773] and Integral Energy[774] have all proposed a schedule of fixed prices for the first year and a proposed price path for the remaining years of the next regulatory control period as contemplated under the AER's statement on alternative control services.

Country Energy proposed to adjust prices annually in line with inflation and escalation rates based on real increases in wages for the electricity, gas and water sector (EGW).[775]

EnergyAustralia proposed a CPI + 1.9 per cent price path on average for public lighting prices; this is based on escalation for real increases in EGW wages.[776]

Integral Energy proposed an average price path that is adjusted in real terms by X factors based on a scenario with a higher initial year pricing increase (P_0) and constant real increases for the remaining four years of the regulatory control period.[777]

770 EnergyAustralia, *Regulatory proposal*, p. 194.
771 Integral Energy, *Regulatory proposal*, p. 210.
772 Country Energy, *Regulatory proposal*, p. 194.
773 EnergyAustralia, *Regulatory proposal*, p. 190.
774 Integral Energy, *Regulatory proposal*, p. 205.
775 Country Energy, *Regulatory proposal*, p. 206.
776 EnergyAustralia, *Regulatory proposal*, p. 193.
777 Integral Energy, *Regulatory proposal*, p. 206.

The NSW DNSPs stated that they are attempting to bring public lighting prices to a cost reflective position.[778] In its statement on alternative control services, the AER proposed to determine the initial price levels and the price path for public lighting with reference to the efficient costs of providing the service.[779]

17.3.3 Regulatory asset base

The AER's statement on alternative control services sets out that the NSW DNSPs may base the opening valuation of their respective RABs on the value derived from IPART's previous determination, with any efficient adjustments for capex and depreciation.[780] In IPART's previous determination, public lighting was reclassified from a prescribed service to an excluded service.[781] Therefore, in its statement on alternative control services the AER proposed that the asset valuation for public lighting should be derived by deducting the opening RAB from the current regulatory control period (which only included prescribed services) from the closing RAB from the 1999–04 regulatory control period (which included both prescribed and public lighting services) (the AER's formula).[782]

As set out at table 17.4, using the AER's formula the NSW DNSPs have provided the following opening asset bases for alternative control services as at 1 July 2009.

Table 17.4: Opening RABs as at 1 July 2009 ($m, nominal)

DNSP	RAB
Country Energy	15.0
EnergyAustralia	139.2
Integral Energy	37.3

Sources: Country Energy, *Regulatory proposal*, p. 202, table 11.3;
EnergyAustralia, *Regulatory proposal*, p. 198, table 7.2;
Integral Energy, *Regulatory proposal*, p. 221, table 19.7.

While all the NSW DNSPs have complied with clause 6.8.2(c)(3A)(i) of the transitional chapter 6 rules to provide a demonstration of the AER's approach to regulating alternative control services, EnergyAustralia and Country Energy have also proposed a different method for calculating their opening RABs. Both EnergyAustralia and Country Energy stated that it was not appropriate to roll forward the IPART determined RAB, choosing instead to adopt an optimised depreciated replacement cost (ODRC) asset valuation.

Country Energy

Country Energy has not applied an asset valuation for the composite asset base in determining prices. Rather it applied a 'half life' based price cap approach that allows

778 Integral Energy, *Regulatory proposal*, p. 207; Country Energy, *Regulatory proposal*, p. 197; EnergyAustralia, *Regulatory proposal*, p. 193.

779 AER, *Control mechanisms for alternative control services ACT and NSW*, p. 5.

780 AER, *Control mechanisms for alternative control services ACT and NSW*, p. 5.

781 IPART, *Final report: NSW Electricity Distribution Pricing,* p. 12.

782 AER, *Control mechanisms for alternative control services ACT and NSW*, p. 5.

tariffs to remain level each year without having to calculate different tariffs for each asset's age.[783] In complying with its regulatory information notice (RIN), Country Energy provided an estimate of its opening asset base ($12 million in 2004) using the AER's formula. However, Country Energy considered this figure to be 'fraught with uncertainty' and that any roll forward of this value is problematic.[784] Country Energy did not support a public lighting price determination that relies on IPART's notional asset valuation as it does not allow for cost reflectivity and IPART's Excluded Services Distribution Rule did not allow for determination of a capital base.[785] Country Energy stated that IPART's determination does not provide an indication of the expected rate of depreciation of a RAB relating to the public lighting system.[786]

Therefore, Country Energy proposed cost reflective prices based on an ODRC asset valuation of the current replacement cost of the public lighting assets.[787] Country Energy considers that the total replacement value of the public lighting assets it has funded is $58 million, assuming straight line depreciation and that assets are half-way through their useful life, it proposed that the ODRC value of public lighting is approximately $29 million. Country Energy also proposes a rebate mechanism to transition customers to cost reflective levels over time.[788]

EnergyAustralia

EnergyAustralia proposed an annuity approach to calculate the cost of service provision. It stated this will determine cost reflective prices.[789] EnergyAustralia also proposed a rebate mechanism to mitigate any price shocks that may arise in the transition to cost reflective prices.[790] It stated that its proposed approach is likely to recover less net revenue from customers than the RAB roll forward model.

EnergyAustralia submitted that IPART's removal of $98 million ($2003–04) from the prescribed services asset base was not supported by the necessary financial data, particularly as it did not include a determination on the asset valuation over time; depreciation rates; or the level of opex.[791] It suggested that this lack of data means that there is no clear link between IPART's RAB value and the 2004–09 prices and therefore, 'there is no economic rationale to calculate the public lighting RAB at 1 July 2009 by rolling forward IPART's adjustment'.[792]

EnergyAustralia argued that the AER's likely approach is inappropriate as it does not provide any clear signals of the economic costs of providing the service; fails to allow recovery of costs that span more than one regulatory control period; and does not give effect to existing capex incentives.[793] However, in order to comply with the AER's RIN,

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783 Country Energy, *Regulatory proposal*, p. 203.
784 Country Energy, *Regulatory proposal*, p. 201.
785 Country Energy, *Regulatory proposal*, p. 200.
786 Country Energy, *Regulatory proposal*, p. 201.
787 Country Energy, *Regulatory proposal*, p. 202.
788 Country Energy, *Regulatory proposal*, p. 199.
789 EnergyAustralia, *Regulatory proposal*, p. 196.
790 EnergyAustralia, *Regulatory proposal*, p. 195.
791 EnergyAustralia, *Regulatory proposal*, p. 198.
792 EnergyAustralia, Regulatory proposal, p. 198.
793 EnergyAustralia, *Regulatory proposal*, p. 198.

EnergyAustralia suggested that, if the AER's roll forward approach is used, its opening RAB value would be $139 million.

Instead, EnergyAustralia proposed cost reflective prices based on an ODRC asset valuation of the current replacement cost of providing the public lighting service. The total replacement value of EnergyAustralia's public lighting assets is $258 million as at March 2008, assuming straight line depreciation and that assets are half-way through their useful lives, EnergyAustralia proposed that the ODRC value of public lighting is approximately $129 million. EnergyAustralia suggested that its proposal is 'reasonable' because the AER's likely approach results in a larger RAB, therefore, its own approach will not result in greater prices.[794] EnergyAustralia estimated that its method would recover less revenue from customers than the AER's roll forward model.[795]

Integral Energy

Integral Energy stated that it has rolled forward its RAB for its alternative control services consistent with the roll forward methodology accepted by IPART in its 2008 public lighting decision. Integral Energy proposed that the RAB value of public lighting at 1 July 2009 is $37 million.[796]

17.3.4 Return on capital

All NSW DNSPs proposed to use the same WACC parameters as applied to standard control services.[797] It is noted that EnergyAustralia did not propose a return on capital but rather an annuity payment which consists of a return on capital and a return of capital.

17.3.5 Depreciation

Country Energy and Integral Energy proposed to use straight line depreciation assuming a life of 20 years and that the assets are half way through their useful life.[798] Integral Energy stated that this was consistent with IPART's previous determinations.[799] EnergyAustralia did not propose straight line depreciation based on an assumption that assets were halfway through a 20 year life. Instead it proposed an annuity method calculated over a 20 year asset life. This method did not require a remaining life assumption. EnergyAustralia's proposed depreciation was implicit in the annuity calculation.

The AER's statement on alternative control services indicates that it would accept present depreciation assumptions.[800]

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794 EnergyAustralia, *Regulatory proposal*, p. 199.

795 EnergyAustralia, *Regulatory proposal*, p. 199.

796 Integral Energy, *Regulatory proposal*, p. 221.

797 EnergyAustralia, *Regulatory proposal*, p. 194; Integral Energy, *Regulatory proposal*, p. 206; Country Energy, *Regulatory proposal*, p. 197.

798 EnergyAustralia, *Regulatory proposal*, pp. 192, 199; Integral Energy, *Regulatory proposal*, p. 222; Country Energy, *Regulatory proposal*, p. 198.

799 Integral Energy, *Regulatory proposal*, p. 222; Country Energy, *Regulatory proposal*, p. 187.

800 AER, *Control mechanisms for alternative control services ACT and NSW*, p. 5.

17.3.6 Capex

Country Energy stated that capex does not drive changes in the prices for public lighting services as these are driven by the current cost of providing the service, and the 'half life' approach to pricing.[801]

EnergyAustralia stated that the forecast capex for the next regulatory control period includes the deployment of energy efficient lights to replace less reliable (as considered by EnergyAustralia) residential road lights. It noted capex forecasts are not used in the calculation of public lighting prices for the next regulatory control period. EnergyAustralia's proposed prices are based on the current levels of inventory in service. This means that forecast levels of annual capital and operating expenditure are not relevant to the price cap moving forward. However, under a price cap form of control, the total revenue will track the level of demand for the services.[802]

Integral Energy indicated that capex increases for the next regulatory control period are due to:[803]

- real increases in input costs
- an increase in expenditures for the replacement of steel columns and luminaires.

The forecast capex for alternative control services for the NSW DNSPs for the next regulatory control period is set out at Table 17.5.

Table 17.5: NSW DNSPs' forecast capex for 2009–14 ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	1.9	1.9	2.0	2.1	2.1	10.0
EnergyAustralia	16.9	16.6	16.5	16.5	16.5	82.9
Integral Energy	5.3	5.3	5.3	5.4	5.5	26.8

Source: Country Energy, *Regulatory proposal*, p. 206; EnergyAustralia, *Regulatory proposal,* Attachment 7.2, p. 3; Integral Energy, *Regulatory proposal*, p. 218.

17.3.7 Opex

Country Energy stated that the step change in opex from 2007–08 ($8.8 million) to 2008–09 ($13 million) is attributable to the commencement of the bulk replacement program, approximately 48 000 lamps are to be changed at an extra cost of $3 million.[804]

EnergyAustralia's forecast opex includes maintenance programs such as 'standard' bulk lamp replacement, regular spot repairs, night patrols on main traffic route lights to maintain efficiency levels and increased resources to shorten repair times in local government areas. It also includes an annual escalation of 1.9 per cent to provide for real

[801] Country Energy, *Regulatory proposal*, p. 205.
[802] EnergyAustralia, *Regulatory proposal*, p. 196.
[803] Integral Energy, *Regulatory proposal*, p. 206.
[804] Country Energy, *Regulatory proposal*, p. 206.

increases in labour costs.[805] EnergyAustralia stated that as the vast majority of public lighting opex is labour driven, it proposed to escalate public lighting prices by the real increase in EGW wages.[806]

Integral Energy stated that its public lighting opex is subject to a number of cost drivers. It claimed that opex increases for the next regulatory control period are due to:[807]

- the inclusion of corporate overheads[808]
- the annual increase of 2.2 per cent in the number of public lighting assets requiring inspection, operating and maintenance
- real increases in labour cost inputs over the regulatory period.

The forecast opex for alternative control services for the NSW DNSPs for the next regulatory control period is set out at Table 17.6.

Table 17.6: NSW DNSPs' forecast opex for 2009–14 ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	13.0	12.6	12.6	13.3	14.0	65.5
EnergyAustralia	14.4	14.7	15.0	15.3	15.6	74.8
Integral Energy	9.8	9.5	9.7	9.7	9.8	48.5

Source: Country Energy, *email to AER*, 21 July 2008; EnergyAustralia, *Regulatory proposal*, Pro forma 2.2.2 Table 4; Integral Energy, PTRM for alternative control services.

17.3.8 Revenue requirement

Integral Energy was the only NSW DNSP to apply a limited building block approach in developing its schedule of charges and therefore it is the only NSW DNSP which has developed its forecast revenue requirements (table 17.7). Country Energy and EnergyAustralia have developed their schedule of charges based on cost to serve models that do not rely on a regulated asset base, forecast opex or forecast capex.

Table 17.7: Forecast unsmoothed revenue requirement for 2009–14 ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Integral Energy	18.0	18.5	19.5	20.3	22.4	98.6

Source: Integral Energy, *Regulatory proposal*, p. 223.

805 EnergyAustralia, *Regulatory proposal*, p. 193.
806 EnergyAustralia, *Regulatory proposal*, p. 193.
807 Integral Energy, *Regulatory proposal*, p. 220.
808 IPART in its February 2008 reasons for decision regarding Integral Energy's December 2007 revised application for public lighting price increases stated that '[a]ny proposal for a reallocation of corporate overheads between prescribed services and public lighting should be held over until the next Determination of prescribed services (or their equivalent) to avoid the possibility of double counting'. See IPART, *Statement of Reasons for Decision, Matter: Integral Energy's revised application of 21 December 2007 for price increases for the construction, maintenance and asset management components of its public lighting business*, 27 February 2008, p. 4.

17.3.9 Pass through

EnergyAustralia proposed pass through events for alternative control services. The AER's assessment of these proposed pass through events is in chapter 15.

17.4 Submissions

The AER received a large number of submissions on alternative control services, in particular from councils and regional organisations of councils. Parties from whom the AER received submissions are listed in appendix U of this draft decision. The AER also received submissions from several NSW councils (collectively referred to as 'the Other NSW Councils') which all raised very similar issues. The NSW councils comprising the Other NSW Councils are also listed in appendix U. Where the submissions from the Other NSW Councils are referred to in the text, the AER is referring to any and all of the individual submissions. The AER has published all submissions received on its website.

On 30 July 2008 the AER held a public forum for interested parties on the regulatory proposals submitted by the NSW DNSPs. Public lighting was one of the matters discussed at the public forum. EnergyAustralia made a written submission to the AER responding to comments made in relation to public lighting. On 30 October 2008 EnergyAustralia made a further written submission to the AER entitled 'Response to submissions on EnergyAustralia's public lighting proposal'.

The sections below set out the main issues raised in submissions.

17.4.1 Efficiency of costs underlying proposed prices

The Other NSW Councils stated there is significant concern that EnergyAustralia's cost of service for public lighting is high and not supported by a robust demonstration of costs.[809] These councils and the Bankstown City Council[810] stated that there are large and unsupported component price movements in EnergyAustralia's proposal (for example, EnergyAustralia's new energy efficient lighting).

EnergyAustralia submitted that its prices for the next regulatory control period are based on the efficient costs of providing public lighting services. It also stated that price increases are driven by public lighting customers' push for expensive energy efficient lighting and a significant reduction in subsidies—which meant public lighting customers were not charged cost reflective prices in the past.[811] EnergyAustralia further submitted that the benefits of energy efficient lights accrue to public lighting customers and it is therefore appropriate that public lighting customers pay the costs of these energy efficient lights.[812]

Parramatta City Council,[813] Baulkham Hills City Council[814] and WSROC[815] stated that the Integral Energy proposal does not go into sufficient detail to demonstrate how it

809 See for example Hunter's Hill Council's response to the AER's request for submissions on NSW DNSPs' regulatory proposals, 5 August 2008, p.1
810 Bankstown City Council, p. 4.
811 EnergyAustralia, *Supplementary response,* p. 4.
812 EnergyAustralia, *Supplementary response*, p. 5.
813 Parramatta City Council, p. 2.
814 Baulkham Hills City Council, p. 2.

arrived at the proposed price changes. Parramatta and Baulkham Hills City Councils sought full disclosure of the underlying pricing models with detailed cost assumptions on aspects including labour, cost components, cost allocations, calculation methods, inventory, asset replacement and maintenance policies and assumptions on asset age.

REROC submitted that Country Energy's proposals are not adequately supported by data and analysis and, if approved by the AER, could result in material subsidies from councils to Country Energy, inefficiencies and a reduction in public welfare.[816] It also stated that Country Energy's bulk lamp replacement costs do not appear to be generating any real savings against its spot replacement program. REROC submitted that Country Energy's bulk lamp replacement cost therefore warrants careful consideration, analysis and benchmarking.[817]

Parramatta City Council,[818] Baulkham Hills City Council,[819] Bankstown City Council,[820] SSROC[821] and REROC[822] recommended that the AER engage in benchmarking prices against other regulated network service providers in NSW and the NEM and against the public price review conducted by the Victorian Essential Services Commission (ESCV).

EnergyAustralia noted that it had filed an extensive report to IPART on the difficulties of benchmarking public lighting prices between NSW and Victoria. It submitted that the ESCV classified public lighting as an excluded service on a prospective basis and that public lighting prices in Victoria would not be comparable with NSW until all 'pre 2001' equipment was retired in Victoria, which could be up to 35 years from 2001.[823] EnergyAustralia further submitted that it has sought regulatory approval of prices that allow for the reasonable costs of public lighting service provision as proposed by the NER and therefore the AER must review the costs proposed by EnergyAustralia that underline its proposal, rather than compare prices with other service providers who may have a different pricing philosophy.[824]

In relation to EnergyAustralia's regulatory proposal, SSROC submitted while there are references to lighting assets generally having an asset life of 20 years, there does not appear to be acknowledgement of the longer asset lives of poles and brackets. SROC cited ESCV's findings that poles and brackets should have asset lives of 35 years.[825]

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815 WSROC, *Submission to the AER Distribution Determination of NSW DNSPs for the period 2009–2014*, August 2008.

816 REROC, p. 2.

817 REROC, p. 5.

818 Parramatta City Council, *Response to AER's request for submissions on NSW DNSPs' regulatory proposals*, 4 August 2008, p. 2.

819 Baulkham Hills City Council, *Response to AER's request for submissions on NSW DNSPs' regulatory proposals*, 8 August 2008, p. 2.

820 Bankstown City Council, *Response to AER's request for submissions on NSW DNSPs' regulatory proposals*, 8 August 2008, p. 3.

821 SSROC, *Submission on EnergyAustralia's public lighting proposal for 2009–2014*, 8 August 2008, p. 3.

822 REROC, *Response to AER's request for submissions on NSW DNSPs' regulatory proposals*, 8 August 2008, p. 3.

823 EnergyAustralia, *Supplementary response to AER's request for submissions on NSW DNSP's regulatory proposals*, 30 October 2008, p. 6.

824 EnergyAustralia, *Supplementary response*, p. 6.

825 SSROC, p. 5.

17.4.2 EnergyAustralia approach to retrofitting

SSROC stated that where a customer has chosen to have EnergyAustralia retrofit a component before the end of its useful life, in addition to the published Rate 4 tariff, the customer will be required to reimburse EnergyAustralia for the stranded cost of the component being replaced calculated at half the replacement value. SSROC stated that EnergyAustralia's approach to retrofitting needs careful consideration because:[826]

- it is unclear why, having paid out undepreciated capital on an existing asset, there would be a basis for a 'Rate 4' tariff at a premium to Rate 1
- it is unclear whether this premium would apply in perpetuity and, if so, on what basis
- it would be inappropriate for a customer to be required to reimburse the stranded costs of the component being replaced based on an arbitrary assumed age of half the asset life. The real age of the asset should be used to calculate the stranded cost
- it would be inappropriate for a customer to be required to reimburse the stranded cost of the component being replaced at half the replacement value. The appropriate reimbursement should be the depreciated value of the original installation cost because the current replacement value may exceed the initial installation cost.

17.4.3 Past technology selections

SSROC stated that EnergyAustralia continued to install TF2*20 lighting for at least 15 years beyond the time at which it was recognised by other utilities to have become technically obsolete. SSROC submitted that in 2009 EnergyAustralia is proposing a 78 per cent first year increase in the SLUOS costs for TF2*20 lighting and questioned why councils should bear full responsibility for lighting assets that were obsolete when they were installed, creating a costly, poorly performing legacy.[827] SSROC submitted that where EnergyAustralia has made inappropriate technology choices, given inappropriate advice to councils or continued practices in the field that EnergyAustralia management had agreed to halt, there needs to be financial consequences for EnergyAustralia or clear recourse for councils.[828]

EnergyAustralia stated that its approach has been to evaluate and install luminaires that would avoid a maintenance regime that would increase cost of service to public lighting customers and decrease the effectiveness of public lighting to the community.[829] EnergyAustralia submitted that it required that a trial of the T5 (MK 1) luminaires take place before it would commit to large scale replacement of the TF2*20 luminaires with T5 lighting.[830] After a two year trial of the T5 (MK1) luminaires, the results were provided to the manufacturers who subsequently introduced a new version of the T5 (T5 (MK3)). EnergyAustralia stated that in 2007 it commenced a second trial to evaluate the T5 (MK3) luminaires and another energy efficient luminaire, the compact fluorescent lamp (CFL). EnergyAustralia submitted that in late 2007 it determined that

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826 SSROC, pp. 5–6.
827 SSROC, p. 6.
828 SSROC, p. 7.
829 EnergyAustralia, *Supplementary response*, p. 11.
830 EnergyAustralia, *Supplementary response*, p. 12.

both the T5 (MK3) and CFL luminaires were suitable substitutes for existing residential luminaires and informed its public lighting customers of the proposed prices for both luminaires.[831]

17.4.4 The annuity method

SSROC submitted that EnergyAustralia's annuity based financial calculations approach is an inappropriate and costly change in approach. SSROC noted that there appears to be no comparable precedent within the Australian electricity sector for EnergyAustralia's annuity approach. SSROC stated that during the 2004–2005 pricing reset, EnergyAustralia made a similar proposal which was not supported by IPART and was subsequently withdrawn by EnergyAustralia.[832] In its supplementary submission, SSROC stated that EnergyAustralia's annuity based calculations appear to overstate costs by about 18 per cent compared to a return on and of capital approach.[833]

EnergyAustralia submitted that the annuity method accurately prices components using widely accepted 'time value of money' financial principles. It stated that the annuity method generates 20 equal annual payments that correspond to the upfront capital cost incurred by EnergyAustralia when installing components.[834]

17.4.5 Service levels

The Other NSW Councils submitted that there cannot be confidence in pricing decisions unless there is clarity about the application of the price.[835]

REROC submitted that Country Energy's proposed changes to Tariff 2 will result in significant price increases to councils without any corresponding lift in service levels.[836] It also submitted that Country Energy should perform a detailed assessment of the market supply of competitive operating and maintenance services for public lighting in rural and regional areas to determine if an effective market exists before requiring councils to source asset replacement services.[837]

EnergyAustralia submitted that its proposal was developed to meet the NER requirements and did not envisage significant change from the existing regulatory regime. It acknowledges that there is some scope to improve the regulatory framework that currently applies to public lighting, however it considers that it would be inappropriate to make significant changes to the existing regime without full public consultation, commencing with an AER statement of approach. EnergyAustralia submits that such a review should occur at a national level and could not be realistically completed within the time allowed for this review.[838]

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831 EnergyAustralia, *Supplementary response*, p. 11.
832 SSROC, p. 5.
833 SSROC, p. 2.
834 EnergyAustralia, *Supplementary response*, p. 9.
835 For example: Hunter's Hill Council, p. 2.
836 REROC, *Response to AER's request for submissions on NSW DNSPs' regulatory proposals*, 8 August 2008, p. 6.
837 REROC, p. 7.
838 EnergyAustralia, *Supplementary response*, p. 10.

SSROC submitted that the reliability figures established by EnergyAustralia's staff report (attached to SSROC's supplementary submission) are inconsistent with EnergyAustralia's proposed annual maintenance charges for the luminaires.[839]

17.4.6 Public Lighting Code

WSROC noted the concerns of its member councils relating to slow response times to complaints and faults.[840] Parramatta City Council[841] and Baulkham Hills City Council[842] submitted that not one reported fault has been corrected by Integral Energy within the specified 8 day period for repairs under the Public Lighting Code. Further, Integral Energy is required to submit quotations for new work within 30 days of provision of the design brief by the customer, but at present no such work is being undertaken by Integral Energy within the specified 30 day period. WSROC stated that the AER should consider and, if necessary, investigate the complaints made by councils. WSROC also submitted that the AER should ensure effective mechanisms to resolve equipment failures are implemented which will provide real incentives to the NSW DNSPs to meet service commitments.[843]

Campbelltown City Council stated that the AER should consider the need to review the Public Lighting Code and its service obligations, to identify a more sustainable level of service for public lighting.[844] Liverpool City Council agreed with this submission.[845]

17.4.7 Lack of information disclosure

The Other NSW Councils, Parramatta City Council,[846] Bankstown City Council,[847] Baulkham Hills City Council[848] and SSROC[849] submitted that while councils note that the AER is bound to make its determination within certain timeframes, they consider that it is unreasonable to expect meaningful representation from councils without full information disclosure within a reasonable time. The Other NSW Councils stated that EnergyAustralia's cost-to-serve model was not provided before the time to make submissions closed.[850]

Camden Council submitted that the information in Integral Energy's regulatory proposal concerning the cost implications associated with public lighting was confidential which prevented Camden Council from being able to understand and plan for potentially significant cost increases.[851]

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839 SSROC, p. 3.

840 WSROC.

841 Parramatta City Council, p. 1.

842 Baulkham Hills City Council, p. 1.

843 WSROC, p. 2.

844 Campbelltown City Council, *Response to AER's request for submissions on NSW DNSPs' regulatory proposals*, 8 August 2008, p. 3.

845 Liverpool City Council, *Response to AER's request for submissions on NSW DNSPs' regulatory proposals*, 2 October 2008.

846 Parramatta City Council, p. 4.

847 Bankstown City Council, p. 1.

848 Baulkham Hills City Council, p. 3.

849 SSROC, p. 1.

850 For example: Hunter's Hill Council, p.1.

851 Camden Council, *Response to AER's request for submissions on NSW DNSPs' regulatory proposals*, 5 August 2008, p. 1.

SSROC stated that EnergyAustralia has provided total capex for each capital item but has failed to show how this capital cost was derived. Further, information that EnergyAustralia provided for the last determination has not been provided this time, including the breakdown of installation labour allocations between brackets and luminaires, total assumed installation times and spot repair times, assumed spot replacement rates per annum by component, total labour costs per hour for a two person crew, assumed traffic control costs and assumed component capital costs.[852]

EnergyAustralia submitted that it had participated in the AER's consultation process and provided all information that it has been requested to provide. It also stated that it had provided specific information for public lighting customers (via the AER) of the proposed public lighting price increases for the next regulatory control period.[853]

17.4.8 Pricing structures and environmental goals

Parramatta City Council[854] and Baulkham Hills City Council[855] stated that in order to address the problem of climate change, it is necessary to provide financial incentives to all electricity users to reduce electricity consumption. They considered that increasing fixed costs, such as network charges, would not assist as it does not provide the right incentives.

Fairfield City Council submitted that the current pricing structure does not support energy efficiency or encourage more efficient use of energy for street lighting as a significant component of the network charge is fixed.[856]

WSROC called for charging structures which achieve energy efficiency and environmental goals; are not unnecessarily complex; and transparent in the application of various charges.

EnergyAustralia stated that its public lighting pricing proposal does not include fixed charges. It noted that customers are charged on a variable basis (per unit of installed public lighting components). EnergyAustralia stated that while its network use of service charges include a fixed charge, the network use of system tariff for public lighting customers does not include a fixed charge.[857]

17.4.9 Customers ability to pay

Campbelltown City Council asked the AER to consider the ability of local government to pay for the proposed cost increases and its impact on the level of services able to be provided by council to its community. It also stated that the AER should consider whether Integral Energy should provide some contribution to a community service obligation for street lighting.[858] Liverpool City Council supported these submissions.[859]

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852 SSROC, p. 1.
853 EnergyAustralia, *Supplementary response*, p. 8.
854 Parramatta City Council, p. 2.
855 Baulkham Hills City Council, p. 2.
856 Fairfield City Council, p. 4.
857 EnergyAustralia, *Supplementary response*, p. 8.
858 Campbelltown City Council, p. 3.
859 Liverpool City Council.

Blacktown Council supported Integral Energy's proposal[860] that councils seek recognition of the impact of the price increase through the 'rate pegging' process as a means to fund the increased charges.[861]

EnergyAustralia submitted that it is sympathetic to the situation its public lighting customers face in relation to their budgets and rate pegging, but notes that the issue of rate pegging is outside the scope of this determination process.[862]

EnergyAustralia stated that the issues surrounding the price of public lighting are largely a consequence of IPART's 2004 decision to classify public lighting as an excluded distribution service, which required EnergyAustralia to unwind the historical subsidy provided by network tariffs. EnergyAustralia stated that it considers its proposal to be cost reflective and notes that it has included a transitional rebate to manage price impacts.[863]

17.5 Consultant review

The AER engaged Wilson Cook to undertake a review of the NSW DNSPs' expenditure proposals for the next regulatory control period, including expenditure in relation to public lighting.

Wilson Cook noted that Country Energy's proposed level of capex for public lighting shows no change from that in the current period and that its proposed increase in opex is due to the commencement of a bulk lamp replacement program. Wilson Cook noted Country Energy's explanation that the 2008–09 financial year is the first year of its bulk lamp replacement program and that the full benefit will not be realised until later as an allocation for a high rate of spot lamp replacement and maintenance is still required.[864] Wilson Cook concluded that Country Energy's proposed public lighting expenditure is prudent and efficient.[865]

Wilson Cook noted that it had reviewed EnergyAustralia's public lighting expenditure for the 2003–04 to 2008–09 financial years for IPART in August 2005. As part of that review it noted that:

- the level of EnergyAustralia's capex was expected to be sustained for around eight years but was below a sustainable long term level
- some savings in opex ought to be realised after the 2005–06 financial year.

For the purposes of the current review, Wilson Cook compared the expenditure requested and approved in the 2005 review (converted into 2009 dollars) with EnergyAustralia's actual and projected expenditure for the current and next regulatory control periods.

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860 Integral Energy, *Regulatory proposal*, p. 225.
861 Blacktown City Council, *Response to AER's request for submissions on NSW DNSPs' regulatory proposals*, 15 August 2008, p. 1.
862 EnergyAustralia, *Supplementary response*, p. 5.
863 EnergyAustralia, *Supplementary response*, p. 3.
864 Wilson Cook, volume 4, p. 44.
865 Wilson Cook, volume 4, p. 46.

Wilson Cook noted that the increase in capex to date is consistent with its 2005 findings but the increase in opex was not.[866]

Wilson Cook stated that if the AER continues a building block approach for public lighting, it recommends that EnergyAustralia's proposed capex for public lighting be accepted but, in the absence of a case from EnergyAustralia for an increase, its proposed opex for public lighting be maintained at its level in the 2007–08 financial year in real terms.[867]

Wilson Cook also noted that it had reviewed Integral Energy's public lighting expenditure for the 2006–07 financial year for IPART in October 2007 and again in January 2008 after Integral Energy tabled a revised proposal.[868] It considered that Integral Energy's proposed public lighting expenditure for the next regulatory control period was in line with its earlier detailed assessment of public lighting expenditure requirements and concluded that Integral Energy's proposed public lighting expenditure is prudent and efficient.[869]

17.6 Issues and AER considerations

17.6.1 Regulatory asset base

In its final decision on alternative control services[870] the AER's intent was to allow the NSW DNSPs to roll forward the regulatory asset base derived from IPART's previous determination.[871] The AER's statement on alternative control services sets out that the NSW DNSPs may base the opening valuation of their respective RABs on the value derived from IPART's previous determination, with any efficient adjustments for capex and depreciation. The AER proposed that the asset valuation for public lighting should be derived by deducting the opening RAB from the 2004-09 regulatory control period (which only included prescribed services) from the closing RAB from the 1999–04 regulatory control period (which included both prescribed and public lighting services) (the AER's formula). This approach was suggested as it did not involve a bottom–up evaluation, reduced administrative costs and was verifiable.

While all the NSW DNSPs have complied with the transitional chapter 6 rule requirement to provide a demonstration of the AER's approach to regulating alternative control services, EnergyAustralia and Country Energy have proposed a different method for calculating the RAB. Both EnergyAustralia and Country Energy argued that it is not appropriate to roll forward the RAB, choosing instead to apply an ODRC asset valuation.

The AER expected the NSW DNSPs to present an asset valuation derived from the previous determination utilising the AER's formula.[872] It also expected that the NSW

[866] Wilson Cook, volume 2, p. 63.
[867] Wilson Cook, volume 2, p. 64.
[868] Wilson Cook, volume 3, p. 44.
[869] Wilson Cook, volume 3, p. 47.
[870] AER, *Final Decision—Control mechanisms for alternative control services for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008, pp. 14–16.
[871] AER, *Final Decision—Control mechanisms ACT and NSW*, p. 15.
[872] AER, *Final Decision—Control mechanisms ACT and NSW*, p. 16.

DNSPs would provide robust data to justify the asset base.[873] However, EnergyAustralia and Country Energy's proposals state that IPART's approach to removing the RAB from prescribed to excluded services was not entirely transparent and may not have involved as rigorous a valuation as is desirable.

The AER has reviewed the reasons behind EnergyAustralia and Country Energy proposing alternative valuations to those that would result under the approach proposed by the AER. It does not consider that these valuations are appropriate as they are based on replacement costs and would result in the NSW DNSPs setting charges for depreciated assets based on the actual cost of a replacement asset. The AER is aware that many of the assets in the DNSP's asset bases were constructed some time ago and therefore have a much lower value than that developed through a replacement cost approach. The AER also has concerns about the validity of a half life assumption for calculating depreciation. For the purpose of pricing services provided by existing assets the AER prefers a valuation derived from the previous determination utilising the AER's formula, on the basis that it is consistent with previous regulatory decisions and the depreciation that has occurred.

17.6.2 Efficiency of costs underlying proposed prices

A number of councils expressed concerns that EnergyAustralia's cost of service for public lighting is high and not supported by a robust demonstration of costs. They also stated that there were large and unsupported component price movements in EnergyAustralia's proposal, for example, new energy efficient lighting. Similarly, other councils stated that Integral Energy's proposal did not go into sufficient detail to demonstrate how it arrived at its proposed price changes (for example, disclosure of pricing models with detailed cost assumptions).

The AER has reviewed the costs contained in public lighting models developed by the NSW DNSPs. The AER has also reviewed the key assumptions used by the NSW DNSPs to develop their charges. Some of this information is claimed to be confidential (for example, supplier's quotes) and these claims need further assessment.

SSROC, REROC and Parramatta, Baulkham Hills and Bankstown City Councils' submitted that the AER should benchmark the prices being put forward by the NSW DNSPs. The AER has obtained data on actual capital and operating costs associated with key components of the NSW DNSP's replacement programs. The components analysed comprise a majority of the lights installed by the NSW DNSPs. As discussed in section 17.6.12, the AER intends to review these costs and the assumptions underlying them further in order to develop an efficient benchmark for each of the lighting types contained in the NSW DNSP's replacement programs. These benchmarks will be used by the AER to establish the schedules of prices for each NSW DNSP.

In relation to SSROC's submission regarding the longer asset lives of poles and brackets, the AER agrees that poles have longer asset lives than other public lighting elements such as luminaires and brackets. However, in relation to brackets the AER understands that, while these may have longer lives, they are generally required to be replaced at the same time as the luminaire. The AER considers that the standard life of poles should be 35

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873 AER, *Final Decision—Control mechanisms ACT and NSW*, p. 16.

years consistent with the standard lives of similar assets in other jurisdictions.[874] In section 17.6.11.1 the AER has indicated that poles should be modelled separately with a standard life of 35 years.

17.6.3 EnergyAustralia approach to retrofitting

SSROC submitted that it was unclear why having paid out undepreciated capital, there would be a basis for a rate 4 tariff at a premium to rate 1 and whether this premium would apply in perpetuity and, if so, on what basis. It also stated that it would be inappropriate for a customer to be required to reimburse the stranded costs of the component being replaced based on an arbitrary assumed age of half the asset life and/or half replacement value.

EnergyAustralia has clarified its regulatory proposal, stating that under rate 4 it does not use half the replacement value to calculate the stranded cost. It advised that it uses 100 per cent of the installation labour cost as a proxy for half the replacement value of the component being replaced.

EnergyAustralia submitted that it developed the rate 4 tariff in response to public lighting customers' requests to replace assets that have not reached the end of their useful lives with energy efficient lights. It stated that the rate 4 tariff takes into account the additional maintenance cost required when replacing either a luminaire or a bracket. Typically 90 per cent of the capitalised labour is allocated to the bracket and 10 per cent to the luminaire but with rate 4 prices 100 per cent of the capitalised labour has been allocated to the component being replaced, regardless of whether it is a bracket or luminaire. EnergyAustralia submits that this assumption has been made because, in these circumstances, both the luminaire and bracket will need to be replaced at the same time.[875]

The AER agrees that where a customer has requested replacement of an asset prior to the end of its economic life then a charge for the residual value of the capital in addition to the payment of efficient capital and maintenance costs of the new asset being installed is appropriate.

EnergyAustralia advised that the assumptions made by it are based on both the bracket and luminaire needing replacement in most instances and its requirement for compensation for the asset being replaced before the end of its economic life. From a review of EnergyAustralia's public lighting model, 100 per cent of the capitalised labour has been allocated to each component replaced under rate 4. This results in a 200 per cent labour charge effectively being applied under rate 4 where the bracket and luminaire are replaced before the end of their economic lives.

On the basis that generally luminaires and brackets are replaced at the same time, the AER does not believe it is appropriate that 100 per cent of the labour component be applied separately to the rates calculated for brackets and luminaires as this would result in double counting. Further, the AER does not consider that compensation for the asset

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874 Essential Services Commission of Victoria, *Final Decision, Review of public lighting excluded services charges*, August 2004, p. 61.

875 EnergyAustralia, *Supplementary response*, p. 10.

being replaced before the end of its economic life should be recovered through labour charges.

The AER also agrees with SSROC that it is not appropriate for a customer to be required to reimburse the NSW DNSP for the stranded costs of the component being replaced based on an arbitrary half life and/or half the replacement value.[876] The AER is aware that the NSW DNSPs do not have information regarding the remaining lives of their public lighting assets. In these circumstances, the AER considers that unless a NSW DNSPs can demonstrate that the remaining life of an asset (based on the type of asset and an assessment of its condition) is more than 10 years then its default age should be assumed to be at least three quarters of its assumed life.[877] Section 17.6.11.1 sets out the approach that the AER is requiring the NSW DNSPs to follow in developing their schedules of fixed prices.

17.6.4 Past technology selections

SSROC submitted that where EnergyAustralia has made inappropriate technology choices, given inappropriate advice to councils or continued practices in the field that EnergyAustralia management had agreed to halt, there needs to be financial consequences for EnergyAustralia or recourse for councils. In response to this claim, EnergyAustralia stated that its approach has been to evaluate and install luminaires that would avoid a maintenance regime that would increase cost of service to public lighting customers and decrease the effectiveness of public lighting to the community.[878]

The AER notes the findings of Wilson Cook in its August 2005 review of EnergyAustralia's public lighting capital expenditure and operational expenditure for IPART. In that report Wilson Cook states that responsibility for design of public lighting was ambiguous and that it was not clear that EnergyAustralia should bear responsibility for use in the past of luminaires or lamps that councils now consider inappropriate, although EnergyAustralia's actions, or lack of responsiveness may have contributed to the situation.[879]

If it can be demonstrated that EnergyAustralia has installed lights that were clearly outdated technology and not consistent with good industry practice then there may be a case for recourse. However, this is difficult to prove and the AER has not been provided with any evidence that substantiates the claim made. The AER notes that under section 14 of the Public Lighting Code, public lighting customers are to be provided with a list of standard luminaires and customers must be consulted about any changes to the list. In addition, the NSW DNSPs must give reasonable consideration to requests from customers to add specific technologies to the list. If this is not occurring then they may have some recourse under the dispute resolution provisions of the Public Lighting Code. The AER notes that under section 15.2 of the Public Lighting Code, a NSW DNSP is under no obligation to install or maintain luminaires which are not on the standard luminaire list. (In any event the proposed pricing schedule for replacement assets will require the NSW

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876 SSROC, p. 5.

877 This assumption takes into account the information on asset lives contained in Wilson Cook's report for the AER - see Wilson Cook, volumes 2, 3 and 4, table 2.2.

878 EnergyAustralia, *Supplementary response*, p. 11.

879 Wilson Cook, *Review of EnergyAustralia's Public Lighting Capital Expenditure and Operational Expenditure*, August 2005, p. 9.

DNSP to advise the customer three months in advance of the need for replacement so that the customer is able to choose from the list of standard luminaires the replacement asset and is made aware of the tariff associated with its replacement decision.)

The AER's role in making this determination is a forward looking one, to establish a set of charges for public lighting services in the first year of the next regulatory control period and a price path over the remainder of the period. In discussions with the NSW DNSPs the AER has been assured that they are already offering or will soon offer a number of energy efficient lighting options and have confirmed that they consult with their customers as to the lighting assets that they would like installed. The schedule of prices for public lighting services assumes that customers determine the type of the new or replacement asset being installed.

17.6.5 Appropriateness of the annuity method

EnergyAustralia has proposed an annuity approach to calculate the cost of service provision to determine a fixed schedule of prices. It stated that its proposed annuity methodology would establish a price which is effectively an annual rental for each public lighting component.[880] EnergyAustralia stated that the annuity methodology establishes a constant annual charge for each component which simplifies prices whilst maintaining net present value neutrality.[881] It noted that it calculated the annuity capital charge based on:

- the replacement value of the asset component
- the useful life of the asset (20 years)
- a real rate of return consistent with the rate of return determined by the AER.[882]

SSROC submitted that EnergyAustralia's annuity based approach is an inappropriate and costly change. It stated that EnergyAustralia's annuity based calculations appear to overstate costs by about 18 per cent compared to a building block approach.

It is unclear how SSROC has calculated that EnergyAustralia's annuity based calculations overstate costs by about 18 per cent compared to a building block approach. The AER considers that an annuity approach is an appropriate approach to apply to new assets but not to existing ones. The application of the annuity approach has the potential to overcompensate a DNSP where the assets are not new and the replacement cost of the asset has significantly increased.

Given the age of the NSW DNSPs existing assets and the significant increases in replacement costs of assets in recent times, the AER considers that a building block approach should continue to be applied to calculate an annual capital charge for those assets constructed prior to 1 July 2009, consistent with the approach set out in section 17.6.11.1. However, for assets constructed after 30 June 2009, the AER considers that an annuity approach should be used to determine an annual capital charge for these

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880 EnergyAustralia stated that, under this methodology, the combined amount of the return on capital and return of capital remains constant over the life of the asset although the components will vary relative to each other over time

881 EnergyAustralia, *Regulatory proposal*, p. 192.

882 EnergyAustralia, *Regulatory proposal*, p. 192.

assets where a customer agrees to rent these assets rather than to fund them itself and gift them to the DNSP.

17.6.6 Service levels

A number of submissions raised issues regarding service levels, including clarity about what prices are for and why they are seeing price increases without any corresponding improvement in service.

Consistent with its statement on alternative control services, the AER considers it appropriate to allow the NSW DNSPs to charge their public lighting customers prices which reflect the efficient costs of providing the level of service set out in the NSW Public Lighting Code. In this regard the AER notes that both Integral Energy and Country Energy have put forward public lighting proposals to achieve the service levels required by the Code. However, EnergyAustralia indicates that its proposal does not include an amount necessary to achieve compliance with the Public Lighting Code as a result of the lower prices provided by the 2004 IPART decision.

The AER has limited evidence concerning actual service levels and pricing outcomes. However, over the next regulatory control period the AER intends to collect and monitor actual service performance against the requirements of the Public Lighting Code.[883]

In relation to the claim that prices are increasing without any corresponding improvements in service levels, the AER considers that this does not automatically suggest that the NSW DNSPs are becoming less efficient. The causes for such increases could be the removal of subsidies or higher material and labour costs faced by the NSW DNSPs. In these circumstances, it is possible that prices could increase without a corresponding lift in the level of service provision.

17.6.7 Public Lighting Code

WSROC, Parramatta City Council and Baulkham Hills City Council made a number of claims regarding slow response times to complaints and faults. The AER notes that the NSW Public Lighting Code is voluntary code. Nevertheless, consistent with its final decision on alternative control services, the AER will require the NSW DNSPs to report their service performance against the service levels contained in the Code.[884] The AER will publish the NSW DNSPs' service performance and monitor their performance over the next regulatory control period. This information will assist the AER in establishing charges for public lighting services and customers in monitoring that they are receiving the level of service they are paying for.

Campbelltown Council and Liverpool City Council submitted that the AER should consider the need to review the Public Lighting Code and its service obligations to identify a more sustainable level of service for public lighting. The AER notes that it does not have any responsibility under the NER or the NEL for establishing service obligations in relation to public lighting and that this is the responsibility of the NSW Department of Water and Energy (DWE). The AER understands that DWE is intending to review the

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[883] AER, *Final Decision—Control mechanisms ACT and NSW*, p. 16.
[884] AER, *Final Decision—Control Mechanisms ACT and NSW*, p. 17.

Public Lighting Code in 2009 with a view to determining its effectiveness and whether any amendments are necessary.

17.6.8 Lack of information disclosure

SSROC, Parramatta, Bankstown and Baulkham Hills City Councils made submissions regarding a perceived lack of information disclosure and, in particular, EnergyAustralia's failure to provide its cost to serve model. Camden Council also stated that information which was not provided for confidentiality reasons prevented it from being able to understand significant cost increases potentially being imposed.

EnergyAustralia's cost to serve model was not provided with its regulatory proposal. However, following councils' raising the matter at the public forum on public lighting, the AER sought additional information from EnergyAustralia including its cost-to-serve model. In response to the AER's request, EnergyAustralia provided the AER with its cost-to-serve model. It also provided the AER with a scaled down version of the cost-to-serve model for each council (due to confidentiality concerns) and responses to a number of questions raised by the councils. The scaled down version of the cost-to-serve model and EnergyAustralia's responses were provided by the AER to the councils.

The AER seeks to provide interested parties with as much information as possible about each of the NSW DNSPs' regulatory proposals to enable interested parties to make submissions. As part of this process decisions must be made about claims for confidentiality. Much of the information concerning the public lighting proposals is contained in cost-to-serve models provided by the NSW DNSPs. These models contain confidential information regarding suppliers' prices, internal business allocations and customers' asset inventories. Given that a substantial amount of confidential information is contained in these models, the AER has not made them public. Nevertheless, the AER has reviewed each model, and based on this review, has developed a general approach to the development of price schedules that it believes will result in efficient public lighting prices. This approach is contained in section 17.6.11.1.

17.6.9 Pricing structures and environmental goals

Parramatta City Council, Baulkham Hills City Council and Fairfield City Council submitted that public lighting charges should be structured in order to provide financial incentives to reduce electricity consumption in order to tackle the problem of climate change. They stated that increasing fixed costs such as network charges would not assist as it does not provide the right incentives.

The AER considers it appropriate to allow the NSW DNSPs to charge prices which reflect the efficient costs of providing public lighting services. The AER notes that the national electricity objective is intended to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity.[885] The AER must perform its economic regulatory function in a manner which will, or is likely to, contribute to the achievement of the national electricity objective.[886] When exercising discretion in making those parts of a distribution determination relating to alternative control services, the AER may take into account the revenue and pricing

[885] NEL, section 7.
[886] NEL, section 16(1)(a).

principles set out in section 7A of the NEL if it considers it appropriate to do so.[887] Relevantly, the revenue and pricing principles provide that a DNSP should be provided with:

- a reasonable opportunity to recover at least the efficient costs the operator incurs in providing direct control network services[888]

- effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides.[889]

The AER considers that it is appropriate to apply the principles set out above to alternative control services.

The AER must make its determination under the NER. The NER do not require that prices be structured to reduce electricity consumption, only that the prices for direct control services lie between avoidable cost and the cost of stand alone provision (see clause 6.18.5(a) of the transitional chapter 6 rules). More generally, retail contestability should provide councils with a mechanism to negotiate competitive terms for energy use.

The AER notes that at the end of the economic life of a public lighting asset a customer is able to replace the existing light with an energy efficient light. In addition, a customer may choose to replace an asset before to the end of its standard life. This may be economic where the savings in electricity consumption by installing energy efficient lighting exceed the residual capital charges associated with the asset being replaced.

17.6.10 Customers ability to pay

The AER notes that in deciding the control mechanism for alternative control services, it must have regard to the factors in clause 6.2.5(d) of the transitional chapter 6 rules, and these do not refer specifically to the ability of consumers to pay.

According to section 16 of the NEL the AER must exercise its economic regulatory functions to promote the national electricity objective (section 7) and having regard to the revenue and pricing principles (section 7A), which do not refer to consumer ability to pay. Councils' ability to pay for the proposed increases and its impact on the level of services able to be provided by councils are not factors that can be taken into direct consideration. While rate pegging may impact on councils' ability to afford higher prices for public lighting, the AER considers it is required to set prices to reflect the economic cost of service provision, which is not limited to or by the rate peg limit or the side constraint provisions contained in the NER.[890]

17.6.11 Schedule of fixed prices control mechanism

In its statement on control mechanisms for alternative control services, the AER concluded that a fixed schedule of prices (based on revenues determined from a limited

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887 NEL, section 16(2)(b).
888 NEL, section 7A(2)(a).

889 NEL, section 7A(3).
890 The AER understands that councils are able to make a special variation application as part of the rate peg process for specific rate increases as a means of funding the increased public lighting charges.

building block approach) and a price path for the remaining years of the regulatory control period was an appropriate form of control.[891] This was viewed as providing a reasonably robust basis for assessing the efficient costs of providing the service as well as providing users with information on price levels over the regulatory control period.

17.6.11.1 Modified approach to the establishment of a schedule of prices

From its review of the public lighting proposals put forward by the NSW DNSPs and submissions from interested parties the AER considers that a modified approach to that set out in the AER's statement on the control mechanism for alternative control services is warranted for the following reasons:

- current pricing schedules do not reflect the actual cost of providing public lighting services
- the AER has reviewed data on the cost of constructing and maintaining various categories of luminaire and is concerned that the NSW DNSPs' construction and maintenance costs are not reflective of their current price schedules, nor is it possible to reconcile data on the disparity of construction and maintenance costs between the NSW DNSPs
- while each of the NSW DNSPs has an asset register of public lighting assets they do not have comprehensive records on the age and condition of these assets. It is therefore not clear that a half life modelling assumption is appropriate
- the fact that the NSW DNSPs have a large stock of assets of considerable age suggests that charges based on current replacement cost for those assets is not appropriate
- there is evidence that some customers are currently cross subsidising other customers.

To overcome the issues identified above, the AER considers that it is necessary to develop two schedules of prices, one for assets constructed prior to 1 July 2009 and another for those assets constructed after 30 June 2009. The prices for new and existing public lighting assets will need to distinguish between the maintenance cost of the asset and its capital cost. The AER's assessment is that the annual maintenance charge would be broadly similar for most categories of luminaire irrespective of age but that the capital charge for existing assets would be substantially less than the capital charge for a new asset.

In developing the capital charges underlying the two schedules of prices, the AER proposes that a building block approach be used for existing assets and an annuity approach be used for the capital charge for new assets. The AER has proposed a building block approach for existing assets due to the concerns it has about the use of a half life assumption and replacement costs for these assets. In relation to new assets the AER notes comments made by SSROC that EnergyAustralia's use of an annuity approach is an inappropriate and costly change in approach. The AER considers that an annuity approach is appropriate if it is only applied to new assets, the capital costs of which have

[891] AER, *Statement on control mechanisms for alternative control services for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008, pp. 4–5.

been determined on an efficient basis. Further, the AER considers that an annuity approach should be used for new assets as it should result in relatively stable charge and therefore provide customers with greater certainty regarding their charges over the next regulatory control period.

As required by clause 6.2.5(d) of the transitional chapter 6 rules, the AER had regard to the factors set out in that clause when it considered the appropriate control mechanism for alternative control services. The AER notes that these factors were also considered in its final decision on alternative control services.[892] The AER has not changed its position from that set out in the final decision and considers that a schedule of fixed prices continues to be the appropriate form of control for the same reasons as those set out in its final decision.

The AER requires that the NSW DNSPs develop two proposed schedules of prices for the first year of the next regulatory control period based on the following approaches.

Establishing a proposed schedule of prices for new assets

The following approach should be undertaken by the NSW DNSPs to develop a proposed schedule of prices for assets constructed after 30 June 2009:

- Determine **annual capital charge** (return on and of) based on efficient material and installation costs for assets in the DNSP's replacement program. The annual capital charge should be calculated based on an annuity approach using a standard life of 20 years for luminaires (including the lamp) and brackets and the WACC contained in the AER's draft decision for standard control services. An annual capital charge for poles is to be calculated separately using an annuity approach and a standard life of 35 years.[893]

- Determine an **annual maintenance cost** for each asset in the DNSP's replacement program based on efficient labour and materials costs (it is assumed that this maintenance cost would be based on a three year 'spot within bulk replacement program' and that maintenance costs are the same for new and existing assets).[894]

- An **annual charge** for each asset is to be calculated by adding the relevant annual capital charge and the annual maintenance cost where the DNSP funds and constructs the asset.

- The **total annual charge** for a customer is to be calculated by multiplying the expected number of assets to be constructed for a customer in 2009–10 by the relevant tariff class that will apply (section 17.6.11.2).

892 AER, *Final Decision—Control mechanisms ACT and NSW*, pp. 18–19.

893 The AER is aware that the majority of public lights are mounted on poles that are dedicated network poles and therefore customers are generally not charged for the capital costs associated with the assets.

894 The term 'Spot within bulk replacement program' means that the maintenance costs include both spot and bulk replacement and that these costs take into account the lower level of spot replacement that occurs due to the bulk replacement program being undertaken.

- Subsequent year charges are to be calculated by multiplying the first year's schedule of charges by an appropriate escalator (for example, CPI). Each of the NSW DNSPs is to nominate an escalator.

- A DNSP will need to advise a customer three months in advance of the commencement of an asset replacement program. At this time the DNSP will provide an indicative annual charge for the replacement assets and the reduction in the old asset charge.

From 1 July 2009 the NSW DNSPs will be required to maintain a register of all public lighting assets distinguishing between those constructed after 30 June 2009 and the remaining asset base. The register will note whether the asset is owned by the DNSP or the customer; the total cost of the asset (both upfront capital and installation costs) and the date the asset was installed.

Customers should have a choice concerning whether they fund new assets or if the assets are to be funded by the DNSP with a 'rental' charge. Where assets are funded by a DNSP an annual capital charge is payable, in addition to the annual maintenance charge.

Establishing a proposed schedule of prices for existing assets

The following approach should be undertaken by the NSW DNSPs to develop a proposed schedule of prices for assets constructed before 1 July 2009:

- Determine the 2009 closing asset base for alternative control services using IPART's 2004 opening asset base and add to that amount the actual capex that has occurred during the current regulatory control period less an allowance for depreciation based on the average remaining lives.

- Allocate the 2009 closing asset base to individual public lighting customers using individual asset inventories.

- Calculate a total **annual capital charge** for each customer for each year of the next regulatory control period using the 2009 closing RAB for each customer and an average remaining life for the assets related to each customer. The average remaining life is to be estimated by the DNSP on the basis of the type and condition of the assets within the public lighting RAB. The NSW DNSPs' average remaining life estimates must be supported by documented analysis. Alternatively a default specified by the AER is to be applied. No forecast capex or opex is to be applied in this building block model.

- Calculate an **annual maintenance cost** for each asset based on efficient labour and materials costs (it is assumed that this maintenance cost is based on a three year spot within bulk replacement program and that maintenance costs are the same for new and existing assets).

- Calculate the **total annual maintenance charge** for each customer by multiplying the number of assets in the asset register for the customer by the annual maintenance costs associated with each asset.

- Determine the **total charge payable** by a public lighting customer by adding the total annual capital charge to the total annual maintenance charge.

When assets come to the end of their economic lives customers should be provided with the opportunity to choose what type of asset will replace existing ones and to advise the DNSP as to whether it would like to fund the replacement assets (as per tariff class 5 below) or have the DNSP fund the replacement assets (as per tariff class 3 below). Over time the number of assets in the existing asset base will decline and be phased out and the number of assets in the new asset register will increase.

17.6.11.2 Tariff classes to apply

The schedules of prices developed by the NSW DNSPs will need to be established in accordance with the following tariff classes. Each asset will have a pre and post 1 July 2009 charge.

Assets constructed before 1 July 2009

Tariff class 1 (assets owned and constructed by the DNSP) – For assets constructed before 1 July 2009 and owned by the DNSP, the DNSP will be entitled to charge an annual maintenance charge (based on annual efficient maintenance costs) and an annual capital charge based on the IPART approved asset base for excluded services. If customers can demonstrate that past charges incorporated a charge toward future replacement cost or that the assets were gifted to the DNSP then this amount should be deducted from the existing asset base in order to avoid double recovery of these costs.

Tariff class 2 (assets owned and constructed by a customer) – For assets constructed before 1 July 2009 and owned by the customer, the DNSP will be entitled to charge an annual maintenance charge based on annual benchmark maintenance costs.

Assets constructed after 30 June 2009

Tariff class 3 (assets owned and constructed by the DNSP) – For assets constructed after 30 June 2009 and owned by the DNSP, the DNSP will be entitled to charge an annual maintenance charge (same as the tariff applying to tariff class 2) and an annual capital charge based on efficient material and installation costs (using an annuity approach).

Tariff class 4 (assets gifted by customer)– If the assets are gifted to a DNSP then these assets are to be treated by the DNSP as a capital contribution and no return on or of capital is entitled to be earned by the DNSP on these assets. However, the DNSP will be able to charge the customer for the efficient costs of maintaining the assets (same as the tariff applying to tariff class 2).

Tariff class 5 (customer funded) – When assets are scheduled to be replaced, a customer may decide to fund the purchase and installation of the new asset itself. If this occurs the tariff would be calculated based on efficient maintenance costs (same as the tariff applying to tariff class 2). However, in this situation the DNSP would not be entitled to a return on and of capital associated with these assets.

Tariff class 6 (replacement of assets before the end of their economic life) – A customer is able to request that an asset be replaced before the end of its economic life (for example, the replacement of an older luminaire with a more modern energy efficient luminaire). In these cases the customer will be required to pay for a condition based residual capital charge on the asset being replaced. (Unless it can be demonstrated that the remaining life of an asset is more than 10 years – based on the type of asset and an assessment of its condition - then its residual value will be based on a default age of at least three quarters of its assumed life.) Upon installation of the new asset, the efficient maintenance costs and the relevant annual capital charge (depending on the ownership arrangements) would also be payable. This tariff class would therefore be based on the efficient maintenance costs and capital charges (calculated as per tariff classes 3 or 5, depending on whether the asset is owned by the DNSP or the customer respectively). The DNSP is required to provide a discount to the customer on its efficient maintenance charges if the asset replacement is aligned with a bulk replacement program as the full maintenance effort would not be required.

Charges calculated for connecting public lighting assets must be cost reflective and non-discriminatory. These charges should be consistent with the costs of connecting other network users to the shared distribution network.

A summary of the six tariff classes proposed by the AER and the basis for their determination is set out in table 17.8.

Table 17.8: Summary of tariff classes and their determination

Tariff class	Description of tariff	Basis of tariff determination
Assets constructed prior to 1 July 2009		
1.	Asset owned and constructed by the DNSP	Annual efficient maintenance costs. Capital charge based on IPART approved asset base.
2.	Asset owned and constructed by the customer	Annual efficient maintenance cost. DNSP not entitled to a return on or of capital.
Assets constructed after 30 June 2009		
3.	Asset owned and constructed by the DNSP	Annual efficient maintenance costs (same as that calculated for tariff class 2). Annual capital charge (return on and of) based on efficient material and installation costs.
4.	Assets owned by customer but gifted to the DNSP	Annual efficient maintenance costs (same as that calculated for tariff class 2). DNSP not entitled to a return on or of capital.
5.	Assets owned by the customer but maintained by the DNSP	Annual efficient maintenance costs (same as that calculated for tariff class 2). DNSP not entitled to a return on or of capital.
6.	Assets owned by the DNSP but replaced at the request of the customer before the end of their economic lives	Tariff based on annual efficient maintenance costs. Annual capital charge based on ownership arrangements (that is, either tariff class 3 or 5). Discount provided on maintenance costs for aligning asset replacement with DNSP's bulk maintenance cycle. Residual asset charge calculated for replaced asset based on remaining life determined through an assessment of the assets condition or AER default value.

17.6.12 AER comparison of public lighting tariffs

The AER has attempted to compare current and proposed tariffs for common replacement lighting types with indicative tariffs developed by the AER based on cost information provided by the NSW DNSPs. These lights constitute a significant proportion (60–80 per cent) of the total lights installed by the NSW DNSPs.

To develop indicative cost based tariffs the AER has calculated annual capital and maintenance charges for each light. A capital charge has been developed for each light by obtaining the material costs associated with the relevant luminaire, bracket and lamp. To this amount has been added the installation costs (materials and labour) for each type of light. Using this total cost, an annual capital charge based on an annuity approach has been calculated for each light (based on a 20 year standard life and the AER's draft WACC).[895]

To determine the annual maintenance charge associated with each light the AER has obtained from each of the NSW DNSPs the annual material and labour costs associated with maintaining each light as part of their regular maintenance cycle (that is, both bulk and spot replacement programs).[896]

Table 17.9 contains the total upfront capital costs (both material and installation) and the annual maintenance cost (labour and material) for each light. This table has been developed from information provided by each DNSP. The consistency of the data has yet to be established and therefore any conclusions are preliminary only.

The table shows that, in terms of capital costs, EnergyAustralia's are lower than Integral Energy's for minor lighting types but that EnergyAustralia's capital costs are higher than Integral Energy's for major lighting types.[897] Country Energy's upfront capital costs are significantly higher than both Integral Energy's and EnergyAustralia's for both major and minor lighting types.

In terms of maintenance expenditures table 17.9 shows that Integral Energy has the lowest maintenance costs for each lighting type (except for the 80W MV light where EnergyAustralia's are lower). EnergyAustralia's maintenance costs are generally higher than Integral Energy's. Country Energy's maintenance costs are significantly higher than both Integral Energy and EnergyAustralia. Integral Energy appears to have the lowest maintenance costs due to lower costs associated with its bulk replacement program.

Based on the capital and maintenance costs in table 17.9, annual indicative tariffs have been developed by the AER for the NSW DNSPs in respect of each lighting type by adding the relevant annual capital and maintenance charges. Table 17.10 contains these annual indicative tariffs. The tariffs are shown for the AER's proposed tariff classes 3 (funded and constructed by the DNSP – capital and maintenance charges apply) and 5 (funded and constructed by the customer – maintenance charges only apply). Table 17.10

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[895] The cost of poles has been excluded from the analysis due to the number of different types, wide variation in cost and the fact that most public lights are mounted on poles whose primary purpose is to provide distribution network services.

[896] In general most DNSPs undertake a three year bulk replacement cycle, that is, all lamps are replaced once every three years. Such cycles result in reductions in the amount of spot replacement that is required compared to the situation where no bulk replacement is undertaken.

[897] Minor lights are those equal to or below 150W and major lights are those above 150W.

also compares the indicative tariffs for each of the NSW DNSPs with their current (2008–09) tariffs and the tariffs proposed by the NSW DNSPs for the first year of the next regulatory control period (2009–10).

Table 17.9: AER comparison of public lighting capital and maintenance costs for common replacement lighting types ($ per light, 2008–09)

Light type	DNSP	Total upfront capital costs[a]	Annual maintenance costs
2*20W TF	EnergyAustralia	402	77
	Country Energy [b]	–	–
	Integral Energy[b]	643	35
80W MV	EnergyAustralia	396	26
	Country Energy	621	46
	Integral Energy	589	35
2*14W T5	EnergyAustralia	458	54
	Country Energy[c]	–	–
	Integral Energy	636	37
42W CFL	EnergyAustralia	512	42
	Country Energy	702	58
	Integral Energy	591	41
150W HPS	EnergyAustralia	526	60
	Country Energy	1196	69
	Integral Energy	674	40
250W HPS	EnergyAustralia	907	58
	Country Energy	1176	62
	Integral Energy	755	51
250W MV	EnergyAustralia	843	43
	Country Energy	1039	58
	Integral Energy	827	38
400W MV	EnergyAustralia	911	62
	Country Energy	1165	75
	Integral Energy	796	38

Source: AER analysis based on information provided by the NSW DNSPs.
(a) Relates to the acquisition and installation costs of a new luminaire, bracket and lamp.
(b) This light is no longer being installed.
(c) Country Energy is yet to offer this light type.

Table 17.10: Indicative tariffs compared to the NSW DNSP's current and proposed tariffs ($ per light)

Lighting type	AER indicative tariffs[a]		DNSP 2008–09 tariffs[b]		DNSP proposed 2009–10 tariffs[c]	
2*20W TF	**C + O Rate 3**	**O Rate 5**	**C + O Rate 3**	**O Rate 5**	**C + O Rate 3**	**O Rate 5**
EnergyAustralia	115	77	72	36	122	81
Country Energy[d]	–	–	–	–	–	–
Integral Energy[d]	96	35	64	n/a	67	n/a
80W MV						
EnergyAustralia	64	26	55	22	68	27
Country Energy	104	46	100	56	127	52
Integral Energy	90	35	46	33	49	35
2*14W T5						
EnergyAustralia	97	54	97	56	114	56
Country Energy[e]	–	–	–	–	–	–
Integral Energy	97	37	57	38	60	40
42W CFL						
EnergyAustralia	90	42	24	n/a	96	43
Country Energy	125	58	–[f]	–[f]	151	66
Integral Energy	97	41	–	–	–	–
150W HPS						
EnergyAustralia	110	60	96	42	116	62
Country Energy	183	69	163	103	207	78
Integral Energy	104	40	121	49	128	52
250W HPS						
EnergyAustralia	144	58	121	42	154	61
Country Energy	173	62	163	104	200	70
Integral Energy	122	51	112	39	118	42
250W MV						
EnergyAustralia	123	43	112	32	138	45
Country Energy	157	58	157	97	197	66
Integral Energy	116	38	111	53	117	56
400W MV						
EnergyAustralia	148	62	122	42	166.	65
Country Energy	186	75	161	100	216	84
Integral Energy	113	38	91	39	96	41

(a) Based on information provided by the NSW DNSPs and calculated in accordance with the AER's proposed approach.
(b) 2008–09 tariffs are the DNSPs' current tariffs.
(c) 2009–10 tariffs were proposed by the NSW DNSP's in their respective regulatory proposals.
(d) This light is no longer being installed.
(e) Country Energy is yet to offer this light.
(f) Light being offered from 2009–10 onwards.
n/a Tariffs have not been provided.

In reviewing the figures in table 17.10 it is important to note that the AER's indicative tariffs have been developed using an annuity based approach that uses replacement cost values provided by the NSW DNSPs. The AER understands that EnergyAustralia's current tariffs have been based upon historical asset costs and a half life asset assumption. EnergyAustralia's proposed tariffs have been calculated on an annuity based approach using replacement costs. Country Energy's current tariffs have been developed based on replacement costs and a half life asset assumption. Country Energy's proposed tariffs have been developed by escalating cost reflective tariffs developed for 2008–09 by forecast inflation and real increases in EGW wages. Integral Energy's current tariffs have been developed using historical costs (rather than replacement costs) with a half life assumption. Integral Energy's proposed tariffs have been calculated by escalating their current tariffs by the X factors determined in their building block submission.

The AER observes a wide disparity in relation to the tariffs contained in table 17.10. It is not clear that the tariffs proposed by the NSW DNSPs are at an efficient level and therefore the AER is not able to finalise its view on this matter. The AER will undertake further analysis of the efficient capital and maintenance costs for these lighting types before it makes its final decision.

The NSW DNSPs will need to develop their proposed schedules of fixed prices for the first year of the next regulatory control period and their proposed price path for each subsequent year of that period using the approach set out in this section. The proposed prices and price path developed by the NSW DNSPs will be reviewed by the AER and compared against an efficient benchmark to be developed by the AER following further public consultation. Those proposed prices found to be around the benchmark prices will be viewed as efficient. For lights that have not been benchmarked, the AER expects that the capital and maintenance charges would be comparable to one of the lights contained in the benchmarking analysis. Where the prices proposed by the NSW DNSPs are not consistent with the relevant benchmark, the NSW DNSP will need to otherwise satisfy the AER that the charges are efficient.

The AER will include in its final decision the schedules of fixed prices for each of the NSW DNSPs for the first year of the next regulatory control period and the price path for each subsequent year of that period.

The AER expects to undertake the following consultation regarding the NSW DNSPs' proposed schedules of fixed prices and price path for alternative control services before making its final decision:

- the NSW DNSPs will submit their proposed schedules of fixed prices and price path by 16 January 2009 for publication on the AER's website
- on 9 March 2009 the AER will publish its proposed 2009–10 tariffs and the AER's proposed price path, for each NSW DNSP and seek submissions on these proposals
- submissions on the AER's proposed tariffs and price paths will be due by 23 March 2009
- the AER will include in its final determination (April 2009) a schedule of fixed prices and a price path for alternative control services for each NSW DNSP.

17.6.13 Compliance mechanisms

The NSW DNSPs are required to demonstrate compliance with the control mechanism applying to alternative control services. The AER considers that a compliance regime should be robust and administratively simple, where possible, to minimise costs on both the DNSPs and the AER.

The AER considers that compliance with the control mechanism can be demonstrated through an annual approval of changes in the schedules of prices. Each DNSP must submit its revised schedules of prices, that will apply in a regulatory year, 9 weeks prior to the commencement of each regulatory year in the next regulatory control period.

17.7 AER conclusions

The AER will require each NSW DNSP to develop two proposed schedules of fixed prices for the first year of the next regulatory control period and a price path for each remaining year of that period. The first proposed schedule of prices will relate to public lighting assets constructed before 1 July 2009 and the second will relate to public lighting assets constructed after 30 June 2009. The proposed schedules of prices must be developed in accordance with the approach set out in section 17.6.11. Following consideration of, and consultation on, the proposed schedules of prices and price path, the AER will determine the appropriate schedules of fixed prices for each NSW DNSP for the first year of the next regulatory control period. For each remaining year of that period the prices in the schedules will be permitted to increase in accordance with a price path approved by the AER.

17.8 AER draft decision

In accordance with clause 6.12.1(12) of the transitional chapter 6 rules, the AER decides that the control mechanism for alternative control services is:

- a schedule of fixed prices in the first year of the next regulatory control period for assets constructed before 1 July 2009 and a schedule of fixed prices in the first year of the next regulatory control period for assets constructed after 30 June 2009
- a price path, such as CPI, for the remaining years of the next regulatory control period.

Country Energy will submit its proposed schedules of fixed prices and price path to the AER by 16 January 2009 for consideration by the AER and for public consultation. Country Energy must follow the approach set out in section 17.6.11 of the draft decision when preparing its proposed schedules of fixed prices and price path.

In accordance with clause 6.12.1(12) of the transitional chapter 6 rules, the AER decides that the control mechanism for alternative control services is:

- a schedule of fixed prices in the first year of the next regulatory control period for assets constructed before 1 July 2009 and a schedule of fixed prices in the first year of the next regulatory control period for assets constructed after 30 June 2009
- a price path, such as CPI, for the remaining years of the next regulatory control period.

EnergyAustralia will submit its proposed schedules of fixed prices and price path to the AER by 16 January 2009 for consideration by the AER and for public consultation. EnergyAustralia must follow the approach set out in section 17.6.11 of the draft decision when preparing its proposed schedules of fixed prices and price path.

In accordance with clause 6.12.1(12) of the transitional chapter 6 rules, the AER decides that the control mechanism for alternative control services is:

- a schedule of fixed prices in the first year of the next regulatory control period for assets constructed before 1 July 2009 and a schedule of fixed prices in the first year of the next regulatory control period for assets constructed after 30 June 2009
- a price path, such as CPI, for the remaining years of the next regulatory control period.

Integral Energy will submit its proposed schedules of fixed prices and price path to the AER by 16 January 2009 for consideration by the AER and for public consultation. Integral Energy must follow the approach set out in section 17.6.11 of the draft decision when preparing its proposed schedules of fixed prices and price path.

In accordance with clause 6.12.1(13) of the transitional chapter 6 rules, the AER decides that compliance with the alternative control services control mechanism is to be demonstrated through annual approval of changes in the schedules of prices.

18 Pricing methodology for EnergyAustralia prescribed (transmission) standard control services

18.1 Introduction

This chapter sets out the AER's consideration of EnergyAustralia's proposed pricing methodology for the next regulatory control period. In accordance with clause 6A.29.1(a) of the NER, EnergyAustralia is an appointing provider in the NSW region. EnergyAustralia and the other TNSPs in NSW have nominated TransGrid as the co–ordinating network service provider. The co–ordinating network service provider is responsible for the allocation of the relevant aggregate annual revenue requirement (AARR) within the region.

18.2 Regulatory requirements

18.2.1 NER requirements

Clause 6.1.6(e) of the NER outlines the application of transitional chapter 6 rules to EnergyAustralia's transmission support network and provides that:

> Part J of Chapter 6A applies to EnergyAustralia prescribed (transmission) standard control services to the exclusion of Parts I, J and K, and so applies as if:
>
> (1) references in Part J of Chapter 6A to a prescribed transmission service were references to EnergyAustralia prescribed (transmission) standard control services; and
>
> (2) the reference in clause 6A.22.1 to clause 6A.3.2 were a reference to rules 6.6 and 6.13;
>
> and with any other necessary modifications.

Therefore EnergyAustralia's prescribed (transmission) standard control services pricing must comply with part J of chapter 6A of the NER.

Clause 6A.29.1 of the NER outlines the requirements where there are multiple transmission network service provider in a region. Clause 6A.29.1 states:

> (a) If prescribed transmission services within a region are provided by more than one Transmission Network Service Provider, the providers within that region (the appointing providers) must appoint a Co–ordinating Network Service Provider who is responsible for the allocation of all relevant AARR within that region, in accordance with this Part J.
>
> (b) Each Transmission Network Service Provider must determine the AARR for its own transmission system assets which are used to provide prescribed transmission services within each region.
>
> (c) To make the allocation referred to in paragraph (a), the Co–ordinating Network Service Provider must use the total AARR of all Transmission Network Service Providers providing prescribed transmission services within the relevant region.

d) The Co–ordinating Network Service Provider is responsible for making the allocation referred to in paragraph (a), in accordance with its pricing methodology, in relation to Transmission Network Users' and Transmission Network Service Providers' transmission network connection points located within the region and an appointing provider is not required to address the matters specified in rule 6A.24.1(b)(1) when preparing its pricing methodology.

Clause 6A.24.1(b) of the NER defines a pricing methodology in terms of the pricing principles as set out in clause 6A.23 of the NER:

A pricing methodology is a methodology, formula, process or approach that, when applied by a Transmission Network Service Provider:

(1) allocates the aggregate annual revenue requirement for prescribed transmission services provided by that provider to:

(i) the categories of prescribed transmission services for that provider; and

(ii) transmission network connection points of Transmission Network Users; and

(2) determines the structure of the prices that a Transmission Network Service Provider may charge for each of the categories of prescribed transmission services for that provider.

As an appointing provider EnergyAustralia is not required to address clause 6A.24.1(b)(1) of the NER.

The NER also prescribes the role of the AER with respect to approval of a TNSP's pricing methodology:[898]

The AER must approve EnergyAustralia's proposed pricing methodology for EnergyAustralia prescribed (transmission) standard control services if the AER is satisfied that the methodology:

(1) gives effect to and is consistent with the Pricing Principles for Prescribed Transmission Services; and

(2) complies with the requirements of the pricing methodology guidelines.

18.2.2 Pricing methodology guidelines requirements

The AER's pricing methodology guidelines (the guidelines)[899] were developed in accordance with clause 6A.25.1(a) of the NER. The guidelines specify or clarify:

(a) the information that is to accompany a proposed pricing methodology;

(b) permitted pricing structures for the recovery of the locational component of providing prescribed TUOS services;

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[898] Transitional chapter 6 rules, clause 6.12.3(i).

[899] AER, *Electricity transmission network service provider - pricing methodology guidelines*, October 2007.

(c) permitted postage stamp pricing structures for prescribed common transmission services and the recovery of the adjusted non–locational component of providing prescribed TUOS services;

(d) the types of transmission system assets that are directly attributable to each category of prescribed transmission services; and

(e) those parts of a proposed pricing methodology, or the information accompanying it that will not be publicly disclosed without the consent of the TNSP.

18.3 EnergyAustralia proposal

On 2 June 2008 EnergyAustralia submitted its proposed pricing methodology for the next regulatory control period to the AER. EnergyAustralia stated that its proposed pricing methodology is consistent with the requirements of chapter 6A of the NER.

In response to a request from the AER, EnergyAustralia resubmitted its proposed pricing methodology on 28 October 2008, to clarify components of its cost allocation methodology.[900]

EnergyAustralia's proposed pricing methodology outlines:[901]

- calculation of the AARR for each year of the next regulatory control period
- a methodology to determine whether assets fall into the prescribed transmission service categories
- allocating the AARR to the categories of prescribed transmission service
- allocation of the ASRR for each category of prescribed transmission service to connection points
- detailing the methodology for implementation of the priority ordering approach under clause 6A.23.2(d) of the NER including two worked examples
- billing arrangements
- management of prudential requirements and prudent discounts for new or existing connections to the EnergyAustralia transmission network
- a description of how asset costs which are associated with prescribed entry services and prescribed exit services at a connection point, which may be attributable to multiple transmission network users, will be allocated
- monitoring and compliance arrangements for its proposed pricing methodology.

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900 EnergyAustralia, *EnergyAustralia's Transmission Pricing Methodology – 1 July 2009 to 30 June 2014*, 28 October 2008, p. 3.

901 EnergyAustralia, *Transmission Pricing Methodology*, p. 3.

18.4 Issues and AER considerations

The pricing principles for prescribed transmission services contained in the NER (the pricing principles) outline the high level principles for the development of transmission prices while the guidelines supplement the pricing principles. The guidelines also outline the information that EnergyAustralia is required to provide in its proposed pricing methodology. In assessing EnergyAustralia's proposed pricing methodology, the AER has considered whether it gives effect to and is consistent with the pricing principles and whether it complies with the requirements of the guidelines.

The AER notes that this is the first time which EnergyAustralia has been required to lodge a pricing methodology, and that no pricing methodology has applied during the current regulatory control period. This is because the requirement for a pricing methodology was first introduced into the NER as part of the new pricing obligations under chapter 6A which took effect in December 2006, after commencement of the current regulatory control period.

This section outlines the AER's assessment of EnergyAustralia's proposed pricing methodology against the pricing principles and the guidelines.

18.4.1 EnergyAustralia's role as an appointing provider

EnergyAustralia proposal

EnergyAustralia stated that it is an appointing network service provider. Along with the other appointing providers in the NSW region, it has nominated TransGrid as the coordinating network service provider. EnergyAustralia stated that it will annually provide TransGrid with relevant information to ensure the proper calculation of prescribed transmission prices in New South Wales. [902]

EnergyAustralia noted that as an appointing provider, some elements of its transmission pricing are carried out by TransGrid. Those elements include:[903]

- adjustments to the locational component of the annual service revenue requirement (ASRR)
- adjustments to the pre–adjusted non–locational component of the ASRR
- allocation of the locational component of prescribed transmission use of system (TUOS) services to connection points
- determining the pricing structure for the common service, non–locational and locational charges for its transmission network connection points.

AER considerations

The AER considers that EnergyAustralia's explanation of its role as an appointing provider is consistent with clause 6A.29.1 of the NER. Furthermore, the information

[902] EnergyAustralia, *Transmission Pricing Methodology*, pp. 2–3.
[903] EnergyAustralia, *Transmission Pricing Methodology*, p. 3.

provided by EnergyAustralia to explain its role and responsibilities is sufficient in addressing the requirements of clauses 2.1(a) and (b) of the guidelines.

18.4.2 Determination of the AARR and its allocation to categories of prescribed transmission services

EnergyAustralia proposal

EnergyAustralia stated that the AARR would be derived in accordance with clause 6A.22.1 of the NER, calculated as:[904]

> the maximum allowed revenue referred to in clause 6A.3.1 adjusted:
>
> - in accordance with clause 6A.3.2; and
> - by subtracting the operating and maintenance costs expected to be incurred in the provision of prescribed common transmission services.

EnergyAustralia noted the portion of the annual revenue requirement relevant to prescribed (transmission) standard control services determined under clause 6.12.1A(a)(1) of the transitional chapter 6 rules is used to establish a MAR. It proposed to determine its AARR by adjusting its MAR in accordance with clauses 6.6 and 6.13 of the transitional chapter 6 rules and subtract the opex costs expected to be incurred in the provision of prescribed common transmission services.[905] It stated the relevant opex costs would be derived from budget projections.[906]

EnergyAustralia proposed to recover its AARR from the following categories of transmission services:[907]

- prescribed exit services
- prescribed common transmission services
- prescribed TUOS services.

EnergyAustralia noted that while it does not own any transmission assets providing entry services to a generator at this time, it has suggested a proposed methodology in anticipation of this service being required at some time in the future. Prescribed entry services include assets that are fully dedicated to serving a generator or group of generators at a single connection point.[908]

EnergyAustralia proposed the following methodology to recover its AARR:[909]

- classifying each asset utilised in the provision of prescribed transmission services into one of the above categories of service

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904 EnergyAustralia, *Transmission Pricing Methodology*, p. 4
905 Rule 6.6 refers to adjustments to a building block determination; rule 6.13 refers to the revocation and substitution of a distribution determination.
906 EnergyAustralia, *Transmission Pricing Methodology*, p. 4.
907 EnergyAustralia, *Transmission Pricing Methodology*, p. 4–5.
908 EnergyAustralia, *Transmission Pricing Methodology*, p. 4–5.
909 EnergyAustralia, *Transmission Pricing Methodology*, p. 5–7.

- calculating the attributable cost shares for each category of service in accordance with clause 6A.22.3 of the NER
- allocating the AARR to each category of prescribed transmission service in accordance with the attributable cost share for each category of prescribed transmission service. This allocation would result in the ASRR for that category of service.

EnergyAustralia provided hypothetical worked examples demonstrating how the AARR would be allocated to each category of prescribed transmission service so that the ASRR can be derived.

Appendix A of EnergyAustralia's proposed pricing methodology outlines its proposed priority ordering approach, as required under section 2.1(d)(2) of the guidelines. EnergyAustralia stated that it has used the priority ordering approach to determine costs for transmission assets that could be allocated to more than one class of service. Where there are assets that provide multiple services costs would be allocated in accordance with the stand alone costs for providing prescribed TUOS services and prescribed common transmission services with the remainder being allocated to prescribed entry and prescribed exit services.[910]

EnergyAustralia has assumed that substation infrastructure and establishment costs are proportionate to the number of high voltage circuit breakers in the substation. Accordingly, it has proposed to allocate substation infrastructure and establishment costs based on the ratio of the number of high voltage circuit breakers in the stand alone arrangement to the number of high voltage circuit breakers in the substation. Costs would be allocated to prescribed TUOS services based on the number of circuit breakers that would be required if the substation were built to provide prescribed TUOS services only.[911]

EnergyAustralia stated costs would then be allocated to prescribed common transmission services based on the number of circuit breakers that would be required had the substation been built solely for that purpose.[912]

The remaining costs would then be allocated to prescribed entry and/or prescribed exit services on the basis of the number of high voltage circuit breakers providing prescribed entry or prescribed exit services.[913]

In cases where prescribed services costs are attributable to both entry and exit services but are not subject to the priority ordering approach at a connection point, EnergyAustralia stated that costs would be shared between transmission customers based on the number of circuit breakers used in connecting the customer for each service.[914]

Where an asset provides exit services to several customers at a connection point the costs would be allocated by the proportion of the circuit breakers at the connection point for each customer.[915] EnergyAustralia provided hypothetical worked examples in its revised pricing methodology.

910 EnergyAustralia, *Transmission Pricing Methodology*, p. 10.
911 EnergyAustralia, *Transmission Pricing Methodology*, pp. 14–23.
912 EnergyAustralia, *Transmission Pricing Methodology*, p. 17.
913 EnergyAustralia, *Transmission Pricing Methodology,* pp. 14–19.
914 EnergyAustralia, *Transmission Pricing Methodology*, p. 17.
915 EnergyAustralia, response to AER information request, 11 September 2008.

AER considerations

The AER sought further clarification from EnergyAustralia on the allocation of costs which provide both prescribed entry and prescribed exit services. It also sought clarification on the allocation of costs to prescribed entry or prescribed exit services which could be attributable to multiple transmission network users. EnergyAustralia clarified these matters and stated the cost allocation in both instances would be done in a manner similar to that used under the priority ordering arrangements. That is costs would be allocated in proportion to the number of circuit breakers connecting customers to each service and it has included this information in its revised pricing methodology.[916]

The AER considers EnergyAustralia's proposed approach to calculating its AARR and its allocation to the categories of prescribed transmission services is consistent with the NER and the guidelines.

The AER considers EnergyAustralia's proposed priority ordering approach is consistent with the requirements outlined in the pricing principles specified in the NER. EnergyAustralia's proposed treatment of prescribed exit assets which are used by multiple transmission users is consistent with section 2.1(e)(l)(C) of the guidelines. The explanation provided by EnergyAustralia complies with the information requirements outlined in section 2.1(d)(2) of the guidelines.

18.4.3 Allocation of the ASRR to transmission network connection points

The final cost allocation step is to allocate the ASRR to each category of prescribed transmission service.

EnergyAustralia proposal

EnergyAustralia proposed to allocate its ASRR for prescribed entry services and its ASRR for prescribed exit services to connection points using the attributable connection point cost share outlined in clause 6A.22.4 of the NER.[917] It provided hypothetical examples of this allocation process in sections 3.7.1 and 3.7.2 of its proposed pricing methodology.

EnergyAustralia proposed to recover the costs associated with prescribed TUOS (shared network) services from the locational and adjusted non–locational component of prescribed TUOS services. EnergyAustralia noted that certain adjustments are made to the locational and non–locational components of prescribed TUOS services and stated that TransGrid, as the coordinating network service provider, conducts these adjustments and allocates costs to connection points. In its proposal, EnergyAustralia stated that it would provide information to TransGrid concerning any expected under or over recovery amount resulting from its pre–adjusted non–locational prescribed TUOS service charges from previous years to assist TransGrid in allocating costs to connection points.[918]

EnergyAustralia noted that allocation of the locational component of prescribed transmission services to connection points is conducted by TransGrid using the cost

[916] EnergyAustralia, response to AER information request, 11 September 2008.
[917] EnergyAustralia, *Transmission Pricing Methodology*, pp. 7–8.
[918] EnergyAustralia, *Transmission Pricing Methodology,* pp. 9–10.

reflective network pricing (CRNP) methodology prescribed in the NER. It stated that TransGrid use network pricing software called T–price to apply CRNP methodology.[919]

AER considerations

The AER considers the information provided by EnergyAustralia in relation to the allocation of the ASRR for prescribed entry services and prescribed exit services is sufficient to comply with section 2.1(e)(1)A of the guidelines and the hypothetical examples satisfy section 2.1(e)(1)B of the guidelines. Further, its proposed calculation of the attributable connection point cost share is consistent with clause 6A.22.4 of the NER.

The AER notes that EnergyAustralia's prescribed TUOS services are allocated to connection points by TransGrid as the coordinating network service provider for the NSW region.

18.4.4 Price structures

EnergyAustralia proposal

EnergyAustralia stated that prescribed entry and prescribed exit service prices are recovered via a daily fixed charge based on the calculated ASRR allocated to each category of service at each connection point.[920]

EnergyAustralia noted TransGrid, as coordinating network service provider, calculates prescribed common service, prescribed non–locational TUOS service and prescribed locational TUOS service prices.[921]

AER considerations

The AER considers EnergyAustralia's proposed methodology for calculating prescribed entry and prescribed exit service prices are consistent with the NER and the information provided is sufficient to satisfy clauses 2.1(f)(1) and (2) of the guidelines.

18.4.5 Additional information

The guidelines require TNSPs to provide additional information to demonstrate consistency with part J of chapter 6A of the NER.

EnergyAustralia proposal

EnergyAustralia has provided details of its approach to billing arrangements prescribed under clause 6A.27 of the NER. It stated that it would calculate charges in accordance with the transmission prices calculated by TransGrid and issue bills on a monthly basis. It noted that bills will be sent to electricity retailers rather than to the customer directly.[922]

EnergyAustralia stated that it may request a user to make a capital contribution where it is required to provide specific assets to provide connection services and TUOS services. In particular, EnergyAustralia may require a bank guarantee from a transmission customer to cover the financial year of a transmission investment made by EnergyAustralia for the

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[919] EnergyAustralia, *Transmission Pricing Methodology,* p. 9.
[920] EnergyAustralia, *Transmission Pricing Methodology*, p. 8.
[921] EnergyAustralia, *Transmission Pricing Methodology,* p. 10.
[922] EnergyAustralia, *Transmission Pricing Methodology,* p. 11.

customer. The proposal stated that these prudential requirements would be consistent with clauses 6A.28.1 and 6A.28.2 of the NER.[923]

EnergyAustralia noted that it has one prudent discount arrangement with one transmission customer. It provided the AER with a confidential version of its pricing methodology which outlined the prudent discount arrangement. EnergyAustralia requested that information on this prudent discount arrangement be kept confidential by the AER.[924]

EnergyAustralia provided details of how it intends to monitor and develop records of its compliance with the approved pricing methodology. In accordance with the pricing principles and part J of the NER, EnergyAustralia stated that it would:[925]

- Maintain the specific obligations arising from part J of the Rules in its compliance management system;
- Maintain electronic records of the annual calculation of prescribed transmission prices and supporting information; and
- Periodically subject its transmission pricing models and processes to functional audit by suitably qualified persons.

EnergyAustralia noted that it does not consider transitional arrangements necessary for its proposed pricing methodology. In particular, EnergyAustralia stated that it did not consider it necessary to make any derogations from chapter 9 of the NER, nor did it consider the transitional arrangements highlighted in chapter 11 of the NER relevant to its proposed pricing methodology.[926]

AER considerations

The AER considers that EnergyAustralia's proposed approach towards its billing arrangements, prudential requirements, prudent discounts and the monitoring and record keeping arrangements of its approved pricing methodology is consistent with part J of the NER. The AER notes that EnergyAustralia has provided sufficient information to satisfy the requirements of sections 2.1(k), (l), (m) and (s) of the guidelines.

Clause 11.8.5 of the NER relates to prudent discounts under existing agreements. Clause 11.8.5(c) states that the AER is not required to re-approve discounts that were approved prior to 28 December 2006 and notes that any approval for the recovery of discounts identified in clauses 11.8.5(a) and (b) are valid as long as the agreement between the TNSP and the customer remains in effect and has not been re–negotiated. In correspondence to the AER, EnergyAustralia noted its prudent discount arrangement has not been subject to re-negotiation since it came into effect.[927]

The AER considers that EnergyAustralia has provided sufficient reasons to support the inclusion of confidential material as part of its proposed pricing methodology, as required by clause 2.5 of the guidelines.

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923 EnergyAustralia, *Transmission Pricing Methodology,* p. 12.
924 EnergyAustralia, email to the AER, confidential, 20 August 2008.
925 EnergyAustralia, *Transmission Pricing Methodology,* p. 13.
926 EnergyAustralia, *Transmission Pricing Methodology,* p. 13.
927 EnergyAustralia, email to the AER, confidential, 20 August 2008.

In correspondence to the AER, EnergyAustralia stated that it was not required to have a pricing methodology in place for the current regulatory control period.[928] The AER notes that this is because it is operating under the National Electricity Code for the current regulatory control period. Under the National Electricity Code, a pricing methodology is not required. Accordingly, the AER considers that there was no requirement for EnergyAustralia to address clause 2.1(r) of the guidelines which requires a TNSP to provide a description of the differences between the pricing methodology applied in the current regulatory period and that proposed for the next regulatory control period.

18.5 AER conclusions

The AER has assessed EnergyAustralia's revised pricing methodology against part J of the NER and the pricing methodology guidelines. Based on that assessment, the AER has decided to approve EnergyAustralia's proposed pricing methodology, as set out in appendix T.

18.6 AER draft decision

In accordance with clause 6.12.1(20) the AER decides to approve EnergyAustralia's pricing methodology, as set out in appendix T of the draft decision.

[928] EnergyAustralia, email to the AER, confidential, 27 August 2008.

Glossary

2007 APR	TransGrid, *2007 NSW Annual Planning Report*, 30 June
2008 APR	TransGrid, *2008 NSW Annual Planning Report*, 30 June 2008
AARR	aggregate annual revenue requirement
ABARE	Australian Bureau of Agricultural and Resource Economics
ABS	Australian Bureau of Statistics
ACG	Allen Consulting Group
ANSIO	Econtech's Australian National State and Industry Outlook
AR	allowed revenue
ARPANSA	Australian Radiation Protection and Nuclear Safety Agency
ASP	accredited service provider - a person who has been accredited under Part 10 Electricity Supply (General) Regulation 2001 (NSW)
ASRR	annual service revenue requirement
AUD	Australian dollar
Bppa	basis points per annum
CAPM	capital asset pricing model
CBD	central business district
CE	Country Energy
CEG	Competition Economists Group
CFC	Construction Forecasting Council
CFL	compact fluorescent lamp
CGS	Commonwealth Government Securities
CIE	Centre for International Economics
CRA	Charles River Associates International
CRNP	cost reflective network pricing
DEEWR	Department of Education, Employment and Workplace Relations
DEUS	NSW Department of Energy, Utilities and Sustainability (now DWE)
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DORC	deprecated optimised replacement cost
DRP	debt risk premium
DWE	NSW Department of Water and Energy
EA	EnergyAustralia
EBA	Enterprise Bargaining Agreement

EBIT	earnings before interest and taxes
EBITDA	earnings before interest, taxes, depreciation and amortization
EBSS	efficiency benefit sharing scheme
EGW	electricity, gas and water
EMF	electromagnetic fields
EMRF	Energy Markets Reform Forum
EMS	Energy and Management Services Pty Ltd
ESCV	Essential Services Commission of Victoria
EUAA	Energy Users Association of Australia
Excluded distribution service rule	Rule to which unregulated distribution services are subject, available in: IPART, *Final Report: NSW Electricity Distribution Pricing, 2. Regulation of Excluded Distribution Services Rule 2004*, June 2004, Appendix 2
GIS	geographic information systems
GSL	guaranteed service levels
GSP	gross state product
HRC	hot–rolled coil
HV	high voltage
ICT	information and communications technology
IE	Integral Energy
KPMG	KPMG Australia
LME	London Metal Exchange
MAIFI	momentary average interruption frequency index
MAR	maximum allowed revenue
MMA	McLennan Magasanik Associates
MRP	market risk premium
MSATS	market settlement and transfer system operated by NEMMCO
MVA	mega volt amperes
MW	mega watt
MWh	mega watt hour
NCC	negotiated component criteria
NDSC	negotiated distribution service criteria
NIEIR	National Institute of Economic and Industry Research
NMI	national metering identifier
NPV	net present value
NSP	network service provider

NSW DRP	NSW Government Design Reliability and Performance licence conditions
NTER	National Tax Equivalence Regime
NYMEX	New York Mercantile Exchange
ODRC	optimised depreciated replacement cost
OH	overhead
original DMIA	the DMIA applied by the AER in: AER, *Final Decision: Demand management incentives schemes for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008.
PB	Parsons Brinckerhoff Australia
PIAC	Public Interest Advocacy Centre
PPI	producer price indices
PTRM	post–tax revenue model
POE	probability of exceedence
Public Lighting Code	DEUS voluntary code of practice for a range of public lighting services in NSW
QCA	Queensland Competition Authority
RAB	regulatory asset base
RBA	Reserve Bank of Australia
replacement DMIA	the DMIA published in November 2008: AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme*, November 2008
REROC	Riverina Eastern Regional Organisation of Councils
RFM	roll forward model
RIN	regulatory information notice
RIO	regulation information order
RISMO	Country Energy's zero-based model used to project the quantity of inspection, vegetation control and maintenance works needed
SAHA	SAHA International
SAIDI	system average interruption duration index
SAIFI	system average interruption frequency index
SCADA	supervisory control and data acquisition
SCNRRR	Steering Committee on National Regulatory Reporting Requirements
SKM	Sinclair Knight Merz
SRP	TransGrid's Statement of Regulatory Principles
SSROC	South Sydney Regional Organisation of Councils

standard control services guideline	AER, *Final decision: Control mechanisms for direct control services for the ACT and NSW 2009 distribution determinations*, February 2008
STPIS	service target performance incentive scheme
TEC	Total Environment Centre
the IPART control mechanism	the control mechanism determined by IPART for the corresponding prescribed distribution services in the current regulatory control period
the NSW DNSPs	Country Energy, EnergyAustralia and Integral Energy
TNSP	transmission network service provider
transitional chapter 6 rules	transitional provisions set out at part M of chapter 11 of the NER
TUOS	transmission use of system
UG	underground
UK regulator	Office of Gas and Electricity Markets
USD	United States Dollar
WACC	weighted average cost of capital
WAPC	weighted average price cap
Wilson Cook	Wilson Cook and Co. Limited
WSROC	Western Sydney Regional Organisation of Councils

Appendix A: Assigning customers to tariff classes

Procedures for assigning or reassigning customers to tariff classes

Assignment of existing customers to tariff classes at the commencement of the next regulatory control period

1. Each customer who was a customer of a NSW DNSP immediately prior to1 July 2009, and who continues to be a customer of a NSW DNSP as at 1 July 2009, will be taken to be "assigned" to the tariff class which the NSW DNSP was charging that customer immediately prior to 1 July 2009.

Assignment of new customers to a tariff class during the next regulatory control period

2. If, after 1 July 2009, a NSW DNSP becomes aware that a person will become a customer of the DNSP, then the DNSP must determine the tariff class to which the new customer will be assigned.
3. In determining the tariff class to which a customer or potential customer will be assigned, or reassigned, in accordance with section 2 or 5, a DNSP must take into account one or more of the following factors:
   (a) the nature and extent of the customer's usage
   (b) the nature of the customer's connection to the network
   (c) whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.
4. In addition to the requirements under section 3 a NSW DNSP, when assigning a customer to a tariff class, must ensure the following:
   (a) that customers with similar connection and usage profiles are treated equally
   (b) that customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities.

Reassignment of existing customers to another existing tariff during the next regulatory control period

5. If a NSW DNSP believes that an existing customer's load characteristics or connection characteristics (or both) have changed such that it is no longer appropriate for that customer to be assigned to the tariff class to which the customer is currently assigned or a customer no longer has the same or materially similar load or connection characteristics as other customers on the customer's existing tariff, then the DNSP may reassign that customer to another tariff class.
6. A NSW DNSP must notify the customer concerned in writing of the tariff class to which the customer has been re-assigned, prior to the reassignment occurring. The notice must include advice that the customer may request further information from the DNSP, may object to the proposed re-assignment and, if the customer objects to the proposed re-assignment and that objection is not resolved to the satisfaction of the customer, the customer or the DNSP may request the AER to decide which of the DNSP's tariff classes the customer should be assigned to.

7. If, in response to a notice issued in accordance with section 6, the relevant NSW DNSP receives a request for further information from a customer, the relevant NSW DNSP must provide such information. If any of the information requested by the customer is confidential then the relevant NSW DNSP is not required to provide that information to the customer.

8. If, in response to a notice issued in accordance with section 6, a customer makes an objection to the relevant NSW DNSP about the proposed re-assignment, the relevant NSW DNSP must reconsider the proposed re-assignment, taking into consideration the factors in section 3 above, and notify the customer in writing of its decision and the reasons for that decision.

9. If the AER receives a request in accordance with section 6, then it must decide which of the relevant NSW DNSP's tariff classes the customer should be assigned to, taking into account one or more of the following factors:

   (a) the nature and extent of the customer's usage

   (b) the nature of the customer's connection to the network

   (c) whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.

10. As soon as practicable after being requested to do so by the AER, the relevant NSW DNSP must provide to the AER a statement setting out which tariff class a particular customer or group of customers has been assigned to and the reasons for the relevant NSW DNSP's decision.

11. The AER must notify the customer and the relevant NSW DNSP in writing of its decision and the date from which its decision should be applied.

12. If the AER does not give a written notice under section 11 within 30 business days of receiving the relevant request under section 6 or within such further period that the AER may decide, then the AER is to be regarded as having decided that the customer giving the relevant request under section 6 should not be re-assigned.

13. The NSW DNSPs must comply with a decision by the AER under section 9 and 10 in relation to a customer.

System of assessment and review of the basis on which a customer is charged

14. Where the charging parameters for a particular tariff result in a basis of charge that varies according to the customer's usage or load profile, each NSW DNSP must set out in its pricing proposal a method of how it will review and assess the basis on which a customer is charged.

15. If the AER considers that the method provided under section 14 does not provide for an effective system of assessment and review of the basis on which a customer is charged, the AER may request additional information or request that the relevant NSW DNSP revise and resubmit a revised method.

16. If the AER considers the method provided in accordance with section 14 is reasonable it will approve that method by notice in writing to the relevant NSW DNSP.

Appendix B: Negotiable component criteria

National Electricity Objective

1. The terms and conditions of access for a negotiable component of a direct control service, including the price that is to be charged for the negotiable component and any access charges, should promote the achievement of the national electricity objective.

Criteria for terms and conditions of access

Terms and conditions of access

2. The terms and conditions of access for a negotiable component must be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER.
3. The terms and conditions of access for a negotiable component (including, in particular, any exclusions and limitations of liability and indemnities) must not be unreasonably onerous taking into account the allocation of risk between the DNSP and the other party, the price for the negotiable component and the costs to the DNSP of providing the negotiable component.
4. The terms and conditions of access for a negotiable component must take into account the need for the direct control service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER.

Price of Services

5. The price for a negotiable component must be the price for that component in the DNSP's approved pricing proposal, unless the terms and conditions sought for the component are so different from those used for the purposes of establishing the approved pricing proposal as to warrant determination of the price without regard to this criterion.
6. Subject to criterion 5, the price for a negotiable component must reflect the costs that the DNSP has incurred or incurs in providing that component, and must be determined in accordance with the principles and policies set out in the Cost Allocation Method.
7. Subject to criteria 5, 8 and 9, the price for a negotiable component must be at least equal to the cost that would be avoided by not providing it but no more than the cost of providing it on a stand alone basis.
8. Subject to criterion 5, if the direct control service of which the negotiable component is a component is the provision of a shared distribution service that:

   i. exceeds any network performance requirements which it is required to meet under any relevant electricity legislation; or

   ii. exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER, then the difference between the price for that direct control service and the price for the shared distribution service which meets network performance requirements must reflect the DNSP's incremental cost of providing that service (as appropriate).

9. Subject to criterion 5, if the direct control service of which the negotiable component is a component is the provision of a shared distribution service that does not meet or exceed the network performance requirements, the difference between the price for that service and the price for the shared distribution service which meets, but does not exceed, the network performance requirements should reflect the cost the DNSP would avoid by not providing that service (as appropriate).
10. Subject to criterion 5, the price for a negotiable component must be the same for all Distribution Network Users unless there is a material difference in the costs of providing the negotiable component to different Distribution Network Users or classes of Distribution Network Users.
11. Subject to criterion 5, the price for a negotiable component must be subject to adjustment over time to the extent that the assets used to provide the direct control service are subsequently used to provide services to another person, in which case such adjustment must reflect the extent to which the costs of those assets are being recovered through charges to that other person.
12. Subject to criterion 5, the price for a negotiable component must be such as to enable the DNSP to recover the efficient costs of complying with all regulatory obligations or requirements associated with the provision of the negotiable component.

Criteria for access charges

Access Charges

13. Any access charges must be based on costs reasonably incurred by the DNSP in providing distribution network user access and, in the case of compensation referred to in clause 5.5(f)(4)(ii) to (iii) of the NER, on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to in those provisions where an event referred to in those provisions occurs (as appropriate).

Appendix C: EnergyAustralia negotiated distribution service criteria

National Electricity Objective

1. The terms and conditions of access for an EnergyAustralia negotiated distribution service, including the price that is to be charged for the provision of that service and any access charges, should promote the achievement of the national electricity objective.

Criteria for terms and conditions of access

Terms and Conditions of Access

2. The terms and conditions of access for an EnergyAustralia negotiated distribution service must be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER.
3. The terms and conditions of access for an EnergyAustralia negotiated distribution service (including, in particular, any exclusions and limitations of liability and indemnities) must not be unreasonably onerous taking into account the allocation of risk between EnergyAustralia and the other party, the price for the negotiated distribution service and the costs to EnergyAustralia of providing the negotiated distribution service.
4. The terms and conditions of access for an EnergyAustralia negotiated distribution service must take into account the need for the service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER.

Price of Services

5. The price for an EnergyAustralia negotiated distribution service must reflect the costs that EnergyAustralia has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the Cost Allocation Method.
6. Subject to criteria 7 and 8, the price for an EnergyAustralia negotiated distribution service must be at least equal to the cost that would be avoided by not providing that service but no more than the cost of providing it on a stand alone basis.
7. If an EnergyAustralia negotiated distribution service is a shared distribution service that:
   i. exceeds any network performance requirements which it is required to meet under any relevant electricity legislation; or
   ii. exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER,

   then the difference between the price for that service and the price for the shared distribution service which meets network performance requirements must reflect EnergyAustralia's incremental cost of providing that service (as appropriate).

8. If an EnergyAustralia negotiated distribution service is the provision of a shared distribution service that does not meet or exceed the network performance requirements, the difference between the price for that service and the price for the shared distribution service which meets, but does not exceed, the network performance requirements should reflect the cost EnergyAustralia would avoid by not providing that service (as appropriate).

9. The price for an EnergyAustralia negotiated distribution service must be the same for all Distribution Network Users unless there is a material difference in the costs of providing the negotiated distribution service to different Distribution Network Users or classes of Distribution Network Users.

10. The price for an EnergyAustralia negotiated distribution service must be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person, in which case such adjustment must reflect the extent to which the costs of that asset are being recovered through charges to that other person.

11. The price for an EnergyAustralia negotiated distribution service must be such as to enable EnergyAustralia to recover the efficient costs of complying with all regulatory obligations or requirements associated with the provision of the negotiated distribution service.

Criteria for access charges

Access Charges

12. Any access charges must be based on costs reasonably incurred by EnergyAustralia in providing distribution network user access and, in the case of compensation referred to in clauses 5.4A(h) to (j) of the NER, on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to in those provisions where an event referred to in those provisions occurs (as appropriate).

Appendix D: Country Energy negotiating framework

Country Energy Negotiating Framework

Country Energy Negotiating Framework for Negotiable Components

1. Introduction

1.1 Purpose of this Negotiating Framework

This document sets out the minimum requirements to be followed during negotiations between Country Energy and any person (***Service Applicant)*** who wishes to receive a *direct control service* from Country Energy for the purpose of the *2009 regulatory control period* that is determined by the AER to have one or more components that are negotiable components under clause 6.7A(a) of the Rules.

1.2 What is a "negotiable component"?

A negotiable component may be a particular component of a *direct control service* provided by Country Energy or may relate to the terms or conditions on which a *direct control service* or a component of a *direct control service* is to be provided by Country Energy.

A *direct control service* is a *distribution service* that is a direct control network service within the meaning of section 2B of the National Electricity Law.

1.3 *Contestable* Services

Contestable services are not covered by this Negotiating Framework. They are services which, under New South Wales law, can be provided by more than one Accredited Service Provider as a contestable service or on a competitive basis.

1.4 Terms and condition of access

The *terms and condition of access* for a negotiable component:

(1) are to be fair and reasonable and consistent with the safe and reliable operation of the *power system* in accordance with the Rules and the process for negotiable components. The price for a negotiable component is to be treated as being fair and reasonable where it complies with the principles in 6.7A.1(1)-(8);

(2) must not be unreasonably onerous taking into account the allocation of risk and the cost of providing the negotiable component; and

(3) should take into account the need for the *direct control service* to be provided in a manner that does not adversely affect the *power system*.

2. Charges

2.1 Any *access charges* to be imposed by Country Energy will be based on the costs reasonably incurred in providing *distribution network user access*, and in the case of compensation referred to in clause 5.5(f)(4)(ii) and (iii), on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to those provisions where an event in those provisions occurs.

3. Basis for Negotiation

3.1 Country Energy to comply with Negotiating Framework

Country Energy will comply with this Negotiating Framework when negotiating with *Service Applicants* in relation to a negotiable component in accordance with its obligations under the Rules.

3.2 *Service Applicant* to comply with Negotiating Framework

Service Applicants are required by the Rules to comply with this Negotiating Framework when negotiating with Country Energy in relation to a negotiable component.

3.3 Good Faith Negotiations

Country Energy and each *Service Applicant* that initiates a negotiation under this Negotiating Framework agree to conduct that negotiation in good faith.

3.4 Authority

(1) A *Service Applicant* that initiates a negotiation under this Negotiating Framework must nominate a person that has authority to represent the *Service Applicant* in the negotiations and provide Country Energy with contact details for that person. If the *Service Applicant* comprises more than one entity (e.g. a partnership or joint venture) the nominated person must have authority to represent all of the relevant entities.

(2) Country Energy will, in respect of each negotiation initiated under this Negotiating Framework, nominate a person that has authority to represent Country Energy in the negotiations and provide the *Service Applicant* with contact details for that person.

4. Connection to Country Energy's Network

4.1 This Negotiating Framework does not replace the process set out in the *Rules* for making an application to establish or modify a *connection*. However, in some cases the negotiations to which this Negotiating Framework applies may occur in the context of such an application.

4.2 The process for establishing or modifying a connection is set out in clause 5.3 of the *Rules* and comprises five basic steps:

(1) a *connection* enquiry made by the *Connection Applicant*;

(2) the initial response by the *Local Network Service Provider*;

(3) a *connection* application made by the *Connection Applicant*;

(4) an offer made by the *Local Network Service Provider*; and

(5) finalisation of a *connection agreement* between the *Connection Applicant* and *Local Network Service Provider*.

4.3 Country Energy envisages that a *Connection Applicant* would identify any negotiation it wished to conduct under this Negotiating Framework as part of its *connection* enquiry and initiate the process for any such negotiation at the stage of making a connection application. The offer to be made by Country Energy pursuant to clause 5.3.6 of the Rules to a *Connection Applicant* would then include the preliminary offer to be made as part of this Negotiating Framework, and the agreement to be entered into by the parties under clause 5.3.7 of the Rules would reflect the outcome negotiated pursuant to this Negotiating Framework.

4.4 Country Energy's document "Customer Funded Connections & Connection Related Services" is located on Country Energy's website at: http://www.countryenergy.com.au/internet/cewebpub.nsf/AttachmentsByTitle/Customer_Funded_Connections_July_2007.pdf/$FILE/Customer_Funded_Connections_July_2007.pdf. The document contains Country Energy's general conditions for customer funded services which include customer connection services, connection works and customer funded network augmentations.

4.5 When Country Energy is providing a *Service Applicant* a preliminary response under section 5.2 of this Framework, Country Energy will, if appropriate, provide the *Service Applicant* with a copy of Country Energy's Agreement in Relation to Connection Investigation (**Agreement**).

4.6 The Agreement relates to the services Country Energy provides to a *Service Applicant* as part of the connection application process.

4.7 Country Energy is not required to take any further action under this Negotiating Framework until the *Service Applicant* has executed the Agreement.

5. Process for Negotiation

5.1 Initiation of process by *Service Applicant*

(1) The process set out in this Negotiating Framework will be initiated when a *Service Applicant*, having lodged a Rules compliant *connection* enquiry with Country Energy, provides a written request to Country Energy to conduct a negotiation under this Negotiating Framework.

(2) The request must identify the type, magnitude and timing of the proposed *connection* to Country Energy's *network*.

5.2 Preliminary response and request for information by Country Energy

(1) When Country Energy receives a written request from a *Service Applicant* to conduct a negotiation under this Negotiating Framework, Country Energy will provide a preliminary response to the *Service Applicant*. The preliminary response will include:

(a) a list of the information that Country Energy would like the *Service Applicant* to provide to Country Energy for the purpose of the negotiation. The nature of the information that Country Energy may request the *Service Applicant* to provide is described in section 6.2 of this Negotiating Framework and includes the information the *Service Applicant* is required to provide under the relevant schedules in chapter 5 of the Rules;

(b) an estimate of the fees that Country Energy is entitled to charge pursuant to the Rules to cover its reasonable direct expenses of processing the request (which may include the cost of providing information under section 6.1 of this Negotiating Framework) and the date the fees must be paid. Country Energy may provide the *Service Applicant* with revised estimates of the fee from time to time;

(c) if appropriate, a copy of Country Energy's standard Agreement; and

(d) where negotiations relate to a *connection* application, a copy of Country Energy's standard form negotiated *connection agreement*.

(2) Country Energy will provide this preliminary response to the *Service Applicant* in writing and will use its reasonable endeavours to do so within 10 business days of receiving the initial written request from the *Service Applicant*.

5.3 Request for information by Service Applicant

(1) The *Service Applicant* must provide Country Energy with a written request for, and a list of, the information that the *Service Applicant* would like Country Energy to provide to the *Service Applicant* for the purpose of the negotiation. The nature of the information that the *Service Applicant* may request Country Energy to provide is described in section 6.1 below.

(2) The *Service Applicant* must use its reasonable endeavours to provide this information request within 20 business days of receiving the preliminary response from Country Energy.

6. Exchange of information

6.1 Provision of information by Country Energy

(1) Country Energy must provide all such commercial information as the *Service Applicant* may reasonably require to enable the *Service Applicant* to engage in effective negotiation with Country Energy for the provision of the negotiable component.

(2) Country Energy must:

(a) identify and inform the *Service Applicant* of the reasonable costs and/or the cost increase or decrease in costs (as appropriate) of providing the negotiable component; and

(b) demonstrate to the *Service Applicant* that its charges for providing those negotiable components reflect those costs and/or the cost increment or decrement (as appropriate); and

(c) have appropriate arrangements for assessment and review of the charges and the basis on which they are made.

(3) To the extent possible, Country Energy must provide the information in writing to the *Service Applicant*.

(4) Country Energy will use its reasonable endeavours to provide the information within 20 business days of the later of the following dates:

(a) the date on which Country Energy receives the information request from the *Service Applicant*; or

(b) the date on which the *Service Applicant* executes the Agreement.

(5) If Country Energy believes that the timeframe set out in section 6.1(4) is not an achievable timeframe, the parties must negotiate in good faith to agree an achievable timeframe.

6.2 Provision of information by the *Service Applicant*

(1) The *Service Applicant* must provide all such commercial information as Country Energy may reasonably require to enable Country Energy to engage in effective negotiation with the *Service Applicant* for the provision of a negotiable component.

(2) To the extent possible, the *Service Applicant* must provide the information in writing to Country Energy.

(3) The *Service Applicant* must use its reasonable endeavours to provide the information within 20 business days of receiving the preliminary response from Country Energy.

(4) If the *Service Applicant* believes that the timeframe set out in section 6.2(3) is not an achievable timeframe, the parties must negotiate in good faith to agree an achievable timeframe.

6.3 Additional information or clarification

(1) Either party may request additional information from, or clarification of information that has been provided by, the other party.

(2) The parties will negotiate in good faith to provide this additional information or clarification to the other party within a reasonable timeframe.

7. Other Distribution Network Users

7.1 Country Energy must determine the potential impact on other *Distribution Network Users* of the provision of the negotiable component to the *Service Applicant*.

7.2 Country Energy must notify and consult with any affected *Distribution Network Users* and ensure that the provision of these negotiable components does not result in non-compliance with obligations in relation to other *Distribution Network Users* under the Rules.

7.3 Country Energy will start any relevant consultation process as soon as it has received sufficient information from the *Service Applicant* to enable it to proceed. Country Energy will use its reasonable endeavours to progress and complete the consultation process at the earliest practicable date.

7.4 Country Energy will keep the *Service Applicant* under this Negotiating Framework informed of the progress of any such consultation process.

8. Application for Connection

8.1 The *Service Applicant* will provide Country Energy with an *application to connect* in accordance with clauses 5.3.4 and 5.3.4A of the Rules.

8.2 Country Energy may refuse to accept an *application to connect* from the *Service Applicant* unless it is provided in accordance with clauses 5.3.4 and 5.3.4A of the Rules.

9. Offer and Negotiating Timetable

9.1 Offer

(1) Country Energy will undertake an initial assessment of the request and the information provided by the *Service Applicant* under sections 6.2 and 8.1 and advise the *Service Applicant* in writing of Country Energy's expected timeframe for making an offer.

(2) Country Energy will use its reasonable endeavours to provide an offer (in writing) within the notified timeframe, or in any event within 120 business days from its receipt of a written request from the *Service Applicant* to negotiate under this Negotiating Framework.

9.2 Negotiating Timetable

(1) Once Country Energy has provided an offer to the *Service Applicant*, Country Energy and the *Service Applicant* must hold an initial meeting to discuss that offer and, if necessary, the timetable for conducting negotiations in relation to that offer.

(2) The parties must use their reasonable endeavours to hold the initial meeting within 10 business days of the *Service Applicant* receiving the offer from Country Energy.

(3) If desired by either Country Energy or the *Service Applicant*, the parties must seek to establish a timetable for meetings and responses with a view to entering into a *connection agreement* within a reasonable period which is acceptable to each of them.

(4) Unless otherwise negotiated and agreed by the parties under section 9.2(3) the parties will use their reasonable endeavours to finalise negotiations within 160 business days from the date Country Energy receives a written request from the *Service Applicant* to negotiate under this negotiating Framework.

9.3 Negotiation

Each of Country Energy and the *Service Applicant* must use its reasonable endeavours to adhere to the timetable established for the negotiation (if any) and to progress the negotiation expeditiously and in good faith.

9.4 Indicative timetable

Unless otherwise negotiated and agreed by the parties, Country Energy proposes a timeframe for progressing and finalising negotiations for the provision of negotiable components at Table 1, Attachment 1. This timetable may be adopted or modified by agreement of the parties.

10. Confidential Information

10.1 For the avoidance of doubt, commercial information which is required to be provided by Country Energy to a *Service Applicant* in accordance with clause 6.1(1):

(1) does not include *confidential information* provided to Country Energy by another person; and

(2) may be provided subject to a condition that the *Service Applicant* must not provide any part of that commercial information to any other person without the consent of Country Energy.

10.2 For the avoidance of doubt, commercial information which is required to be provided by a *Service Applicant* to Country Energy in accordance with clause 6.2(1):

(1) does not include *confidential information* provided to the *Service Applicant* by another person; and

(2) may be provided subject to a condition that Country Energy must not provide any part of that commercial information to any other person without the consent of the relevant *Service Applicant*.

11. Dispute Resolution

11.1 Any disputes between Country Energy and the *Service Applicant* as to the *terms and conditions of access* for the provision of a negotiable component are to be dealt with in accordance with relevant provisions of the National Electricity Law and the *Rules* for dispute resolution.

12. Publication

12.1 Country Energy will publish the outcome of the negotiation to provide negotiable components on its website.

13. Costs

13.1 The *Service Applicant* must pay Country Energy's reasonable direct expenses incurred in processing the application to provide a negotiable component.

14. Termination of Negotiation

14.1 *Service Applicant* may terminate negotiation

(1) A *Service Applicant* that has initiated a negotiation under this Negotiating Framework may, at any stage, elect not to continue with the negotiation.

(2) The *Service Applicant* must confirm its decision to terminate a negotiation in writing to Country Energy as soon as practicable after electing not to continue with the negotiation.

14.2 Country Energy may terminate negotiation

(1) Country Energy may terminate a negotiation under this Negotiation Framework where:

(a) either party has exercised its rights to terminate the Agreement;

(b) Country Energy believes, on reasonable grounds, that the *Service Applicant* is not conducting the negotiation under this Negotiation Framework in good faith;

(c) the *Service Applicant* consistently fails to comply with the requirements of this Negotiation Framework; or

(d) the *Service Applicant* has failed to comply with an obligation in this Negotiation Framework to use its reasonable endeavours to undertake or complete an action within a specified or agreed timeframe, and does not complete the relevant action within 20 business days of a written request from Country Energy.

(2) Country Energy must inform the *Service Applicant* in writing of its decision to terminate a negotiation.

15. Agreement reached as a result of negotiation

15.1 If the parties reach an agreed position as a result of a negotiation under this Negotiation Framework, that *connection agreement* will not take effect until it is recorded in writing and signed by both parties.

16. Interpretation of this Negotiating Framework

16.1 Defined Terms

(1) The references in this Negotiating Framework to the "National Electricity Rules" or the "Rules" are references to the "Rules" as defined in the National Electricity (New South Wales) Act 1997.

(2) Terms in italic have the same meaning given to them by the Rules.

(3) A word or phrase defined in the Agreement in Relation to Connection Investigation (**Agreement**) has the same meaning in this Negotiating Framework.

16.2 Rules of Interpretation

The rules of interpretation set out in the Agreement apply to this Negotiating Framework.

16.3 Departures from this Negotiation Framework

(1) Subject to the parties' obligations under the Rules, the parties may agree to depart from any specific aspect of this Negotiation Framework.

(2) Any such agreement must be recorded in writing and signed by both parties and must identify which aspect of the Negotiation Framework the parties are departing from and which aspects continue to apply.

(3) In the event of any inconsistency between this Negotiating Framework and any of the requirements of Rules 5.3 and 5.5 and other relevant provisions of Chapter 6 of the Rules, those requirements prevail.

17. Notices

17.1 All communication provided in writing by a *Service Applicant* pursuant to this Negotiating Framework must be delivered to P.O. Box 718, Queanbeyan, News South Wales, 2620 unless the Applicant is otherwise directed by Country Energy.

Attachment 1

Table 1 provides an indicative timeframe for provision of information, negotiation and finalisation of negotiations for a negotiable component. Country Energy and the *Service Applicant* must use all reasonable endeavours to adhere to this timetable unless otherwise agreed between the parties.

Table 1

	Event	Indicative timeframe
Receipt date	*Service Applicant* provides a written request to conduct a negotiation under this Framework	
Preliminary response	Country Energy to provide a preliminary response to the *Service Applicant*	Receipt date + 10 business days
Service Applicant request	*Service Applicant* to provide a request for information to Country Energy for the purpose of this negotiation	Preliminary response + 20 business days
Country Energy response	Country Energy to provide information to the *Service Applicant* on costs, charges and review arrangements, and all other information required for negotiation	20 business days from the later of: (i) *Service Applicant* request; or (ii) execution of Agreement.
Negotiation information	*Service Applicant* to provide Country Energy with all commerical information required for effective negotiation	Preliminary response + 20 business days
Offer	Offer to be sent by Country Energy to the *Service Applicant*	Receipt date + 120 business days
Initial meeting	Parties to hold an initial meeting and establish a timetable for conducting negotiations	Offer + 10 business days
Final agreement	Parties to finalise agreement	Receipt date + 160 business days

Appendix E: EnergyAustralia negotiating framework

EnergyAustralia™

ATTACHMENT 5.1

Proposed Negotiating Framework for
Negotiated Distribution Services AND
Negotiable Components of Direct Control
Services
1 July 2009 to 20 June 2014

June 2008

REVIEW

Responsibility	Name	Date
Author	J Smith	22 May 2008
Reviewer		

Approval	Name	Signature	Date
EM-NR&P	H. Colebourn		22 May 2008

Background

A. The Transitional Rules set out in Chapter 11 and Appendix 1 to the National Electricity Rules (the Transitional Rules") provide that:

(a) EnergyAustralia must prepare a document setting out the procedure to be followed during negotiations between it and any person who wishes to receive a Negotiated Distribution Service as to the terms and conditions of access for the provision of the service (Transitional Rules Part D Clause 6.7.5(a));

(b) A Distribution Network Service Provider must prepare a document setting out the procedure to be followed during negotiations between it and any person who wishes to be provided with a negotiable component of a direct control service as to the terms and conditions of access for the provision of the service (Transitional Rules Part DA Clause 6.7.5(a));

(c) the negotiating frameworks required by the Transitional Rules must comply with and be consistent with the applicable requirements of a distribution determination applying to the provider; and

(d) the negotiating frameworks must comply with and be consistent with the

applicable requirements of Part D clause 6.7.5(c) and Part DA clause 6.7A.5(c), which sets out the minimum requirements for a negotiating framework.

(e) EnergyAustralia may prepare and submit a document that combines both negotiating frameworks into a single framework (Part DA clause 6.7.A5(f)).

B. This document has been prepared in fulfilment of EnergyAustralia's obligations under Transitional Rules Part D Clause 6.7.5(a) and Part DA Clause 6.7A.5(a) to establish negotiating frameworks.

C. This document applies to EnergyAustralia and any Service Applicant who applies to receive a Negotiated Distribution Service or a negotiable component of a direct control service.

D. As at 2 June 2008 an EnergyAustralia Negotiated Distribution Service is a service that is provided by EnergyAustralia by means of, or in connection with, the EnergyAustralia transmission support network and that would otherwise be classified as a negotiated transmission service (Transitional Rules 6.1.6(d)).

E. As at 1 July 2009 a Negotiable Component of a Direct Control Service is a component of a direct control service that is provided by EnergyAustralia and that has been determined by the AER to be a negotiable component of a direct control service under a distribution determination.

EnergyAustralia's Negotiating Framework

1 Application of negotiating framework

1.1 This negotiating framework applies to EnergyAustralia and each Service Applicant who has made an application in writing to EnergyAustralia for the provision of either a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service.

1.2 EnergyAustralia and any Service Applicant who wishes to receive a Negotiated Distribution Service or a Negotiable Component of a Direct Control S ervice from EnergyAustralia must comply with the requirements of this negotiating framework.

1.3 The requirements set out in this negotiating framework are additional to any requirements or obligations contained in Clauses 5.3, 5.4A and 5.5 and Chapter 6A of the National Electricity Rules (NER) or in the Transitional Rules. In the event of any inconsistency between this negotiating framework and any other requirements in the NER, the requirements of the NER will prevail.

1.4 Nothing in this negotiating framework or in the NER will be taken as imposing an obligation on EnergyAustralia to provide any service to the Service Applica nt.

2 Obligation to negotiate in good faith

2.1 EnergyAustralia and the Service Applicant must negotiate in good faith the terms and conditions of access for the provision by EnergyAustralia of the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service sought by the Service Applicant.

3 Timeframe for commencing, progressing and finalising negotiations

3.1 Clause 3.4 and Table 1 set out the timeframe for commencing, progressing and finalising negotiations in relation to applicat ions for a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service.

3.2 The timeframe set out in Table 1 will not apply where a timeframe is specified in Chapter 5 in relation to any application for negotiated distribution serv ices, and in that case the time period specified in Chapter 5 will apply.

3.3 The timeframe set out in clause 3.4 may be suspended in accordance with clause 9.

3.4 Timeframes:

(a) The specified time for commencing, progressing and finalising negotiations with a Service Applicant is as set out in Table 1.

(b) EnergyAustralia and the Service Applicant shall use reasonable endeavours to adhere to the time periods specified in Table 1 and may by agreement extend any such time period.

(c) The preliminary program finalised under C in Table 1 may be modified from time to time by agreement of the parties, where such agreement must not be unreasonably withheld. Any such amendment to the preliminary program shall be taken to be a reasonable period of time for commencing, progress ing and finalising negotiations with a Service Applicant for the provision of the Negotiated Distribution Service or the Negotiable Component of a Standard Control Service. The requirement in (clause 3.3(b) applies to the last amended preliminary program.

Table 1

	Event	Indicative timeframe
A.	Receipt of written application for a Negotiated Distribution Service or Negotiable Component of a direct control service. The application must be made by either: Completing an Application Form in accordance with EnergyAustralia publications *ES 1-Customer Connection Information* or *ES 10-Requirements for Electricity Connections to Developments* (where the service requested relates to services provided under EnergyAustralia's Standard Form Customer Connection Contract) or Making a connection inquiry, where an application is being made to establish or modify a connection under Chapter 5 of the National Electricity Rules	X
B.	Parties meet to discuss a preliminary negotiation programme with milestones that represent a reasonable period of time for commencing, progressing and finalising negotiations.	X + 15 business days
C.	Parties finalise negotiation programme, which may include, without limitation, milestones relating to: ▪ the provision of information by Energy Australia to meet the obligation in clause 5.1. ▪ the request and provision of commercial information by EnergyAustralia and the Service Applicant, see clauses 4 and 5; and ▪ notification and consultation with any affected Distribution Network Users, see clause 6. ▪ The Negotiable Component or Negotiable Distribution Service being formally specified by the Service Applicant ▪ The notification by EnergyAustralia of its reasonable direct expenses incurred in processing the application and the payment of those expenses by the service applicant, see clause 9.	X + 30 business days
D	Parties progress negotiations and the Service Applicant specifies to EnergyAustralia the exact Negotiable Distribution Service or Negotiable Component of a direct control service which is required to be provided.	X + 40 business days
E	Parties finalise negotiations	X + 60 business days or (where the reasonable direct expenses of EnergyAustralia have been requested but not paid by the service applicant) within 20 business days of those expenses being paid to EnergyAustralia.

4 Provision of Commercial Information by Service Applicant

4.1 EnergyAustralia may give notice to the Service Applicant requesting Commercial Information held by the Service Applicant that is reasonably required b y EnergyAustralia to enable it to engage in effective negotiations with the Service Applicant in relation to the application and to enable EnergyAustralia to submit Commercial Information to the Service Applicant.

4.2 Subject to clauses 4.3 and 4.4, the Ser vice Applicant must use its reasonable endeavours to provide EnergyAustralia with the Commercial Information requested by EnergyAustralia in accordance with clause 4.1 within 10 Business Days of that request, or within a time period as agreed by the partie s.

4.3 Confidentiality Requirements - Commercial Information

4.4 For the purposes of this clause 4, Commercial Information does not include:

(a) confidential information provided to the Service Applicant by another person; or

(b) information that the Service Ap plicant is prohibited, by law, from disclosing to EnergyAustralia.

4.5 Commercial Information may be provided by the Service Applicant subject to conditions including the condition that EnergyAustralia must not disclose the Commercial Information to any other person unless the Service Applicant consents in writing to the disclosure. The Service Applicant may require EnergyAustralia to enter into a confidentiality agreement, on terms reasonably acceptable to both parties, with the Service Applicant in respect of any Commercial Information provided to EnergyAustralia.

4.6 A consent provided by the Service Applica nt in accordance with clause 4.5 may be subject to the condition that the person to whom EnergyAustralia discloses the Commercial Information must enter into a separate confidentiality agreement with the Service Applicant.

5 Provision of Commercial Information by EnergyAustralia

5.1 EnergyAustralia must provide the following information to the Service Applicant in accordance with the negotiation programme prepared in accordance with clause 3.4:

(a) the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service to the Service Applicant;

(b) a demonstration to the Service Applicant that the proposed charges for providing the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service reflect those costs and/or the cost increment or decrement (as appropriate); and

(c) EnergyAustralia's arrangements for the assessment and review of the charges and the basis upon which they are made.

5.2 The Service Applicant may give a notice to EnergyAustralia requesting that EnergyAustralia provide it with all Commercial Information held by Energ yAustralia that is reasonably required by the Service Applicant to enable it to engage in effective negotiations with EnergyAustralia for the provision of a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service , including the following:

(a) a description of the nature of the Negotiated Distribution Service or a Negotiable Component of a Direct Control Service including what EnergyAustralia would provide to the Service Applicant as part of that service;

(b) the terms and conditions on which EnergyAustralia would provide th e Negotiated Distribution Service or the Negotiable Component of a Direct Control

Service to the Service Applicant if not previously provided in accordance with subclause 5.1(a);

(c) the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service to the Service Applicant if not previously provided in accordance with subclause 5.1(b);

(d) a demonstration to the Service Applicant that the proposed charges for providing the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service reflect those costs and/or the cost increment or decrement (as appropriate); and

(e) EnergyAustralia's proposed arrangements for the assessment and review of the proposed charges for the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service and the basis upon which those charges are made if not previously provided in accordance with subclause 5.1(c).

Confidentiality Requirements

5.3 For the purposes of clause 5.1, Commercial Information does not include:

(a) confidential information provided to EnergyAustralia by another person; or

(b) information that EnergyAustralia is prohibited, by law, from disclosing to the Service Applicant.

5.4 EnergyAustralia may provide the Commercial Information in accordance with clause 5.2 subject to relevant conditions including the condition that the Service Applicant must not disclose the Commercial Information to any other person unless EnergyAustralia consents in writing to the disclosure. EnergyAustralia may require the Service Applicant to enter into a confidentiality agreement with EnergyAustralia, on terms reasonably acceptable to both parties, in respect of Commercial Information provided to the Service Applicant.

5.5 A consent provided to a Service Applicant in accordance with clause 5.4 may be subject to the condition that the person to whom the Service Applicant discloses the Commercial Information must enter into a separate confidentiality agreement with EnergyAustralia.

6 Assessment and Review of Charges and Basis of Charges

6.1 EnergyAustralia's must have arrangements for the assessment and review of the proposed charges for the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service and the basis upon which those charges are made.

6.2 EnergyAustralia must provide these arrangements to the Service Applicant in accordance with clause 5.1 or 5.2 as applicable.

7 Determination of impact on other Distribution Network Users and consultation with affected Distribution Network Users

7.1 EnergyAustralia must determine the potential impact on Distribution Network Users, other than the Service Applicant, of the provision of the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service.

7.2 EnergyAustralia must notify and consult with any affected Distribution Network Users and ensure that the provision of the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service does not result in non-compliance with obligations to other Distribution Network Users under the NER.

8 Suspension of Timeframe for Provision of a Negotiated Distribution Service or a Negotiable Component of a D irect Control Service

8.1 The timeframes for negotiation of provision of a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service in Table 1, or as otherwise agreed between the parties, are suspended if:

(a) a dispute in relation to the Negotiated Distribution Service or a Negotiable Component of a Direct Control Service has been notified to the AER under Part 10 of the NEL, from the date of notification of that dispute to the AER until

(i) the withdrawal of the dispute under section 126 of the NEL;

(i) the termination of the dispute by the AER under section 131 or 132 of the NEL; or

(i) determination of the dispute by the AER under section 128 of the NEL;

(b) within 15 Business Days of EnergyAustralia requesting additional Commercial Information from the Service Applicant pursuant to clause 4, the Service Applicant has not supplied that Commercial Information;

(c) without limiting clauses 8.1(a) and (b), either of the parties does not promptly conform with any of its obligations as required b y this negotiating framework or as otherwise agreed by the parties;

(d) EnergyAustralia has been required to notify and consult with any affected Distribution Network Users under clause 6, from the date of notification to the affected Distribution Network Users until the end of the time limit specified by EnergyAustralia for any affected Distribution Network Users, or the receipt of such information from the affected Distribution Network Users whichever is the later regarding the provision of the Negotiated Distribution Service or Negotiable Component of a Direct Control Service.

(e) Each party will notify the other party if it considers that the timeframe has been suspended, within 5 business days of that suspension.

9 Dispute Resolution

9.1 All disputes between the parties as to the terms and conditions of access for the provision of a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service are to be dealt with by the AER in accordance with Part 10 of the NEL and Part L of the Transitional Rules

10 Payment of EnergyAustralia's Reasonable Costs

10.1 EnergyAustralia may give the Service Applicant a notice setting out EnergyAustralia's reasonable direct expenses incurred in the processing of the service applicants application.

10.2 The service applicant must, within 20 days of a notice being given i n accordance with this clause 9 pay to EnergyAustralia the amount set out in the Notice.

11 Termination of Negotiations

11.1 The Service Applicant may elect not to continue with its application for a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service and may terminate the negotiations by giving EnergyAustralia written notice of its decision to do so.

11.2 EnergyAustralia may terminate a negotiation under this framework by giving the Service Applicant written notice of its decision to do so where:

(a) EnergyAustralia believes on reasonable grounds that the Service Applicant is not conducting the negotiation under this negotiating framework in good faith;

(b) the Service Applicant consistently fails to comply with the requirements of the negotiating framework;

(c) the Service Applicant fails to comply with an obligation in this negotiating framework to undertake or complete an action within a specified or agreed timeframe, and does not complete the relevant action within 20 Business Days of a written request from EnergyAustralia;

(d) An act of Solvency Default occurs in relation to the Service Applicant.

12 Publication of Results of Negotiations on Website

12.1 EnergyAustralia will publish the outcomes of negotiations for Negotiated Distribution Services and Negotiable Components of Direct Control Services on its website .

13 Giving notices

13.1 A notice, consent, information, application or request that must or may be given or made to a party under this document is only given or made if it is in writing and delivered or posted to that party at its address set out below.

13.2 If a party gives the other party 3 Business Days' notice of a change of its address, a notice, consent, information, application or request is only given or made by that other party if it is delivered or posted to the latest address.

EnergyAustralia	
Name:	EnergyAustralia
Address:	GPO Box 4009, Sydney, NSW 2001 Attention: Network Connections
Service Applicant Name	
Name:	Service Applicant
Address:	The nominated address of the Service Applicant provided in writing to EnergyAustralia as part of the application

Time notice is given

13.3 A notice, consent, information, application or request is to be treated as giv en or made at the following time:

(a) if it is delivered, when it is left at the relevant address; or

(b) if it is sent by post, 2 Business Days after it is posted.

(c) If sent by facsimile transmission, on the day the transmission is sent (but only if the sender has a confirmation report specifying a facsimile number of the recipient, the number of pages sent and the date of transmission) .

13.4 If a notice, consent, information, application or request is delivered after the normal business hours of the party to whom it is sent, it is to be treated as having been given or made at the beginning of the next Business Day.

14 Miscellaneous

Governing law and jurisdiction

14.1 This document is governed by the law of the State of New South Wales.

14.2 The parties submit to the non-exclusive jurisdiction of the courts of the state of New South Wales.

14.3 The parties will not object to the exercise of judgment by the courts of the State of New South Wales on any basis.

Severability

14.4 If a clause or part of a clause of this negotiating framework can be read in a way that makes it illegal, unenforceable or invalid, but can also be read in a way that makes is legal, enforceable and valid, it must be read in the latter way.

14.5 If any clause or part of a clause is illegal, unenforceable or inv alid, that clause or part is to be treated as removed from this negotiating framework, but the rest of this negotiating framework is not affected.

Time for Action

14.6 If the day on or by which something is required to be done or may be done is not a Business Day, that thing must be done on or by the next Business Day.

15 Definitions and interpretation

15.1 Definitions

In this document the following definitions apply:

Business Day means a day on which all banks are open for business generally in Sydney, NSW.

Commercial Information shall include at a minimum, the following classes of information:

In relation to a Service Applicant, details of corporate structure, financial details relevant to creditworthiness and commercial risk and ownership of assets;

technical information relevant to the application for a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service;

financial information relevant to the application for a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service;

details of an application's compliance with any law, standard, NER or guideline.

Costs means any costs or expenses incurred by EnergyAustralia in complying with this negotiating framework or otherwise advancing the Servic e Applicant's request for the provision of a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service or such other costs or expenses consistent with the NER, EnergyAustralia's Cost Allocation Methodology or any relevant part o f a distribution determination applying to EnergyAustralia.

EnergyAustralia means EnergyAustralia ABN 67505337385

Solvency Default means the occurrence of any of the following events in relation to the Service Applicant:

(a) An originating process or application for the winding up of the Service

Applicant (other than a frivolous or vexatious application) is filed in a court or a special resolution is passed to wind up the Service Applicant, and is not dismissed before the expiration of 60 days from s ervice on the Service Applicant;

(b) A receiver, receiver and manager or administrator is appointed in

respect of all or any part of the assets of the Service Applicant, or a provisional liquidator is appointed to the Service Applicant;

(c) A mortgagee, chargee or other holder of security, by itself or by or

through an agent, enters into possession of all or any part of the assets of the Service Applicant;

(d) A mortgage, charge or other security is enforced by its holder or becomes enforceable or can become enforceable with the giving of notice, lapse of time or fulfilment of a condition;

(e) The Service Applicant stops payment of, or admits in writing its inability to pay, its debts as they fall due;

(f) The Service Applicant applies for, consents to, or acquiesces in the appointment of a trustee or receiver of the Service Applicant or any of its property;

(g) A court appoints a liquidator, provisional liquidator, receiver or trustee, whether permanent or temporary, of all or any part of the Service Applicant's property;

(h) The Service Applicant takes any step to obtain protection or is granted protection from its creditors under any applicable legislation or a meeting is convened or a resolution is passed to appoint an administrator or controller (as defined in the Corporations Act 2001), in respect of the Service Applicant;

(i) A controller (as defined in the Corporations Act 2001) is appointed in respect of any part of the property of the Service Applicant;

j) Except to reconstruct or amalgamate while solvent, the Service Applicant enters into or resolves to enter into a scheme of arrangement, compromise or reconstruction proposed with its creditors (or any class of them) or with its members (or any class of them) or proposes re-organisation, re-arrangement moratorium or other administration of the Service Applicant's affairs;

(k) The Service Applicant is the subject of an event described in section 459C(2)(b) of the Corporations Act 2001; or

(l) Anything analogous or having a substantially similar effect to any of the events specified above happens in relation to the Service Applicant.

15.2 Interpretation

In this document, unless the context otherwise requires:

(a) terms defined in the NEL and the NER have the same meaning in this negotiating framework;

(b) a reference to any law or legislation or legislative provision includes any statutory modification, amendment or re-enactment, and any subordinate legislation or regulations issued under that legislation or legislative provision;

(c) a reference to any agreement or document is to that agreement or document as amended, novated, supplemented or replaced from time to time;

(d) a reference to a clause, part, schedule or attachment is a reference to a clause, part, schedule or attachment of or to this document unless otherwise stated;

(e) an expression importing a natural person includes any company, trust, partnership, joint venture, association, corporation, body corporate or governmental agency; and

(f) a covenant or agreement on the part of two or more persons binds them jointly and severally.

Appendix F: Integral Energy negotiating framework

Appendix H
Integral Energy's proposed negotiating framework

The Transitional Rules recognise that customers may require a service that is a *direct control service* but which has components that are more appropriately negotiated. To facilitate fair negotiation between the DNSP and customers for those components, the Transitional Rules require a DNSP to provide a basis for negotiating in the *negotiating framework*.

This Appendix summarises the key requirements of the Transitional Rules that relate to the *negotiating framework*. It indicates which components of Integral Energy's *direct control services* Integral Energy proposes to be Negotiable Components for the *2009 regulatory control period* and sets out Integral Energy's proposed *negotiating framework*.

1.1 Summary

Integral Energy offers *direct control services* to its customers. The Transitional Rules provide the option to provide customers with tailored *direct control services* to take account of their specific needs during the *2009 regulatory control period*. Integral Energy believes that customers may wish to take advantage of the opportunity during that period. Therefore, in accordance with the Transitional Rules, Integral Energy has set out the proposed Negotiable Components and a *negotiating framework* for those services.

1.2 Regulatory information requirements

The Transitional Rules requirements are summarised in Box 19.1.

Box 19.1: Negotiating framework regulatory information requirements
Part DA of the Transitional Rules deals with Negotiable Components for *direct control services*.
Clause 6.7A of the Transitional Rules allows the AER to determine that some components of *direct control services* are Negotiable Components.
Clause 6.7A.1 of the Transitional Rules sets out the principles relating to access to negotiable components.
Clause 6.7A.5 of the Transitional Rules requires the preparation of the *negotiating framework* that the DNSPs must comply with (clause 6.7A.2). It also stipulates the requirements of the *negotiating framework*.

This Appendix is intended to provide the information to address the Transitional Rules requirements.

1.3 Negotiable Components

For the purposes of the *2009 regulatory control period*, a Negotiable Component is a particular component :

(a) of a *direct control service* provided by Integral Energy; or

(b) which relates to the terms or conditions on which a *direct control service* or a component of the *direct control service* is provided by Integral,

which the AER has determined to be a negotiable component in a distribution determination pursuant to 6.7A(a) of the Rules but does not include *negotiated distribution services* or unregulated *distribution services*.

Integral Energy proposes that the following components of *direct control services* be classified as the Negotiable Components of *direct control services* with respect to the 2009 regulatory control period pursuant to clause 6.8.2(7) of the Transitional Rules:

(a) a *direct control service* that exceeds the network performance requirements which that *direct control service* is required to meet under any jurisdictional electricity legislation;

(b) a *direct control service* that, except to the extent that the network performance requirements which that *direct control service* is required to meet are prescribed under any jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as are set out in schedule 5.1a or 5.1;

(c) a *direct control service* that is a *connection service* provided to serve a Distribution Network User or group of Distribution Network Users, at a single distribution network connection point, other than connection services that are provided by one Network Service Provider to another Network Service Provider to connect their networks where neither of the Network Service Providers is a Market Network Service Provider; or

(d) the terms and conditions in respect of which any of the above are provided.

1.4 Proposed negotiating framework

Integral Energy proposes the following negotiating framework:

1. Application of negotiating framework

1.1 This negotiating framework applies to Integral Energy and each Service Applicant who has made an application in writing to Integral Energy for the provision of a Negotiable Component

1.2 Integral Energy and any Service Applicant who wishes to receive a Negotiable Component from Integral Energy must comply with the requirements of this negotiating framework.

1.3 The requirements set out in this negotiating framework are additional to any requirements or obligations contained in the Transitional Rules. In the event of any inconsistency between this negotiating framework and any requirements in the Transitional Rules, the requirements of the Transitional Rules will prevail.

1.4 Nothing in this negotiating framework or in the Transitional Rules will be taken as imposing an obligation on Integral Energy to provide any service to the Service Applicant.

2. Obligation to negotiate in good faith

2.1 Integral Energy and the Service Applicant must negotiate in good faith the terms and conditions of access for the provision by Integral Energy of the Negotiable Component sought by the Service Applicant.

3. Timeframe for commencing, progressing and finalising negotiations

3.1 Paragraph 3.4 sets out the timeframe for commencing, progressing and finalising negotiations in relation to applications for Negotiable Components under the Transitional Rules.

3.2 The timeframes set out in paragraph 3.4 may be suspended in accordance with paragraph 8.

3.3 Integral Energy and the Service Applicant must use reasonable endeavours to adhere to the time periods specified in paragraph 3.4 during the negotiation for the supply of the Negotiable Component.

3.4 The preliminary program finalised under C in Table 1 may be modified from time to time by agreement of the parties, where such agreement must not be unreasonably withheld. Any such amendment to the preliminary program will be taken to be a reasonable period of time for commencing, progressing and finalising negotiations with a Service Applicant for the provision of the Negotiable Component for the purposes of 6.7A.5(c)(5) of the Transitional Rules. The requirement in paragraph 3.3 applies to the last amended preliminary program.

Table 1

	Event	**Indicative timeframe**
A	Receipt of written application for a Negotiable Component	X
B	Parties meet to discuss a preliminary program with milestones for supply of the Negotiable Component that represent a reasonable period of time for commencing, progressing and finalising negotiations for the provision of the Negotiable Component	X + 20 business days
C	Parties finalise preliminary program, which may include, without limitation, milestones relating to: • the request and provision of commercial information; and • notification and consultation with NEMMCO	X + 30 business days

	Event	Indicative timeframe
	and / or any affected Distribution Network Users.	
D	Integral Energy provides Service Applicant with an offer for the Negotiable Component	X + 120 business days
E	Parties finalise negotiations	X + 160 business days

3.5 Subject to paragraphs 3.2 to 3.4, Integral Energy and the Service Applicant must, following a request for a Negotiable Component, use their reasonable endeavours to:

3.5.1 hold a meeting within 20 Business Days of receipt of the application, or such other period as agreed by the parties, in order to agree a timetable for the conduct of negotiations and to commence discussion regarding other relevant issues;

3.5.2 progress the negotiations for the provision of a Negotiable Component by Integral Energy such that the negotiations may be finalised in accordance with the timetable referred to in paragraph 3.5.1;

3.5.3 adhere to any timetable established for the negotiation and to progress the negotiation in an expeditious manner; and

3.5.4 finalise the negotiations for the provision of a Negotiable Component by Integral Energy within a time period agreed by the parties.

3.6 Notwithstanding paragraph 3.1, or any other provision of this negotiating framework, the timeframes set out in paragraphs 3.2 to 3.4:

3.6.1 do not commence until payment of the amount to Integral Energy pursuant to paragraph 10;

3.6.2 recommence if there is a material change in the Negotiated Distribution Service sought by the Service Applicant, unless Integral Energy agrees otherwise.

3.7 At the conclusion of the negotiations between Integral Energy and the Service Applicant, whether by way of agreed outcome or termination pursuant to clause 11 of this Negotiating Framework, Integral Energy must publish the results of the negotiations on its website.

4. Provision of initial commercial information by Service Applicant

4.1 Integral Energy must request the Service Applicant to provide it with the Commercial Information held by the Service Applicant that Integral reasonably requires to enable it to engage in effective negotiations with the Service Applicant in relation to the application and to enable Integral Energy to submit Commercial Information to the Service Applicant. Integral Energy must use its reasonable endeavours to make the request within the period of time agreed by the parties pursuant to clause 3.

4.2 The Service Applicant must provide Integral Energy with the Commercial Information held by it which Integral Energy reasonably requires to engage in effective negotiations with the Service Applicant in relation to the application. Subject to paragraphs 4.3 and 4.4, the Service Applicant must use its reasonable endeavours to provide Integral Energy with the Commercial Information requested by Integral Energy in accordance with paragraph 4.1 within 10 Business Days of that request, or within a time period as agreed by the parties.

4.3 Notwithstanding paragraph 4.1, the obligation under paragraph 4.1 is suspended as at the date of notification of a dispute if a dispute under this negotiating framework arises until conclusion of the dispute in accordance with paragraph 9.

Confidentiality requirements – Commercial Information

4.4 Commercial Information may be provided by the Service Applicant subject to the condition that Integral Energy must not disclose the Commercial Information to any other person unless the Service Applicant consents in writing to the disclosure. The Service Applicant may require Integral Energy to enter into a confidentiality agreement, on terms reasonably acceptable to both parties, with the Service Applicant in respect of any Commercial Information provided to Integral Energy.

4.5 A consent provided by the Service Applicant in accordance with paragraph 4.4 may be subject to the condition that the person to whom Integral Energy discloses the Commercial Information must enter into a separate confidentiality agreement with the Service Applicant.

5. Provision of additional Commercial Information by the Service Applicant

Obligation to provide additional Commercial Information

5.1 Integral Energy may give a notice to the Service Applicant requesting the Service Applicant to provide Integral Energy with any additional Commercial Information that is reasonably required by Integral Energy to enable it to engage in effective negotiations with the Service Applicant in relation to the provision of a Negotiable Component or to clarify any Commercial Information provided pursuant to paragraph 4.

5.2 The Service Applicant must use its reasonable endeavours to provide Integral Energy with the Commercial Information requested by Integral Energy in accordance with paragraph 5.1 within 10 Business Days of the date of the request under paragraph 5.1, or such other period as agreed by the parties.

5.3 The provision of additional Commercial Information by the Service Applicant pursuant to clause 5.2 is subject to the provisions in clauses 4.4 and 4.5 above.

6. Provision of Commercial Information by Integral Energy

Obligation to provide commercial information

6.1 Integral Energy must provide the Service Applicant with all Commercial Information held by Integral Energy that is reasonably required by a Service Applicant to enable it to engage in effective negotiations with Integral Energy for the provision of a Negotiable Component within a timeframe agreed by the parties, including the following information:

6.1.1 a description of the nature of the Negotiable Component including what Integral Energy would provide to the Service Applicant as part of that service;

6.1.2 the terms and conditions on which Integral Energy would provide the Negotiable Component to the Service Applicant;

6.1.3 the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the Negotiable Component to the Service Applicant which demonstrate to the Service Applicant that the charges for providing the Negotiable Component reflect those costs and/or the cost increment or decrement (as appropriate).

6.2 For the purpose of paragraph 6.1.3, Integral Energy must have appropriate arrangements for the assessment and review of the charges and the basis on which they are made.

Confidentiality requirements

6.3 Integral Energy may provide the Commercial Information in accordance with paragraph 6.1 subject to the condition that the Service Applicant must not disclose the Commercial Information to any other person unless Integral Energy consents in writing to the disclosure. Integral Energy may require the Service Applicant to enter into a confidentiality agreement with Integral Energy, on terms reasonably acceptable to both parties, in respect of Commercial Information provided to the Service Applicant.

6.4 A consent provided by a Service Applicant in accordance with paragraph 6.3 may be subject to the condition that the person to whom the Service Applicant discloses the Commercial Information must enter into a separate confidentiality agreement with Integral Energy.

7. Determination of impact on other Distribution Network Users and consultation with affected parties

7.1 Integral Energy must determine the potential impact on Distribution Network Users, other than the Service Applicant, of the provision of the Negotiable Component.

7.2 Integral Energy must notify and consult with any affected Distribution Network Users and ensure that the provision of the Negotiable Component does not result in non-compliance with obligations in relation to other Distribution Network Users under the Rules.

8. Suspension of timeframe for provision of Negotiable Component

8.1 The timeframes for negotiation of provision of a Negotiable Component as contained within this negotiating framework, or as otherwise agreed between the parties, are suspended if:

8.1.1 within 15 Business Days of Integral Energy providing the Commercial Information to the Service Applicant pursuant to paragraph 6.1, the Service Applicant does not formally accept that Commercial Information and the parties have agreed a date for the undertaking and conclusion of commercial negotiations;

8.1.2 a dispute in relation to the Negotiable Component has been notified to Integral Energy or the Service Applicant (as applicable) in accordance with Chapter 8 of the Rules, from the date of that notification until the date of withdrawal of the dispute or resolution of the dispute under Chapter 8 of the Rules (as applicable);

8.1.3 within 10 Business Days of Integral Energy requesting additional Commercial Information from the Service Applicant pursuant to paragraph 5, the Service Applicant has not supplied that Commercial Information;

8.1.4 without limiting paragraphs 8.1.1 to 8.1.3, if either of the parties does not promptly meet any of its obligations as required by this negotiating framework or as otherwise agreed by the parties;

8.1.5 Integral Energy has been required to notify and consult with any affected Distribution Network Users under paragraph 7.2, or NEMMCO at any time regarding the provision of the Negotiable Component. In those circumstances, the time frame for the negotiations will be suspended from the date of notification to the affected Distribution Network Users or NEMMCO until:

(a) the end of the time limit specified by Integral Energy for any affected Distribution Network Users or NEMMCO; or

(b) the receipt of information from the affected Distribution Network Users or NEMMCO regarding the provision of the Negotiable Component,

whichever is the later.

9. Dispute resolution

9.1 All disputes between the parties as to the terms and conditions of access for the provision of a Negotiable Component are to be dealt with in accordance with the NEL and Chapter 8 of the Rules.

10. Payment of Integral Energy's Costs

10.1 Prior to commencing negotiations, the Service Applicant must pay an application fee to Integral Energy. The fee must be no more than Integral Energy's reasonable estimate of its costs in dealing with the application. The payment is to be made in accordance with clause 6.7A.5(c)(5) of the Rules.

10.2 The application fee lodged pursuant to paragraph 10.1 will be deducted from the reasonable direct Costs incurred in processing the Service Applicant's application to Integral Energy for the provision of a Negotiable Component.

10.3 From time to time, Integral Energy may give the Relevant Service Applicant a notice setting out the reasonable direct Costs incurred by Integral Energy and the off-set of any amount applicable under paragraph 10.1.

10.4 If the aggregate of the reasonable direct Costs exceed the amount paid by the Service Applicant pursuant to paragraph 10.1, the Service Applicant must, within 20 Business Days of the receipt of a notice in accordance with paragraph 10.3, pay Integral Energy the amount stated in the notice. If the aggregate of its actual reasonable direct Costs is less than the amount paid by the Service Applicant pursuant to paragraph 10.1, Integral Energy must promptly notify the Service Applicant and must within 20 Business Days of the date of that notice refund to the Service Applicant the amount by which the application fee paid by the Service Applicant under paragraph 10.1 exceeds Integral's actual aggregate reasonable direct Costs.

10.5 Integral Energy may require the Service Applicant to enter into a binding agreement addressing conditions, guarantees and other matters in relation to the payment of on-going Costs.

11. Termination of negotiations

11.1 The Service Applicant may elect not to continue with its application for a Negotiable Component and may terminate the negotiations by giving Integral Energy written notice of its decision to do so.

11.2 Integral Energy may terminate a negotiation under this framework by giving the Service Applicant written notice of its decision to do so where:

11.2.1 Integral Energy believes on reasonable grounds that the Service Applicant is not conducting the negotiation under this negotiating framework in good faith;

11.2.2 Integral Energy reasonably believes that the Service Applicant will not acquire any Negotiable Component;

11.2.3 An act of Solvency Default occurs in relation to the Service Applicant.

12. Giving notices

12.1 A notice, consent, information, application or request that must or may be given or made to a party under this document is only given or made if it is in writing and delivered or posted to that party at its address set out below.

If a party gives the other party 5 Business Days' notice of a change of its address, a notice, consent, information, application or request is only given or made by that other party if it is delivered or posted to the latest address.

<u>Integral Energy</u>

Name: Integral Energy Australia

Address: 51 Huntingwood Drive, Huntingwood NSW 2148 or

PO Box 6366, Blacktown NSW 2148

Service Applicant

Name: Service Applicant

Address: The nominated address of the Service Applicant provided in writing to Integral Energy as part of the application

Time notice is given

12.2 A notice, consent, information, application or request is to be treated as given or made at the following time:

12.2.1 if it is delivered, when it is left at the relevant address;

12.2.2 if it is sent by post, 2 Business Days after it is posted;

12.2.3 if sent by facsimile transmission, on the day the transmission is sent (but only if the sender has a confirmation report specifying a facsimile number of the recipient, the number of pages sent and the date of transmission); or

12.2.4 if sent by email once acknowledged as received by the addressee.

12.3 If a notice, consent, information, application or request is delivered after the normal business hours of the party to whom it is sent, it is to be treated as having been given or made at the beginning of the next Business Day.

13. Definitions and interpretation

Definitions

13.1 In this document the following definitions apply:

Business Day means a day on which all banks are open for business generally in Sydney, New South Wales.

Commercial Information includes, but is not limited to, the following classes of information:

- details of corporate structure;
- financial details relevant to creditworthiness and commercial risk;
- ownership of assets;
- technical information relevant to the application for a Negotiable Component;

- financial information relevant to the application for a Negotiable Component;

- details of an application's compliance with any law, standard, NER or guideline,

but does not include:

- confidential information provided by another person to either:

  - the Service Applicant; or

  - Integral Energy;

- information that the Service Applicant is prohibited, by law, from disclosing to Integral Energy; or

- information that Integral Energy is prohibited, by law, from disclosing to the Service Applicant.

Costs means any costs or expenses incurred by Integral Energy in complying with this negotiating framework or otherwise advancing the Service Applicant's request for the provision of a Negotiable Component.

Integral Energy means Integral Energy Australia, ABN 59 253 130 878.

Negotiable Component has the meaning given in clause 1.3.

Solvency Default means the occurrence of any of the following events in relation to the Service Applicant:

(a) An originating process or application for the winding up of the Service Applicant (other than a frivolous or vexatious application) is filed in a court or a special resolution is passed to wind up the Service Applicant, and is not dismissed before the expiration of 60 days from service on the Service Applicant;

(b) A receiver, receiver and manager or administrator is appointed in respect of all or any part of the assets of the Service Applicant, or a provisional liquidator is appointed to the Service Applicant;

(c) A mortgagee, chargee or other holder of security, by itself or by or through an agent, enters into possession of all or any part of the assets of the Service Applicant;

(d) A mortgage, charge or other security is enforced by its holder or becomes enforceable or can become enforceable with the giving of notice, lapse of time or fulfilment of a condition;

(e) The Service Applicant stops payment of, or admits in writing its inability to pay, its debts as they fall due;

(f) The Service Applicant applies for, consents to, or acquiesces in the appointment of a trustee or receiver of the Service Applicant or any of its property;

(g) A court appoints a liquidator, provisional liquidator, receiver or trustee, whether permanent or temporary, of all or any part of the Service Applicant's property;

(h) The Service Applicant takes any step to obtain protection or is granted protection from its creditors under any applicable legislation or a meeting is convened or a resolution is passed to appoint an administrator or controller (as defined in the Corporations Act 2001), in respect of the Service Applicant;

(i) A controller (as defined in the Corporations Act 2001) is appointed in respect of any part of the property of the Service Applicant;

(j) Except to reconstruct or amalgamate while solvent, the Service Applicant enters into or resolves to enter into a scheme of arrangement, compromise or reconstruction proposed with its creditors (or any class of them) or with its members (or any class of them) or proposes re-organisation, re-arrangement moratorium or other administration of the Service Applicant's affairs;

(k) The Service Applicant is the subject of an event described in section 459C(2)(b) of the Corporations Act 2001; or

(l) Anything analogous or having a substantially similar effect to any of the events specified above happens in relation to the Service Applicant.

Interpretation

13.2 In this document, unless the context otherwise requires:

13.2.1 terms defined in the Transitional Rules have the same meaning in this negotiating framework;

13.2.2 a reference to any law or legislation or legislative provision includes any statutory modification, amendment or re-enactment, and any subordinate legislation or regulations issued under that legislation or legislative provision;

13.2.3 a reference to any agreement or document is to that agreement or document as amended, novated, supplemented or replaced from time to time;

13.2.4 a reference to a paragraph, part, schedule or attachment is a reference to a paragraph, part, schedule or attachment of or to this document unless otherwise stated;

13.2.5 an expression importing a natural person includes any company, trust, partnership, joint venture, association, corporation, body corporate or governmental agency; and

13.2.6 a covenant or agreement on the part of two or more persons binds them jointly and severally.

Appendix G: Miscellaneous services, monopoly services and emergency recoverable works

G.1 Miscellaneous services

G.1.1 Supply of Conveyancing Information desk inquiry

The provision of information regarding the availability of supply, presence of DNSP’s equipment, power lines and like information for property conveyancing purposes undertaken without any physical inspection of a site, other than the provision of information or the answering of inquiries relating to any matter under freedom of information legislation.

G.1.2 Supply of conveyancing information field visit

The provision of information regarding the availability of supply, presence of DNSP's equipment, power lines and like information for property conveyancing purposes undertaken by a physical inspection of a site, other than the provision of information or the answering of inquiries relating to any matter under freedom of information legislation.

G.1.3 Meter test

The testing of a meter in accordance with clause 6.4 of the *Market Operations Rule (NSW Rules for Electricity Metering) No. 3 of 2001* (except for metering installation types 1 to 4, the testing of which is an unregulated distribution service).

G.1.4 Special meter reading

This service:

1. has the same meaning as the meaning given to the expression “special meter read” in the *Market Operations Rule (NSW Rules for Electricity Metering) No. 3 of 2001* (but excludes any special meter reading of metering installation types 1 to 4, which is an unregulated distribution service);

and applies in each of the following circumstances:

2. where a customer or a retail supplier requests that the DNSP undertake a special meter read, (but does not apply where the special meter read was requested solely to verify the accuracy of a scheduled meter read and the special meter read reveals that the scheduled meter read was inaccurate or in error) or
3. where the DNSP attends at a customer’s premises for the sole purpose of discharging the DNSP’s obligation to read the customer’s meter within the period specified by law (but not where the DNSP merely chooses to read the customer’s meter without being under a legal obligation to do so) and on attending the customer’s premises the DNSP is unable (through no act or omission of the DNSP), to gain access to the meter or
4. where the DNSP and the customer agree on an appointed time at which the DNSP may attend the customer’s premises to enable the DNSP to discharge the DNSP’s legal obligation referred to in section G.1.4(3) and when the DNSP attended at the

customer's premises at the appointed time the DNSP (through no act or omission of the DNSP), was unable to gain access to the customer's meter.

G.1.5 Disconnection visit (acceptable payment received)

A site visit to a customer's premises on an occasion for the purpose of disconnecting the customer's supply for breach by the customer of a customer supply contract or a customer connection contract, where the disconnection does not occur on that occasion.

G.1.6 Disconnection at meter box

A site visit to a customer's premises to:

1. disconnect the supply of electricity to a customer via either the main switch or service fuse removal for breach by the customer of a customer supply contract or a customer connection contract, or where a retail supplier has requested that the supply to the customer be disconnected and
2. reconnect the supply following the disconnection in section G.1.6(1).

G.1.7 Disconnection at pole top/pillar box

A site visit to a customer's premises:

1. to disconnect the supply of electricity to a customer at the pole top or pillar box for breach by the customer of a customer supply contract or a customer connection contract, or where a retailer supplier has requested that the supply to a customer be disconnected, where the customer has denied access to the meter or had prior to the visit, reconnected supply without authorisation by the DNSP following a previous disconnection and
2. to reconnect the supply, following the disconnection in section G.1.7(1).

G.1.8 Rectification of illegal connection

Work undertaken by a DNSP to the property of the DNSP or to the property of another person in order to:

(1) rectify damage or

(2) prevent injury to persons or property,

resulting from conduct that constitutes an offence under part 6, division 1 of the *Electricity Supply Act 1995* (NSW).

G.1.9 Off–peak conversion

The alteration of the off-peak meter at a customer's premises for the purpose of changing the hours of the meter's operation.

G.1.10 Reconnection outside normal business hours

1. The provision of the reconnection component of the service described in sections G.1.6(2) and G.1.7(2) outside the hours of 7.30 am and 4.00 pm on a working day, at the request of a customer or

2. The connection of electricity to a new customer outside the hours of 7.30 am and 4.00 pm on a working day at the request of the customer.

G.2 Monopoly services

G.2.1 Design information

The provision of information by a DNSP to enable an ASP accredited for level 3 work to prepare a design drawing and to submit it for certification.

This may include without limitation:

1. deriving the estimated loading on the system, technically known as the ADMD (after diversity maximum demand). This estimate depends on such factors as the number of customers served and specific features of the customers' demand
2. copying drawings that show existing low and high voltage circuity (geographically and schematically) and adjacent project drawings
3. specifying the preferred sizes for overhead wires (conductors) or underground wires (cables)
4. specifying switchgear configuration type, number of pillars, lights etc
5. determining the special requirements of the DNSP's planning departments necessary to make electrical supply available to a development and cater for future projects
6. any necessary liaison with designers associated with assistance in sourcing design information and developing designs
7. nominating network connection points.

G.2.2 Design certification

A certification by a DNSP that a design (if implemented) will not compromise the safety or operation of the DNSP's distribution system.

This may include, without limitation:

1. certifying that the design information/project definition have been incorporated in the design
2. certifying that easement requirements and earthing details are shown
3. considering design issues, including checking for over-design and mechanisms to permit work on high voltage systems without disruption to customers' supply (adequate LV parallels)
4. certifying that funding details for components in the scope of works are correct
5. certifying that there are no obvious errors that depart from the DNSP's design standards and specifications
6. certifying that shared assets are not over-utilised to minimise developer's connection costs and that all appropriate assets have been included in the design

7. auditing design calculations such as voltage drop calculations, conductor clearance (stringing) calculations etc
8. certifying that a bill of materials has been submitted; or
9. certifying that an environmental assessment has been submitted by an accredited person and appropriately checked.

G.2.3 Design rechecking

The rechecking of a design submitted under section 1.2.2, except where the modifications to a design are of a trivial or minor nature.

G.2.4 Inspection of service work (level 1 work)

The inspection by a DNSP of work undertaken by an ASP accredited to perform level 1 work, for the purpose of ensuring the quality of assets to be handed over to the DNSP.

G.2.5 Inspection of service work (level 2 work)

The inspection by a DNSP of work performed by an ASP accredited to perform level 2 work, complying with the condition below.

Condition

The minimum number of inspections required must correspond to the grade of the DNSP in table G.1 below:

Table G.1: Inspection rate

Grade	Number of inspections
A	1 inspection per 25 jobs
B	1 inspection per 5 jobs
C	Each job to be inspected

G.2.6 Re-inspection of level 1 or level 2 work

The re-inspection by a DNSP of work (other than customer installation work) undertaken by an ASP accredited to perform level 1 or level 2 work, for the reason that on first inspection the work was found not to be satisfactory.

G.2.7 Re-inspection of work of a service provider

The re-inspection by a DNSP of customer installation work undertaken by a service provider for the reason that on first inspection the work was found not to be satisfactory.

G.2.8 Access permit

The provision of a permit by a DNSP to a person authorised by law to work on or near a distribution system.

This may include without limitation:

1. researching and documenting the request for access
2. documenting the actual switching process
3. programming the work
4. control room activities
5. fitting and removing of operational earths
6. the actual switching together with any operator's transport costs
7. identification of any customers who will be interrupted
8. low voltage switching and paralleling of substations that permits high voltage work without disrupting supply to other customers.

G.2.9 Substation commissioning

The commissioning by a DNSP of a new substation, (whether it is a single pole, padmount/kiosk or indoor/chamber) and includes:

1. all necessary pre-commissioning checks and tests prior to energising the substation via the high voltage switchgear and closing the low voltage circuit breaker, links or fuses and
2. the setting or resetting of protection equipment.

G.2.10 Administration

Work of an administrative nature (not including work of an administrative nature described in section G.2.11), involving the processing of level 1 and/or level 3 work where the customer is lawfully required to pay for the level 1 and /or level 3 work.

This may include without limitation:

1. checking supply availability
2. processing applications
3. correspondence from application to completion
4. record-keeping
5. requesting and receiving fees (initially, then prior to design and after certification)
6. receiving design drawings (registering and copying)
7. raising an order for high voltage (HV) work
8. calculating HV reimbursements
9. calculating the cost of a project and warranty/maintenance bond
10. organising refunds to developers for HV work
11. liaising with developers via phone and facsimile
12. updating geographic information systems (GIS) and mapping.

G.2.11 Notice of arrangement

Work of an administrative nature performed by a DNSP where a local council requires evidence in writing from a DNSP that all necessary arrangements have been made to supply electricity to a development.

This may include without limitation:

1. receiving and checking linen plans and 88B Instruments
2. copying linen plans
3. checking and recording easement details
4. preparing files for conveyancing officers
5. liaising with developers if errors or changes are required
6. checking and receiving duct declarations and any amended linen plans and 88B instruments approved by a conveyancing officer
7. preparing notifications of arrangement.

G.2.12 Access

The provision of access to switchrooms, substations and the like to an ASP who is accompanied by a member of staff of a DNSP, but does not include the circumstance where an ASP is provided with keys for the purpose of securing access and is not accompanied by a member of staff of a DNSP.

G.2.13 Authorisation

The annual authorisation by a DNSP of individual employees or sub-contractors of an ASP to carry out work on or near a DNSP's distribution system.

This may include without limitation:

1. familiarisation and training in the DNSP's safety rules and access permit requirements
2. induction in the unique aspects of the network
3. verification that the applicant has undertaken the necessary safety training (resuscitation etc) within the last 12 months
4. conducting interviews/examinations for access permit recipients
5. issuing authorisation cards.

G.2.14 Site establishment

The issue of a meter by a DNSP and its co-ordination with NEMMCO for the purpose of establishing a NMI in MSATS for new premises or for any existing premises for which NEMMCO requires a new NMI and for checking and updating network load data.

G.3 Emergency recoverable works

Emergency work undertaken by a DNSP to repair damage to the distribution system of that DNSP where the damage is the consequence of the act or omission of a person, for which that person is liable to another (which may include the DNSP) for that damage.

For example, emergency work undertaken by the DNSP to repair damage to the DNSP's distribution system resulting from a motor vehicle collision where the driver was negligent.

G.4 Definitions and interpretation

G.4.1 Definitions

(1) In this appendix:

ASP means an accredited service provider and is a person who has been accredited under Part 10 Electricity Supply (General) Regulation 2001 (NSW)

MSATS means the market settlement and transfer system operated by NEMMCO

NMI means a national metering identifier

service provider means a person who may lawfully undertake customer installation work

(2) In this appendix the following expressions have the meaning given to them in the *Electricity Supply Act 1995* (NSW):

electricity supply contract

electricity connection contract

retail supplier.

(3) References to sections are references to sections in this appendix.

G.4.2 Interpretation of grade or level of accreditation

1. In this appendix, the reference to a grade or level, means the grade or level for which an ASP is accredited, applying the classification system in table 2 below.
2. If the classification system in table G.2 is amended during this decision, the reference in this appendix to a grade or level will be taken to be a reference to the grade or level in the amended classification system that most closely approximates the grade or level in table G.2.

Table G.2 Classification

Accreditation	Type of work	Category
Level 1	Construction of transmission and distribution works, including high and low voltage, overhead and underground reticulation and substations.	Underground (UG) Overhead (OH)
Level 2	Service Work: Construction and/or installation of the service line interface between the distribution system and consumer terminals, including metering services	Disconnection and reconnection Underground (UG) service lines Overhead (OH) service lines Metering and energising new installations Installing contestable metering – under review
Level 3	Design of transmission and distribution works	Underground (UG) Overhead (OH)

Appendix H: Fees and charges - miscellaneous services, monopoly services and emergency recoverable works

H.1 Introduction

The miscellaneous services, monopoly services and emergency recoverable works in this appendix (having the abbreviated descriptions given to them in sections H.3, H.4 and H.5 respectively) have the full meaning given to them in appendix G of this draft decision.

H.2 Levying charges for miscellaneous services, monopoly services and emergency recoverable works

(a) The charge that may be levied by a DNSP for the provision of a miscellaneous service described in section H.3 or emergency recoverable works specified in section H.5, must not be more than (but may be less than) the charge specified or calculated for the miscellaneous service in section H.3 or the emergency recoverable work in section H.5 respectively.

(b) Unless otherwise specified, the charge that is to be levied by a DNSP for the provision of a monopoly service described in section H.4, must not be more than or less than the charge specified or calculated for that monopoly service in that section.

(c) The charges for miscellaneous services, monopoly services and emergency recoverable works in this appendix are to be levied in accordance with the conditions (if any) specified in appendix G of this decision applying to each service and in accordance with the conditions accompanying the respective sections in this appendix.

H.3 Miscellaneous services

H.3.1 Charges for miscellaneous services

The charges in table H.1 below apply:

Table H.1 Charges for miscellaneous services

Miscellaneous service	$
Special meter reading	$42
Meter test	$70
Supply of conveyancing information – desk inquiry	$35
Supply of conveyancing information – field visit	$70
Off-peak conversion	$57
Disconnection visit (acceptable payment received)	$42
Disconnection at meter box	$84
Disconnection at pole top/pillar box	$141
Rectification of illegal connection	$211
Reconnection outside business hours	$90

H.3.2 Conditions relating to charges for miscellaneous services

(a) Disconnection at meter box and pole/top pillar box

For the avoidance of doubt, if, following a request from a customer, the reconnection component of the services described in section H.3.1 as “disconnection at meter box” and “disconnection at pole top/pillar box” are provided outside the hours of 7.30 am and 4.00 pm on a working day, the charge that the DNSP may levy for the provision of each of those services will be the charge for each service in section H.3.1 plus the charge for the service described as “reconnection outside normal business hours”, if applicable.

(b) Meter test

If the service described as “meter test” is undertaken on premises serviced by more than one meter the following applies:

(1) if the meter test reveals that all of the meters are operating satisfactorily, a DNSP may only levy one charge for the provision of the service as if the meter test were undertaken on a single meter

(2) if the meter test reveals that one or more of the meters are not operating satisfactorily, the DNSP may not levy any charge for the provision of the service.

(c) Special meter reading

A charge may not be levied for the service described as “special meter reading” in either of the following circumstances:

(1) where the customer is moving or is about to move premises or

(2) where the service reveals that a scheduled meter reading was inaccurate.

(d) Off-peak conversion

A charge for the service described as "off-peak conversion" may only be levied for each occasion that the service is provided in excess of once in any 12 month period.

H.4 Monopoly services

H.4.1 Charges for monopoly services

Table H.4 Charges for monopoly services

Monopoly service	Underground urban residential subdivision (vacant lots)	Rural overhead subdivisions and rural extensions	Underground commercial and industrial or rural subdivisions (vacant lots – no development)	Commercial and industrial developments	Asset relocation or street lighting
Design information	Up to 5 lots $152 6 to 10 lots $228 11 to 40 lots $380 Over 40 lots $456	R2 per hour	R2 per hour	R2 per hour	R2 or R3 per hour (see para 1.4.2)
Design certification	Up to 5 lots $76 6 to 10 lots $152 11 to 40 lots $228 Over 40 lots $304	1 to 5 poles $76 6 to 10 poles $152 11 or more poles $228	Up to 10 lots $152 11 to 40 lots $228 Over 40 lots $456	R3 per hour	R2 or R3 per hour (see para 1.4.2)
Design rechecking	R2 per hour	R2 per hour	R2 per hour	R3 per hour	R2 or R3 per hour (see para 1.4.2)
Inspection of service work (level 1 work)	Grade / A per lot / B per lot / C per lot First 10 lots / $39 / $92 / $190 Next 40 lots / $23 / $53 / $114 Remainder / $7 / $30 / $53	Grade / A per pole / B per pole / C per pole 1 - 5 poles / $46 / $92 / $168 6 - 10 poles / $39 / $76 / $152 11+ poles / $30 / $53 / $114 (See para 1.4.2)	Grade / A per lot / B per lot / C per lot First 10 lots / $39 / $92 / $190 Next 40 lots / $39 / $92 / $190 Remainder / $39 / $92 / $190	R2 or R3 per hour	R2 or R3 per hour (see para 1.4.2)
Access permit	Residential subdivisions: $25 per lot combined fee	$1127 maximum per access permit	$1127 maximum per access permit	$1127 maximum per access permit	$1127 maximum per access permit
Substation commissioning		$845 per substation (see para 1.4.2)	$845 per substation (see para 1.4.2)	$845 per substation (see para 1.4.2)	$845 per substation (see para 1.4.2)
Administration	Up to 5 lots $184 6 to 10 lots $246 11 to 40 lots $307 Over 40 lots $369	Up to 5 poles $184 6 to 10 poles $246 11 or more poles $369	R1 per hour (max 6 hours)	R1 per hour (max 6 hours)	R1 per hour
Notice of arrangement	$184				
Re-inspection (level 1 and 2 work)	R2 per hour (maximum 1 hour per level 2 reinspection)				
Re-inspection (service provider)	$76 For the purpose of para 1.2(b), a DNSP may charge a fee that is less than this fee, but not a fee that is more than this fee.				
Access	R1 per hour				
Authorisation	$152				
Inspection of service work (level 2 work)	All service connections: A Grade: $19 per NOSW (NOSW = Notification of service work)	B Grade: $31 per NOSW	C Grade: $92 per NOSW		
Site establishment	$133				

H.4.2 Conditions relating to charges for monopoly services

(a) Inspection

For the service described as "inspection":

1. in the case of "commercial and industrial developments" and "asset relocation or street lighting", the level of inspection is to be determined by the DNSP prior to performing the service
2. the grade specified is the grade of the ASP, accredited for that grade
3. in the case of "rural overhead subdivisions and rural extensions", the charge applies to inspections (other than substation poles) and represents the total charge for three separate visits. For substation poles the charge for ASP grade A is $266; for grade B is $531 and for grade C is $670.

(b) Substation commissioning

For the service described as "substation commissioning" (other than in the case of "underground urban residential subdivision vacant lots") the charge specified is to be levied only where it is a single transformer/RMI unit. In all other cases the service is to be charged at the R3 labour rate.

(c) Lots

In table H.4, where the monopoly service relates to a service connection required for multiple dwelling subdivisions, the per lot fee in that table should be applied per service connection.

(d) Design information/design certification/ design rechecking

For the services described as "design information", "design certification" and "design rechecking", the labour rate (R2 or R3) is to be applied based on the DNSP's assessment of the level of skill required to perform the service.

(e) Travel time

In addition to the charge specified or calculated under section H.4.1, a DNSP must charge for that amount of travel time (permitted for that DNSP in table H.5 below) associated with the inspection of level 1 work at the R2 labour rate.

Table H.5: Travel time

DNSP	Amount of travel time permitted
EnergyAustralia	30 minutes
Integral Energy	30 minutes
Country Energy	60 minutes

(f) Overtime

If a monopoly service is provided outside the hours of 7.30 am and 4.00 pm on a working day at the request of an ASP (other than where the DNSP requires that the work be performed outside those hours) the charge that the DNSP may impose for the provision of that service will be an amount up to 175 per cent of the charge for that service in section H.4.1.

(g) Labour rates

1. In section H.4.1 the references to R1, R2 and R3 denote the class of labour which performs the service at the hourly rate corresponding to the class in table 6 below.
2. For the purpose of the labour class R2 in the table, the DNSP will determine whether the service is to be provided by an inspector or an engineer at that class, depending on the nature and complexity of the service.

Table H.6: Labour rates

Labour class	Hourly rate
Admin R1	$61
Design R2a	$76
Inspector R2b	$76
Engineer R3	$92

H.5 Emergency recoverable works

H.5.1 Charges for emergency recoverable works

(a) The charge that a DNSP may levy for emergency recoverable works must not exceed the sum of the following:

(1) 110 per cent of the costs (other than labour costs) actually incurred in providing the emergency recoverable works and

(2) the cost of labour actually used to undertake the emergency recoverable works determined by applying 150 per cent of the R2 labour rate for that labour.

(b) For the avoidance of doubt, in the application of section H.5.1(a)(2), where a DNSP retains labour for a specified period for the purpose of that labour undertaking emergency recoverable works, the DNSP may only charge for so much of that specified period during which the labour actually undertakes the emergency recoverable works. For example, if a DNSP retains labour for a minimum specified period of four hours and the time required to actually undertake the emergency recoverable works is only one hour, the DNSP may only charge for the one hour and not the four hours.

H.5.2 Conditions for emergency recoverable works

The charges for emergency recoverable works in section H.5.1 apply irrespective of whether the works are provided on a working day or the time of day at which they are provided.

H.6 Definitions and interpretation

In this appendix, unless the context requires otherwise:

(a) expressions used in this appendix that are defined in appendix G of this draft decision, have the meaning given to them in that appendix G

(b) interpretation provisions in appendix G of this draft decision apply to this appendix

(c) references to sections are references to sections of this appendix.

Appendix I: Transmission overs and unders account

To demonstrate compliance with clause 6.18.7 of the transitional chapter 6 rules and the distribution determination for the next regulatory control period, the AER requires the NSW DNSPs to maintain a Transmission Overs and Unders account. The NSW DNSPs must provide information on this account to the AER as part of the annual pricing proposal under clause 6.18.2(b)(7).

As part of a pricing proposal for each regulatory year of the next regulatory control period, each NSW DNSP must provide the amounts for the following entries in its Transmission Overs and Unders account for the most recently completed regulatory year and forecasts for the next regulatory year:

1. opening balance for each year
2. interest accrued on the opening balance for each year, calculated at the rate of the post tax nominal rate of return as approved by the AER in the distribution determination
3. addition for the amount representing the revenue recovered from TUOS charges applied in respect of that year, less the amounts of all transmission related payments made by the DNSP in respect of that year
4. an adjustment to the net amount in item 3 by 6 months of interest, accrued at the approved nominal rate of return
5. summation of the above amounts to derive the closing balance for each year.

Note that estimates of values for the current regulatory year are not required or relevant to these calculations.

The NSW DNSPs must provide details of their calculations, in the format set out in table I.1.

For the avoidance of doubt, amounts may be either positive or negative and when added to each other, subtracted from each other or multiplied by another number may also yield, as the case maybe, positive amounts or negative amounts.

For amounts and information relating to 2007–08 and 2008–09, the NSW DNSPs will calculate and present these to the AER in accordance with Annexure 7 of IPART's *NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination*.

In proposing variations to the amount and structure of TUOS charges, the NSW DNSPs are to achieve a zero expected balance on their Transmission Unders and Overs account by the end of the next regulatory year.

Table I.1: Example calculation of transmission unders and overs account ($m)

	Year 1 (actual)	Yesr 3 (forecast)
Revenue from TUOS charges	100.00	103.45
Transmission related payments		
Transmission charges paid to TNSPs	90.00	91.00
Avoided TUOS payments approved by the AER	10.00	5.00
Inter-distributor payments to DNSPs	5.00	2.00
Total transmission related payments	105.00	98.00
Over (under) recovery	(5.00)	5.45
Unders and Overs account		
Annual rate of interest (applicable to balances)	9.00%	9.00%
Semi annual rate of interest (applicable to recoveries)	4.40%	4.40%
Opening balance of account	0.00	(5.22)
Interest on opening balance	0.00	(0.47)
Over (under) recovery for financial year	(5.00)	5.45
Interest on over/ under recovery	(0.22)	0.24
Closing balance of account	(5.22)	0.00

Appendix J: Changes to tariff structures and the weighted average price cap and side constraint formula

The weighted average price cap and side constraint are calculated using historical audited quantities of consumption. When revisions to tariff classes/components occur historical quantities for the new tariff classes/components will not be available for two years. This will occur in the following circumstances:

- the introduction of new tariffs
- the introduction of new tariff components for existing tariffs (for example, introducing a step rate for the usage component of the domestic tariff)
- changing the structure of existing tariffs or tariff components (this is essentially introducing a new tariff component, for example, changing the threshold on an inclining block tariff or the time bands associated with time of use tariffs)
- when customers move between existing tariffs (from origin tariffs to new tariffs).

This appendix sets out the adjustment process for incorporating such changes to tariff structures in the weighted average price cap formula when setting prices for Year (*t*), and for calculating the side constraint for affected tariffs. It provides for estimates for the historical quantity weights q_{ik}^{t-1}, and a substitute value for p_{ik}^{t} to be used when calculating compliance with the weighted average price cap, and for calculating the side constraint.

J.1 Value of q_{ik}^{t-1} when new tariffs or new tariff components are introduced

When a new tariff or a new tariff component is introduced,[929] there are no historical quantities available. In order to incorporate these tariffs in the weighted average price cap and calculate a side constraint, the AER requires reasonable estimates to be submitted by the DNSP, based on the quantities that would have been sold, if the new tariff (or new component) had been introduced in Year (*t*-1). The AER has adopted the following process, which was developed by IPART, in order for the DNSP to arrive at these estimates.

First, the DNSP must nominate the origin network tariff/s and/or network tariff component/s, which represents the tariff/s and/or component/s that the customer/s who will be moved to the new network tariff/s and/or network tariff component/s, are currently on, or currently being charged at. The DNSP must provide reasonable estimates for q_{ik}^{t-1} for all applicable units of measure (kWh, kW) for both, the new

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[929] This includes when an existing tariff component has undergone a structural change such that the new structure is essentially a new tariff component eg. changing the threshold value for a step rate, or time bands on a time of use tariff.

network tariff/s and/or network tariff component/s and the origin network tariff/s and/or the component/s.

Second, the DNSP must make the following assumptions when calculating the reasonable estimates:

1. The only customers that would have moved to the new network tariff and/or network tariff component in Year (t-1) moved as a result of the direction of the DNSP due to a change in tariff structures (as permitted under the customer's standard network connection contract).[930] This means that no new customer/s are included in the estimate,[931] nor customer/s that request to change tariff/s either voluntarily, or do so through the actions of the retailer.
2. Customer/s have the same consumption and load profile on the new network tariff and/or network tariff component as they did on the origin network tariff and/or network tariff component. This implies that the sum of the reasonable estimates for Year (t-1) for each unit of measure on the new network tariff and/or the network tariff component plus the reasonable estimates for Year (t-1) for each unit of measure on the origin network tariff and/or the network tariff component, equals the actual audited quantities that occurred for the origin network tariff and/or network tariff component in Year (t-1).

In the year after a new network tariff and/or tariff component has been introduced, there is still not a full year of actual historical data available to be used for q_{ik}^{t-1}, hence the DNSP will be required to submit reasonable estimates for both the new network tariff and/or the network tariff component and the corresponding origin network tariff and/or network tariff component. The DNSP may base the reasonable estimates on the actual quantities that have occurred to date on the new network tariff and/or the network tariff component and origin network tariff and/or network tariff component. The DNSP must demonstrate how it has arrived at the estimates.

J.2 Value of p_i^t when new tariffs or new tariff components are introduced

The p_{ik}^t of the corresponding origin network tariff and/or network tariff component/s will be used as the p_{ik}^t for the new network tariff and/or network tariff component/s (or the d_k^t in the side constraint formula). A corresponding origin network tariff component may be any component that is measured in the same units of measure as the new network tariff component/s. If there is no corresponding network tariff component/s with the same units of measure, p_{ik}^t will be set to zero.

[930] Each customer has a standard network connection contract with its DNSP and a separate contract with its respective retailer who manages the relationship with the DNSP on the customer's behalf.
[931] New customers have been allowed for in the growth assumption used when setting the X factor.

Table J.1: Example – introducing a step rate or inclining block tariff component

Tariff reform		p_{ik}^{t-1}	p_{ik}^{t}	q_{ik}^{t-1}
Existing tariff – standard domestic				
Fixed charge	$ pa per customer	$30	n/a	25 000 customers
Variable rate (all consumption)	c/kWh	0.04	n/a	200 000 MWh
Proposed tariff with new component				
Fixed charge	$ pa per customer	$30	$25	25 000 customers
Variable rate 1 (consumption up to 5000kWh per customer)	c/kWh	0.04 (above)	0.02	150 000 MWh
Variable rate 2 (consumption over 5000kWh per customer)	c/KWh	0.04 (above)	0.05	(200 000 –150 000) = 50 000 MWh

n/a: not applicable

J.3 Value of q_{ik}^{t-1} when customers are transferred by the DNSP to an alternative tariff

If the DNSP proposes to move a number of customers across to an alternative existing network tariff,[932] the rate at which revenue will accrue is different to what was used to calculate the X factor and will be different to what will be calculated under the weighted average price cap formula. In addition, the side constraint calculation will not reflect the actual increase to the customers being transferred. In these circumstances, the AER will require the DNSP to submit reasonable estimates for q_{ik}^{t-1} for each orgin network tariff that the customer is currently on, and the new network tariff that the DNSP will move the customers to, taking the transfer into account.

For compliance purposes, the assumptions the DNSP must make when calculating the reasonable estimates are:

1. The customer movement occurred in Year (t-1).
2. The customers only moved as a result of a direction of the DNSP due to a change in tariff structures (as permitted under the standard network connection

[932] The AER does not regulate the re-assignment or transfer of customers to alternative tariffs. The DNSP may decide to transfer customers if a customers' consumption or load profile has changed and the DNSP decides it is no longer appropriate for them to remain on the same tariff. Alternatively the DNSP may change the structure of an existing tariff to suit the majority of customers.

contract).[933] The estimates are not to include customers that may move at their discretion or due to the retailer discretion (voluntary movement).

3. Customers have the same consumption and load profile under either tariff.

Reasonable estimates will also be required in the year following the movement Year (t), given that a full year of actual data will not be available when setting the prices in the next year.

J.4 Value of p_{ik}^{t} when customers are transferred by the DNSP to an alternative tariff

As for the introduction of new network tariff/s and/or network tariff component/s, the p_{ik}^{t} for the corresponding origin network tariff component/s will be used as the p_{ik}^{t} for the new network tariff component/s for the affected quantities (or the d_{k}^{t} in the side constraint formula).[934]

Table J.2: Example 2 – reasonable estimates for re-assigning some customers from the domestic flat rate tariff to the domestic TOU tariff

Network tariff	Customer (number)	Billed consumption (MWh)			
		Non-TOU	Peak	Shoulder	Off-peak
Time of use (existing)	10 000		25 000	20 000	25 000
Domestic (existing)	(10 000)	(70 000)			

Assumption: Only some customers from the domestic tariff will be moved to the new TOU tariff (10 000 customers with a consumption of 70 000 MWh). Both tariffs remain in existence and will have remaining customers on the tariffs.

933 Each customer has a standard network connection contract with its DNSP and a separate contract with its respective retailer who manages the relationship with the DNSP on the customer's behalf.

934 This is only required for movements that occur in Year t+1, not for movements in Year t.

Table J.3: Example 2 (cont) – parameters in the WAPC and side constraint formula for re-assigning some customers from the domestic flat rate tariff to the domestic TOU tariff

Tariffs		p_{ik}^{t-1}	p_{ik}^{t}	q_{ik}^{t-1}
Domestic				
Fixed charge	$ pa per customer	$30	$32	(25 000 existing – 10 000) =15 000 customers
Variable rate	c/kWh	0.04	0.05	(200 000 existing – 70 000) = 130 000 MWh
Domestic TOU – existing customers				
Fixed charge	$ pa per customer	$22	$25	5 000 existing
Peak rate	c/kWh	0.09	0.095	10 000 MWh existing
Shoulder rate	c/kWh	0.05	0.05	10 000 MWh existing
Off-peak rate	c/kWh	0.02	0.025	10 000 MWh existing
Domestic TOU – customers being transferred				
Fixed charge	$ pa per customer	$30 (as per domestic)	$25	10 000 customers
Peak rate	c/kWh	0.04 (as per domestic)	0.095	25 000 MWh
Shoulder rate	c/kWh	0.04 (as per domestic)	0.05	20 000 MWh
Off-peak rate	c/kWh	0.04 (as per domestic)	0.025	25 000 MWh

J.5 The AER's assessment of reasonable estimates

When assessing the reasonableness of quantity estimates provided, the AER will take the following information into account:

1. the actual audited quantities sold in relevant units under the origin network tariff in previous years
2. a forecast of the number of distribution customers that the DNSP states will move to the new network tariff and/or network tariff component, and the reasons for the move
3. a forecast of the number of distribution customers that the DNSP expects will remain on the origin network tariff
4. a forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that are to be moved to the new network tariff and/or network tariff component
5. a forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that will remain on the origin network tariff

6. a forecast of the distribution tariff, and associated revenue, the DNSP expects will be payable by those distribution customers that will be moved the new network tariff and/or network tariff component

7. a forecast of the distribution tariff, and associated revenue, the distributor expects will be payable by those distribution customers that will remain on the origin network tariff

8. the materiality of the reasonable estimates

9. further information as required by the AER.

Appendix K: Country Energy forecast capital expenditure

K.1 Introduction

This appendix is to be read in conjunction with chapter 7 of this draft decision. It sets out the AER's detailed considerations, reasoning and conclusions on Country Energy's proposed forecast capex allowance for the next regulatory control period which it is satisfied reasonably refects the capex criteria. The AER's general approach to assessing Country Energy's capex proposal and the relevant regulatory requirements are described in chapter 7. This appendix includes:

- an overview of Country Energy's capex proposal
- specific comments on the proposal from stakeholders
- the review and findings of the AER's consultant, Wilson Cook
- the issues and the AER's considerations and reasoning including a discussion of proposed capex by category
- the AER's conclusions and estimate of the efficient capex allowance for Country Energy for the next regulatory control period, which it is satisfied reasonably reflects the capex criteria.

K.2 Country Energy proposal

Country Energy proposed a capex allowance totalling $4008 million ($2008–09) for the next regulatory control period. Table K.1 and figure K.1 outline Country Energy's actual and proposed capex by category.[935]

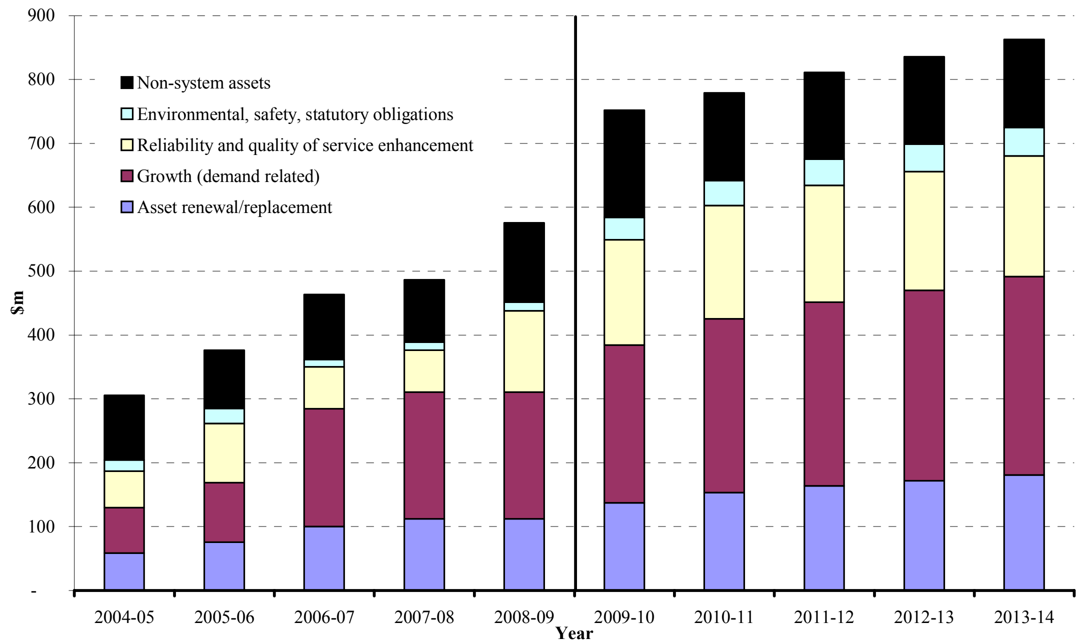
[935] Country Energy detected an error in its non–system capex modelling following the submission of its regulatory proposal. The total forecast capex was subsequently revised downwards by $32 million and the corrected figures are presented in table K.1. Note these figures do not reconcile with those presented in Country Energy's regulatory proposal.

Table K.1: Country Energy's capex proposal by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Growth	247.3	272.3	287.6	298.5	310.7	1416.5
Asset renewal/replacement	137.2	153.3	163.6	171.5	180.6	806.1
Reliability and quality of service enhancement	164.2	177.0	182.9	185.7	188.9	898.9
Environmental, safety and statutory obligations	35.5	39.0	41.3	42.9	44.6	203.3
Total system	584.2	641.7	675.4	698.6	724.9	3324.6
Non–system assets	167.8	137.3	130.6	123.4	124.6	683.6
Total	752.0	779.0	806.0	822.0	849.5	4008.4

Source: Country Energy global capex model; additional information provided 21 July 2008.
Note: Totals may not add up due to rounding.

Figure K.1: Country Energy's actual and proposed capex by category ($m, 2008–09)



Source: Country Energy regulatory proposal, RIN template 2.2.1. Data for 2004–09 converted to 2008–09 dollars.

Country Energy noted its proposed capex for the next regulatory control period is approximately double the amount expected to be spent in the current regulatory control period. Country Energy's increased capex requirement is driven by network demand growth, renewal and replacement due to deteriorating and ageing infrastructure, augmentation required to meet reliability and other obligations, and non–system expenditure requirements.[936]

The value of growth related capex is forecast to increase by around 90 per cent from the current regulatory control period, and will comprise approximately 35 per cent of the total capex requirement. Country Energy noted this is driven by a forecast annual growth rate of summer and winter peak demand of 3.0 per cent and 1.8 per cent respectively. The network is expected to shift from a winter to a summer system peak during 2012–13. Country Energy submitted that its growth related capex is generally targeted at reinforcing the network in corridors of strong economic growth, high density industrial areas and where step load connections occur.[937]

Country Energy proposed a value of renewal and replacement expenditure that is forecast to increase by around 76 per cent from the current regulatory control period, and will comprise around 20 per cent of the forecast capex program. It noted programs and initiatives planned for the next regulatory control period will focus on distribution lines and cables, sub–transmission lines and cables, substations and transformers and customer metering and load control.[938]

Country Energy proposed $191 million in reliability and quality enhancements which represents an increase of around 120 per cent from the current regulatory control period. This program is largely being driven by the need to comply with the NSW Design Reliability and Performance licence conditions which were introduced in 2005 and revised in 2007. Expenditure in this category for the next regulatory control period includes reinforcement of the distribution network to N-1 standards, remediation of individual poor performing feeders and improvements to average feeder performance.[939]

For the next regulatory control period, Country Energy forecast a 157 per cent increase in expenditures to satisfy environmental, safety, infrastructure security and legal requirements. This is largely being driven by improvement of substation fencing security, and rectification of overhead lines that do not meet new minimum clearance requirements, specifically for lines crossing navigable waterways.[940]

Country Energy forecast expenditure on non–system assets to increase by 31 per cent from the current regulatory control period. This category represents approximately 18 per cent of the total capex proposal for the next regulatory control period. It attributed this expenditure to the need to improve information systems, purchase of heavy plant and light vehicles, and growing accommodation requirements at field service centres and regional offices. It applied real cost escalation to its non–system capex.[941]

Country Energy developed the capex forecasts using an assumption of 2006–07 as an efficient base year. Country Energy applied a bottom-up method to forecast its capex requirements for individual sub–transmission and zone substation projects, and

[936] Country Energy, *Regulatory proposal*, p. 87.
[937] Country Energy, *Regulatory proposal*, p. 96.
[938] Country Energy, *Regulatory proposal*, p. 111–118.
[939] Country Energy, *Regulatory proposal*, p. 124–127.
[940] Country Energy, *Regulatory proposal*, p. 119.
[941] Country Energy, *Regulatory proposal*, p. 139–143.

applied unit rates observed during 2006–07. For distribution network capex, Country Energy has used a top down approach based on real 2006–07 base year costs to estimate investment requirements on the basis of the projected growth rate in customer connections, historical expenditures and average replacement costs for each asset class.[942]

Country Energy developed its capex programs and forecasts in accordance with its Network Asset Management Plan. Country Energy submitted that its forecasts are substantiated by robust engineering models, examination of factors driving changes in expenditure, comparison with historical expenditures and efficient quantities and unit prices.[943]

K.3 Submissions

The AER received one submission relating specifically to Country Energy's planned capex for the next regulatory control period, from the Energy Markets Reform Forum (EMRF).

The EMRF submitted that Country Energy has consistently expended an increasing amount of capex over the past decade, largely in line with growth trends. However, it submitted that the capex forecast for the next regulatory period exceeds the forecast demand growth by some $1.3 billion.[944]

Stakeholders made no further comments that specifically related to Country Energy's capex proposal. Comments relating to the NSW DNSPs' capex proposals generally are addressed in chapter 7 of this draft decision.

K.4 Consultant review

The AER engaged Wilson Cook to provide an independent assessment of Country Energy's capital governance framework and capex proposal.

As part of its assessment, Wilson Cook evaluated the documentation provided by Country Energy in its revenue proposal, sought additional information on specific projects and undertook follow–up discussions with Country Energy. From its review of Country Energy's forecast capex proposal, Wilson Cook found that:

- the key factors driving the system capex program are; growth, the need to comply with the NSW licence conditions for supply security and reliability, and the need to increase the rate of replacement of aged network assets[945]

- the system capex projects were reasonable in both scope and cost, however the proposed level of non–system capex appears too high[946]

942 Country Energy, *Regulatory proposal*, p. 91.
943 Country Energy, *Regulatory proposal*, p. 88.
944 EMRF, p. 17.
945 Wilson Cook, letter to AER, 11 Novemver 2008.
946 Wilson Cook, letter to AER, 11 Novemver 2008.

- the application of weighted real price escalators inflators for individual inputs was reasonable in principle, with the exception of real cost escalations applied to non–system expenditures.[947] However, Wilson Cook did not express a view on the reasonableness of the input assumptions regarding future cost movements. Nor did it verify that the methodology had been applied in the stated manner.[948]

- Country Energy has put forward a reasonable implementation strategy and there are no reasons to conclude that the necessary resources could not be mobilised to implement the capex program.[949]

In forming a view on Country Energy's forecast capex, and under the terms of reference, Wilson Cook considered the following key factors:[950]

- prudence and efficiency of the proposed expenditures[951]

- external obligations imposed on Country Energy

- consistency with demand forecasts proposed by Country Energy and reviewed by the AER

- unit costs, escalation rates and methodologies for materials cost estimation

- expenditure drivers including the need to address demand growth, ageing assets and safety and environmental issues

- appropriateness and consistent application of policies and procedures.

From its review, Wilson Cook concluded that Country Energy's forecast system capex was reasonable in both scope and cost.[952] However, it considered its level of non–system capex required adjustment and has recommended a reduction of 16 per cent ($112 million) to this expenditure category.[953] Wilson Cook's detailed considerations and rationale for this reduction are set out at section K.5 of this appendix. Table K.2 sets out the adjustments proposed by Wilson Cook.

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947 Wilson Cook, volume 4, pp. 16, 29.
948 Wilson Cook, volume 4, p. 16.
949 Wilson Cook, email to AER, 18 October 2008.
950 Wilson Cook, volume 1, pp 7–12.
951 Wilson Cook, volume 1, p. 9. Where Wilson Cook has considered there was an appropriate balance between the factors it considers comprise 'prudence' and 'efficiency', it has concluded in its report that the expenditure is reasonable.
952 Wilson Cook, volume 4, pp 15–16.
953 Wilson Cook, volume 4, p 33.

Table K2: Wilson Cook's recommended forecast capex allowance for Country Energy ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy proposal	752	779	806	822	849	4008
Adjustments to non–system assets						
IT systems	–16	–12	–12	–13	–13	–66
Land and Buildings	–7	–4	–3	–3	–3	–21
Corretion for capitalisation of tap changer setting work	–2	–2	–2	–2	–3	–12
Real cost escalation for non–system capex	–3	–4	–5	–6	–7	–25
Wilson Cook recommendation	724	757	784	798	823	3885

Source: Country Energy, *global capex model*; Country Energy, *additional information provided to the AER*, 21 July 2008; Country Energy, *remodelled data,* 18 November 2008; Wilson Cook, volume 4, p. 34.
Note: Totals may not add due to rounding.

K.5 Issues and AER considerations

This section presents the AER's consideration of the following aspects of Country Energy's proposal:

- its policies and procedures
- its cost estimation processes
- the application of input cost escalators
- proposed expenditure by major category
- the deliverability of the proposal

K.5.1 Policies, procedures and methods

This section examines whether Country Energy's capex planning practices are appropriate and provide a framework that is likely to result in prudent and efficient investment decisions. The AER considers that assessing these practices in this manner is relevant for determining whether the AER is satisfied that its forecast capex reasonably reflects the capex criteria.

Country Energy proposal

Country Energy submitted that it has a capital governance framework and processes in place for capital (and operational) planning and expenditure, and to ensure that the intended program of capital works is delivered in a prudent manner.[954] Country Energy submitted that its governance of capital projects is based on three elements:[955]

- annual capital budgeting process
- approval of capex in accordance with Country Energy procedural guidelines
- capital governance structures and processes within the respective divisions to monitor capex.

Country Energy's capital governance structure includes:

- Network Services Program Management Office which governs network capex
- Corporate Service Program Management Office, governing all capex related to the corporate services functions including information services
- Information Communication Technology Council which governs all information services related capex across Country Energy
- Property Services Capital Works Review Panel which governs all property related capex.

Country Energy submitted that the capital investment program is identified through rigorous annual business planning processes and selection of cost effective solutions reflecting Country Energy's network characteristics, asset performance and condition, demand forecasts, service targets and compliance obligations.[956] It submitted that major investment opportunities and expenditures are reviewed to establish need, and ensure consistency with corporate objectives and the Network Asset Management Plan and least cost solutions. Major projects are incorporated into Country Energy's annual business plan which is approved by Country Energy's Board.[957]

Country Energy submitted that its capex performance is monitored against budgets by its executives through consolidated and divisional capex reports, as well as divisional performance reports, known as 'dashboards'.[958]

Country Energy submitted its capital investment approach is consistent with the unique challenges and operating factors affecting its network and industry best practice, including:[959]

- best practice asset management strategies and procedures
- employment of risk management techniques

954 Country Energy, *Regulatory proposal*, p. 76.
955 Country Energy, *Regulatory proposal*, p. 76.
956 Country Energy, *Regulatory proposal*, p. 76.
957 Country Energy, *Regulatory proposal*, p. 76.
958 Country Energy, *Regulatory proposal*, p. 76.
959 Country Energy, *Regulatory proposal*, p. 76.

- asset investment and decision tools
- implementation of comprehensive asset information and management systems
- external contracting of non-core business activities through competitive tendering and performance contracts
- governance and business processes for setting and implementing capital and operating budgets, and
- business reporting and general performance management.

Country Energy developed its capex programs and forecasts in accordance with its Network Asset Management Plan. This key planning document consolidates Country Energy's detailed strategic planning documents including:[960]

- Capital Investment Strategic Plan which comprises the Network Augmentation Plan; Reliability, Quality and Security of Supply Management Plan, and the demand management Strategic Plan
- Asset Renewal Management Plan
- Asset Maintenance Management Plan
- safety plans.

Consultant review

Based on its review, Wilson Cook concluded that Country Energy had followed reasonable policies and procedures, including the identification of need and least cost solutions when making investment decisions. Wilson Cook further concluded that:[961]

- Country Energy's planning team followed current international planning practice and had adopted sound network planning concepts and policies
- Country Energy considered zone substation diversity and load transfers when planning its zone substation augmentation
- non–network and demand side alternatives were considered as potential alternatives to network augmentation and were provided for in Country Energy's procedures
- Country Energy appeared to be using appropriate methods for the construction and installation of its assets
- the particular types of assets to be used in the capex program during the next regulatory control period are appropriate for the purpose.

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[960] Country Energy, *Regulatory proposal*, p. 73.
[961] Wilson Cook, volume 4, p. 15.

AER considerations

The AER reviewed the application of Country Energy's capital planning and evaluation processes in the context of a sample of projects from the proposed capex program. The review principally involved assessing whether Country Energy's policies and procedures were appropriate, and whether or not they were applied in the manner stated by it. From this review, and considering advice provided by Wilson Cook, the AER is satisfied that Country Energy observed appropriate processes and procedures in determining the scope, timing and need for its proposed network system capex projects.

The AER is satisfied that these processes demonstrate a level of assurance and good practice that supports the assertion that Country Energy's system capex proposal is based on an effective and efficient identification of investment needs. The AER considers this to be relevant in determining whether Country Energy's forecast capex reasonably reflects the capex criteria of the transitional chapter 6 rules.

K.5.2 Cost estimation processes

This section examines the methods adopted by Country Energy to estimate costs for identified investment needs in the context of determining whether the AER is satisfied that its forecast capex reasonably reflects the capex criteria.

Country Energy proposal

Country Energy's capex forecasts have been developed using an assumption of a 2006–07 efficient expenditure base year. Country Energy has applied a bottom up method using historic actual unit rates from its internal cost estimation systems to forecast its capex requirements for sub–transmission and zone substation projects. For distribution network expenditure, a top-down approach has been applied (based on real 2006–07 base year costs) to estimate investment requirements on the basis of the projected growth rate in customer connections, historical expenditures and average replacement costs for each asset class.[962]

Country Energy engaged SKM to produce independent estimates of the modern equivalent asset unit rates applied in its 2002 asset valuation, in 2007 terms. However, Country Energy submitted that SKM's unit rates do not capture all relevant indirect and overhead costs that it must incur.[963]

Country Energy has not applied the SKM unit rates in developing its capex forecasts, rather, it has employed its internal cost estimation system, which draws on a frequently updated database of historic actual unit costs for various works. Country Energy submits that its own current unit costs are efficient and competitive with respect to the market, and other similar utilities.[964]

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962 Country Energy, *Regulatory proposal,* p. 91.
963 Country Energy, *Regulatory proposal*, p. 86.
964 Country Energy, *Regulatory proposal*, p. 86.

Country Energy submitted that its forecasts are substantiated by robust engineering models, examination of factors driving changes in expenditure, comparison with historical expenditures and efficient quantities and unit prices.[965]

Consultant review

The AER engaged Wilson Cook to develop independent forecasts of unit costs in advance of receiving the DNSPs' proposals. This was required to enable comparison with the costs that the DNSPs applied when preparing their expenditure forecasts. Wilson Cook advised this was not possible as the DNSPs used various methods for cost estimation—generally relying on the actual cost of completed work, internal costing programs or independent review—and not on unit costs of a type that could be compared.[966]

Wilson Cook acknowledged the work conducted by SKM, but did not place any weight on this in its assessment of Country Energy's cost estimates, as it considered the work only constituted an updating of the unit rates used in its asset valuation from 2002, to 2007 levels. Wilson Cook expressed to Country Energy that this would not be a suitable method of determining actual construction costs for its capex estimates and would not necessarily give comparable costs.[967] Based on its review, Wilson Cook accepted Country Energy's cost estimates as reasonable for the scope of work concerned.[968]

AER considerations

Based on its review of Country Energy's cost estimation processes, and advice from Wilson Cook, the AER concludes that Country Energy's unit cost estimates, and the methodology used to develop them, reflect a realistic expectation of cost inputs required to meet the capex objectives, and are likely to result in efficient cost forecasts. In forming this view the AER has noted:

- Country Energy's unit rates are taken from its internal estimating system, which is regularly updated based on actual costs of works completed. The internal estimation system appears to be capable of informing detailed bottom-up cost estimates

- It is reasonable for Country Energy not to rely on the unit rates developed by SKM for the following reasons:

  - the SKM unit rates were developed for the purpose of illustrating differences between estimated unit rates in 2002 and 2007 rates, and for providing an updated asset valuation estimate based on these differences

965 Country Energy, *Regulatory proposal*, p. 88.
966 Wilson Cook, volume 1, p 10.
967 Wilson Cook, volume 4, p. 16.
968 Wilson Cook, volume 4, p. 16.

- in some cases the updated 2007 SKM unit rates were developed by applying simple real cost escalation to 2002 values, rather than from its data base of observed contract values[969]

- SKM considered that in some cases it considered Country Energy's unit rates potentially understated the value of the capital works, for example, zone substations

- the majority of larger investment works (such as zone substation and sub–transmission lines) are subject to competitive tender processes which could be expected to reflect efficient costs, which are captured by Country Energy's in the estimating system database

K.5.3 Application of input cost escalators

This section examines whether the cost escalators used by Country Energy to develop its capex proposal reflect a realistic expectation of input costs required to meet the capex objectives, in the context of determining whether the AER is satisfied that Country Energy's forecast capex reasonably reflects the capex criteria.

Country Energy proposal

Country Energy applied real cost escalators to its capex program based on forecasts for labour, materials and construction costs developed by the Competition Economists Group (CEG).[970] By applying weightings to individual input cost factors, these forecasts are used to build up forecasts for key equipment categories, for example transformers, switchgear, substations and cables. These forecast cost movements are then used to derive expected future costs for individual capital projects and programs based on the infrastructure required for these works.

Country Energy applied a weighted average real cost escalator to its overall non–system capex program.[971]

Country Energy's proposed real cost escalations are illustrated at table K.3. The impact of Country Energy's input cost escalators is illustrated in table K.4.

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969 Country Energy, *Regulatory proposal*, appendix C.
970 Country Energy, *Regulatory proposal*, appendix C.
971 Country Energy, *Regulatory proposal*, p. 87.

Table K.3: Country Energy's proposed escalations (per cent, real)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Labour	3.6	3.9	1.9	2.8	3.5	3.7
Aluminium	3.5	–0.5	–0.2	0.3	0.0	0.0
Copper	–3.7	–6.3	–4.2	–2.8	–3.1	–3.1
Steel	0.1	0.3	0.2	0.2	0.2	0.2
Crude oil	12.3	–3.8	–1.3	–0.5	–2.0	–0.9
Construction	2.1	0.9	0.7	1.1	1.9	2.6
Land	4.1	4.1	4.1	4.1	4.1	4.1
Producer's margin	5.4	6.1	7.6	0.0	0.0	0.0

Source: Country Energy, additional information, 21 July 2008.

Table K.4: Impact of Country Energy's cost escalator factors

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Base capex ($m 2006–07)[a]	702.4	722.2	745.0	758.8	774.4	3702.9
Escalation adjustment	10.0	19.4	27.6	36.8	47.0	141.0
Inflation adjustment	42.4	44.1	46.0	47.3	48.9	228.8
Productivity saving	–2.8	–6.9	–7.2	–7.5	–7.7	–32.2
Total capex with real cost escalators ($ million 2008–09)	752.0	779.0	811.4	835.6	862.5	4040.5

Source: Country Energy, additional information, 21 July 2008.
Note: Totals may not add due to rounding.
(a) Base capex figures are phased and include corporate on cost.

Consultant review

Wilson Cook was not able to express a view on the reasonableness of the assumptions made regarding future cost movements (in particular the escalation factors determined by CEG). Wilson Cook was not able to verify that the method had been applied in the stated manner, therefore, it has relied on Country Energy's assurance that this has been applied in the stated manner.[972] Wilson Cook concluded that, given the scope of its review, the methodology and cost estimates proposed by Country Energy are reasonable.[973]

[972] Wilson Cook, volume 4, p. 16.
[973] Wilson Cook, volume 4, p. 16.

Wilson Cook concluded that it was not provided with the basis for establishing the weighted average non–system capex escalator and considers that, in general, there is no basis for applying real cost escalation to non–system capex.[974] Wilson Cook recommended a reduction of $25 million during the next regulatory control period to remove the effect of this escalation.[975]

AER considerations

The AER's detailed consideration and conclusions on the NSW DNSPs' proposed input cost escalators, and the methodologies underpinning those escalators, is set out at appendix N to this draft decision. While the AER has generally accepted the methodology for deriving input cost escalators, it has made some adjustments and used more recent data to provide a reasonable expectation of the input costs expected to be faced by Country Energy during the next regulatory control period.

The AER does not accept Country Energy's proposed escalator for timber poles, which attributes weightings to the indirect costs of wages and producer's margin. As discussed in appendix N, the AER does not consider it appropriate to apply a real escalator for a producer's margin and indirect labour costs on any input cost component. Consequently, those corresponding components of capex identified in Country Energy's proposal will be escalated at CPI only.

The AER notes that in forecasting its capex requirements for the next regulatory control period, Country Energy applied a weighted average annual real cost escalator of 1.4 per cent to its forecast non–system capex program. This escalator is based on the weighted average composition of the forecast non–system capex program, reflecting general wages (27 per cent), producer's margin (10 per cent), land and easements (14 per cent) and CPI (50 per cent).

The AER reviewed Country Energy's application of its real cost escalator for non–system capex and considers it reasonable given the composition of its forecast non–system expenditure program, with the exception of the inclusion of a producer's margin weighting. The AER has amended Country Energy's weighted average cost escalator for non–system capex to reallocate weightings attributed to producer's margin to CPI escalation only. The effect of this remodelling on the forecast non–system expenditure set out at table K.12.

The AER notes that the escalators applied by Country Energy to non–system land and buildings and wages are the same as those applied to system land and buildings and wages. The AER considers that this is reasonable as the costs reflected in these escalators do not discriminate between system and non–system expenditures.

The AER is not satisfied that Country Energy's cost escalation assumptions, which underlie its forecast capex, reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives, under the capex criteria at clause 6.5.7(c) of the transitional chapter 6 rules. The AER requested Country Energy to remodel its proposed capex program on the basis of the AER's decision on input cost escalation methodologies, as set out at appendix N of this draft decision, which resulted in an

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974 Wilson Cook, volume 4, p. 29.
975 Wilson Cook, volume 4, p. 33

$45.5 million net increase.[976] This reflects a $42.9 million decrease due to labour and materials escalators, which is more than offset by an $88.4 million increase due to the use of the AER's updated CPI data for inflating Country Energy's capex amounts from their base year estimates. For the purposes of this draft decision, the AER considers the remodelled amounts reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives. The effect of this remodelling is illustrated in table K.12.

K.5.4 Review by expenditure type

This section examines Country Energy's proposed expenditure by major investment category in terms of whether the scope, timing and costs reasonably reflect the efficient costs that a prudent operator in the circumstances of Country Energy, would require to achieve the capex objectives.

K.5.4.1 Augmentation capex

Country Energy proposal

Country Energy proposed augmentation expenditure of $1417 million ($2008–09) representing around 35 per cent of the total forecast capex program. Table K.5 sets out Country Energy's proposed augmentation capex by major categories.

Table K.5: Proposed augmentation capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Sub–transmission lines and cables	69.3	76.3	80.6	83.7	87.1	397.1
Distribution lines and cables	72.1	79.4	83.9	87.0	90.6	413.1
Substations	53.9	59.3	62.7	65.0	67.7	308.8
Transformers	18.4	20.3	21.4	22.3	23.1	105.6
Low voltage lines and cables	6.1	6.8	7.1	7.4	7.7	35.2
Metering and load control and communications	4.0	4.5	7.4	4.9	5.0	23.2
Land	4.1	4.6	4.8	5.0	5.2	23.7
Easements	19.2	21.0	22.3	23.1	24.0	109.7
Total	247.3	272.3	287.6	298.5	310.7	1416.5

Source: Country Energy Capex Model.
Note: Amounts are net of assumed productivity gains.

Country Energy's growth related capex is forecast to increase by around 90 per cent from the current regulatory control period. Country Energy submits that a key driver of this expenditure is a forecast annual growth rate of summer and winter peak demand of 3.0 per cent and 1.8 per cent respectively during the next regulatory

[976] The AER has not fully verified Country Energy's calculations for the purposes of this draft decision. As such this adjustment is indicative and will be confirmed for the AER's final decision and determination.

control period. It noted a shift from a winter to a summer system peak is expected during 2012–13. Country Energy submitted that its growth related capex is generally targeted at reinforcing the network in corridors of strong economic growth, high density industrial areas and where step load connections are expected to occur.[977] It submitted that it expects a stable annual load growth of 1.5 per cent during the next regulatory control period, however it expects air-conditioning penetration rates to continue to increase, driving increased summer peak loads.

Growth related programs proposed for the next regulatory control period include:

- New sub–transmission lines, and capacity and thermal upgrades to existing lines, looping of the network at the sub–transmission level and powerline route and easement acquisitions for future works. Country Energy submitted it will need to construct around 600 kilometres of new sub–transmission lines supplying substation loads greater than 15 MVA that do not currently provide N-1 security. It also submitted it will need to augment around 1000 kilometres of sub–transmission lines where peak demand has exceeded thermal ratings or voltage limitations, or there are other emerging constraints.[978]

- Construction of new zone substations and capacity upgrades to existing ones, installation of capacitor banks, upgrading of zone substation switchgear and protection systems and land purchases for future substation sites.[979]

- Construction of new urban distribution feeders and interconnections between existing ones to create a meshed network to address shortfalls in load transfer capabilities, upgrading of existing urban feeders, extension and uprating of existing rural feeders facing capacity constraints, new and upgraded distribution substations, and transformers and new augmented low voltage circuits. Country Energy submitted this distribution work program is aimed at reducing network constraints where feeder peak loading exceeds 80 per cent utilisation, or where feeders are expected to be loaded above emergency ratings.[980]

- Installation of customer metering for new residential, commercial and industrial developments and connections and installation of load control equipment.[981]

Consultant review

Wilson Cook noted that, unlike the other DNSPs, Country Energy has a very large territory served by numerous small networks and a commensurately large number of smaller capex projects, with the average project expenditure in this category being of around $5 million.[982] As a result of this, Wilson Cook adopted a sampling approach, focussing on the projects representing the largest investment during the next regulatory control period.

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977 The AER's assessment of Country Energy's demand forecasts is set out at chapter 5 of this draft decision.
978 Country Energy, *Regulatory proposal*, pp. 102–103.
979 Country Energy, *Regulatory proposal*, p. 103.
980 Country Energy, *Regulatory proposal*, p. 103.
981 Country Energy, *Regulatory proposal*, p. 104.
982 Wilson Cook, volume 4, p. 13.

Sub-transmission augmentation

Wilson Cook identified a sample of proposed sub–transmission projects, before identifying each project on sub–transmission line diagrams and reviewing the underlying reasons for the work with Country Energy's senior planning staff. Wilson Cook reviewed the following proposed sub–transmission projects:[983]

- replacement of the Russell Street substation
- network reconfiguration and replacement within the Wagga Wagga network
- strengthening of rural feeders in the Tamworth area
- substation replacement and network strengthening at South Coffs Harbour
- network development in the Port Macquarie area
- proposed bulk supply point at Stroud – Hawks Nest
- 132kV circuit works between Wellington and Narromine
- Cooma-Bega line conversion from 66 kV to 132 kV
- other projects in the Narrabri, Inverell, Hay-Hilston and Lismore areas.

At the request of Wilson Cook, Country Energy subsequently provided additional reports for Coffs Harbour sub–transmission planning, Lismore-Mullumbimby network development, the Port Macquarie area, Queanbeyan sub–transmission planning, Tamworth sub–transmission planning, Tea Gardens planning and Wagga Wagga sub–transmission planning.[984]

Based on its review of the information provided Wilson Cook concluded that the proposed work was unexceptional and supported adequately by documentation and explanation. It concluded that there were no grounds on which to deem that the costs applied to Country Energy's growth capex program were inefficient.[985]

Wilson Cook also noted that Country Energy has existing load control systems throughout the network and that, to date, few outside demand management proposals have resulted in technically and commercially feasible solutions to network development requirements.[986]

Distribution

Wilson Cook noted that distribution related expenditure of the type proposed by Country Energy represents routine work. Wilson Cook did note that the program includes the installation of meters and load control receivers for new connections,

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983 Wilson Cook, volume 4, p. 13.
984 Country Energy, additional information provided following site visit, 21 July 2008.
985 Wilson Cook, volume 4, p. 13.
986 Wilson Cook, volume 4, p. 14.

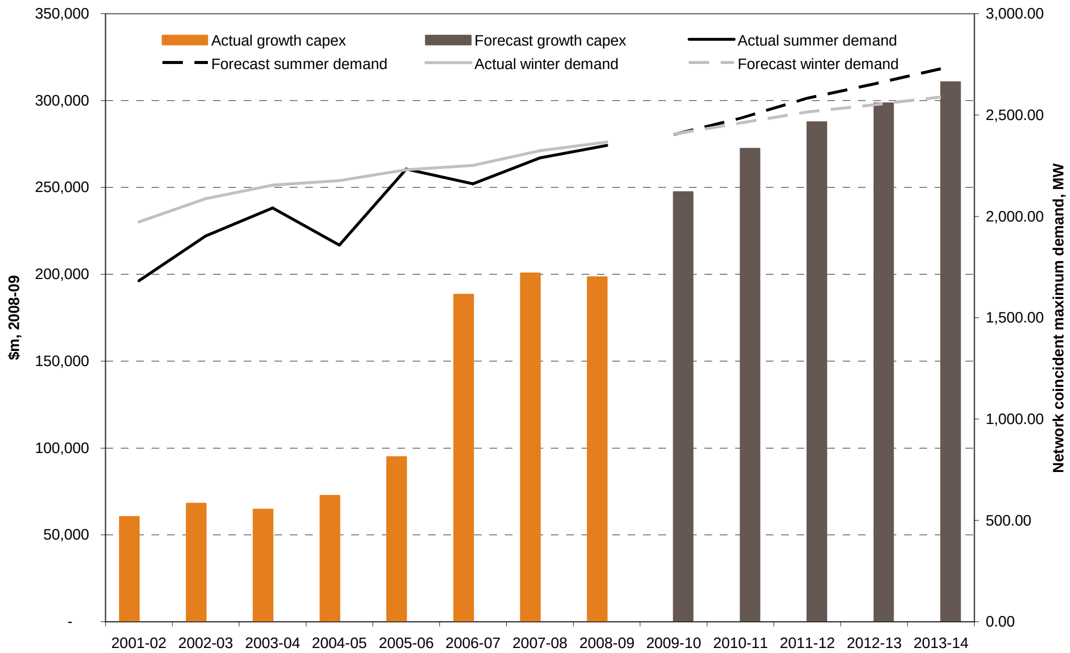
new frequency injection plant, SCADA[987] equipment at new zone and sub–transmission substations and the introduction of SCADA at sites presently without these facilities, particularly those that are inaccessible or remote. It considered that the communications expenditure is immaterial in the program and will be mainly concentrated in the southern region, where communications infrastructure is currently considered inadequate.[988]

Wilson Cook considered that Country Energy's expenditure under the categories of distribution lines, low voltage lines and customer metering and load control is in line with levels incurred during the current regulatory control period, and therefore considered the projections to be reasonable.[989]

AER considerations

In relation to the data presented by the EMRF, the AER has undertaken a comparison of changes in Country Energy's growth capex relative to peak demand growth, as illustrated in figure K.2.

Figure K.2: Country Energy's augmentation capex and peak demand



Country Energy's proposed augmentation capex displays a slow rising trend with a significant step increase from 2006–07, and a smaller increase in 2009–10 after which it increases steadily. This high level analysis does not identify any significant disjoint between proposed growth capex and peak system demand. The AER notes that other factors have contributed to Country Energy's growth capex such as the impact of licence conditions and customer numbers, and that demand at the disaggregated level is a better indicator of the key drivers of growth capex (although more difficult to compare at a high level).

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987 Supervisory Control And Data Acquisition

988 Wilson Cook, volume 4, p. 14.

989 Wilson Cook, volume 4, p. 14.

Wilson Cook and the AER have reviewed Country Energy's planning documentation for the sample augmentation projects identified above, and have discussed these projects with Country Energy engineering and planning staff. From this review, the AER is satisfied that Country Energy has:

- demonstrated the need for the proposed investments based on evidence of existing or emerging network constraints
- developed reasonable plans given the AER's conclusions on Country Energy's demand forecasts[990]
- considered alternative solutions including demand management options in its capital planning processes[991]
- supported its forecasts with sufficient analysis and documentation, and has applied its capital governance and planning policies, as stated, in developing the expenditure program.

The AER notes that while demand management options are considered in Country Energy's planning processes, to date, the quantity of economic demand management options available has been modest.

Based on these considerations, and the advice of Wilson Cook regarding other elements of Country Energy's augmentation expenditure noted above, the AER considers the proposed augmentation capex program reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives.

K.5.4.2 Replacement and renewal capex

Country Energy proposal

Country Energy proposed renewal and replacement expenditures of $806 million ($2008–09) representing around 20 per cent of the total forecast capex program. Table K.6 sets out Country Energy's proposed renewal and replacement capex by major categories.

990 The AER's considerations of Country Energy's demand forecast are set out at chapter 5 of this draft decision.

991 Further discussion on demand management projects and outcomes is set out at chapter 14 of the draft decision.

Table K.6: **Proposed renewal and replacement capex ($m, 2008–09)**

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Subtransmission lines and cables	15.5	17.1	18.2	18.9	19.8	89.4
Distribution lines and cables	62.2	70.0	74.9	78.8	83.2	369.1
Substations	23.4	26.0	27.9	29.3	31.0	137.5
Transformers	17.6	19.8	21.2	22.3	23.5	104.4
Low voltage lines	4.1	4.5	4.8	5.0	5.2	25.5
Customer metering	10.8	11.9	12.6	13.0	13.6	61.9
Communications	3.5	3.8	4.0	4.3	4.4	20.2
Renewal and replacement capex	137.1	153.3	163.6	171.5	180.6	806.1

Source: Country Energy, capex model.
Note: Totals may not add due to rounding.

Country Energy's renewal and replacement expenditure is forecast to increase by around 76 per cent from the current regulatory control period. Programs and initiatives planned for the next regulatory control period will focus on distribution lines and cables, sub–transmission lines and cables, substations and transformers and customer metering and load control. The core renewal program is expected to average around 1 per cent of total asset replacement cost per year during the next regulatory control period.[992] Country Energy submitted that its expenditure forecasts are conservative given increasing signs of deterioration, failure and ageing.[993]

Country Energy submitted that its approach to identifying and prioritising renewal requirements, and decisions to renew, are based on a range of factors including:[994]

- deterioration of condition identified during routine inspection and condition monitoring programs
- historical failure statistics where available
- assessed risk of failure
- asset reliability and quality of supply performance and compliance
- environmental, infrastructure security, or safety considerations
- asset age relative to accepted nominal engineering lives

992 Country Energy, *Regulatory proposal*, p. 110.
993 Country Energy, *Regulatory proposal*, p. 111.
994 Country Energy, *Regulatory proposal*, p. 110.

- analysis of the commercial investment opportunity
- implementation of specific initiatives.

Country Energy proposed to implement the following asset renewal and replacement projects and programs:[995]

- zone and sub–transmission substation power transformer replacements
- zone substation equipment driven by high maintenance requirements, poor reliability, lack of spares, age and condition, operational safety concerns and increasing fault levels. Country Energy submitted that this equipment typically requires replacement rather than refurbishment
- replacement of older steel and copper 66 kV and 33 kV overhead sub–transmission lines. Around 170 kilometres of 66kV overhead lines, and 40 kilometres of 33 kV overhead lines are expected to be replaced annually during the next regulatory control period
- replacement of distribution overhead lines, poles and pole-top components, due to deterioration
- replacement of distribution substations and transformers, largely due to damage incurred through lightening strikes and load growth
- replacement of high voltage distribution switchgear equipment and overhead service cables, meters and load control equipment and SCADA and communications equipment.

Consultant review

Wilson Cook noted that the forecast replacement and renewal capex reveals a generally consistent trend from historical expenditures in all categories except sub–transmission lines. It noted a step increase in this category due to the proposed replacement of conductors in poor condition which is to be performed in conjunction with growth related projects to achieve compliance with licence conditions.[996]

Wilson Cook reviewed each category of proposed renewal and replacement expenditure and concluded that the scope of the proposed works were reasonable and efficient.[997]

AER considerations

The AER's review of Country Energy's renewal and replacement capex principally involved the assessment of a sample of project proposal reports for zone substation power transformer replacements and capital works prioritisation matrices provided by Country Energy. This assessment demonstrated that these reports sufficiently evidence that Country Energy has considered the need for investments, probability

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995 Country Energy, *Regulatory proposal*, pp. 113–118.
996 Wilson Cook, volume 4, p. 19.
997 Wilson Cook, volume 4, p. 22.

and impacts of asset failure, alternative investment options, as well as demonstrating that Country Energy's capital governance and approval polices have been applied.

On this basis, and in conjunction with Wilson Cook's advice, as discussed above, the AER considers that Country Energy's proposed renewal and replacement programs are necessary to maintain the ongoing security and reliability of its network, and to meet reliability obligations. The AER is satisfied that this aspect of Country Energy's forecast capex reasonably reflects the efficient costs a prudent operator would require to achieve the capex objectives.

K.5.4.3 Reliability improvement expenditure

Country Energy proposal

Country Energy proposed reliability and quality enhancement capex of $899 million, representing 22 per cent of Country Energy's total forecast capex for the next regulatory control period. This expenditure represents an increase of around 120 per cent from that spent in the current regulatory control period. It stated this program is being driven by the need to comply with design planning and reliability criteria licence conditions, requiring reinforcement of the distribution network to N-1 standards, remediation of individual poor performing feeders and improvement of average feeder reliability.[998] Table K.7 sets out Country Energy's proposed reliability and quality improvement capex.

Table K.7: Proposed Reliability and quality improvement capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Subtranmission lines and cables	3.9	4.3	4.5	4.7	4.9	22.1
Distribution lines and cables	147.7	158.7	163.7	165.7	168.0	803.8
Substations	5.8	6.3	6.7	7.0	7.2	33.0
Transformers	4.3	4.7	5.0	5.2	5.4	24.4
Low voltage lines	1.8	2.0	2.0	2.2	2.2	10.2
Customer metering	0.9	1.0	1.1	1.1	1.2	5.3
Reliability and quality improvement	164.3	177.0	183.0	185.8	188.9	898.9

Source: Country Energy, capex model.
Note: Totals may not add due to rounding

Country Energy proposed five key reliability and quality of supply investment programs for the next regulatory control period:[999]

[998] Country Energy, *Regulatory proposal*, pp. 124–127.
[999] Country Energy, *Regulatory proposal*, p. 133–135.

- urban distribution reinforcement program to satisfy N-1 security of planning criteria for high voltage distribution feeders in regional centres (as set out in Country Energy's licence conditions)

- improving average feeder reliability performance of urban and short rural feeders, to a 20 per cent probability of exceeding the SAIDI (system average interruption duration index) and SAIFI (system average interruption frequency index) targets set in the licence conditions

- maintaining an average feeder reliability performance for long rural feeders, to meet the SAIDI and SAIFI targets set in the licence conditions

- improving individual feeder reliability performance for SAIDI and SAIFI towards the standards set in the licence conditions

- system wide steady-state voltage improvement program.

Individual feeder reliability improvement

Country Energy's proposed individual feeder reliability remediation program aims to rectify instances of non-compliance with licence conditions on an average of 110 poor performing feeder segments each year. On each feeder segment identified for remediation, the following works are proposed:

- replacement of bare overhead conductor and pole top hardware

- extensive recloser and sectionaliser installation

- construction or reinforcement of interconnecting feeder capacity to other feeders and construction of new small rural zone substations.[1000]

Urban distribution reinforcement program

Country Energy submitted that it has been in the process of implementing an N-1 capex program across its high voltage distribution networks in regional centres since the initial release of the NSW DRP licence conditions. These works have not however been completed due to uncertainty surrounding the changes to the licence conditions which now mandate an 80 per cent feeder capacity utilisation capacity standard. Country Energy submitted that, for this reason, a proportion of the urban distribution feeder reinforcement capital works are yet to be completed.[1001]

Country Energy submitted that it has been loading its distribution feeders to near 100 per cent of thermal rating, but must now limit loading to 80 per cent utilisation, in accordance with its licence conditions. To achieve this utilisation level, it submitted it will need to build additional transfer capacity through new lines and uprating of existing assets. Country Energy proposed five categories of expenditures under this program:

- construction of new urban distribution feeders

[1000] Country Energy, *Regulatory proposal*, p. 135.
[1001] Country Energy, *Regulatory proposal*, p. 133.

- construction of new interconnections between adjacent feeders
- capacity upgrading of existing urban distribution feeders
- installation of reclosers at the extremities of urban feeders to allow loop automation between adjoining feeders
- installation of fully enclosed gas switches.[1002]

Average reliability standards improvement program

Country Energy proposes to implement a new system wide works program over the next regulatory control period to achieve a sustainable step change in the average reliability performance across its network.[1003] This is driven by the requirements of the NSW DRP licence conditions to maintain minimum levels of SAIDI and SAIFI across its network, by feeder type. Country Energy's minimum average SAIDI and SAIFI reliability targets imposed by the licence conditions are set out in table K.8.

Table K.8: Country Energy's historical reliability performance against licence condition targets

Year ending June	2004	2005	2006	2007	2008	2009	2010	From 2011
SAIDI- Minutes per customer								
Urban feeder								
Actual	124	158	109	114	-	-	-	-
Licence target	n/a	n/a	140	137	134	131	128	125
Short rural								
Actual	293	276	317	239	-	-	-	-
Licence target	n/a	n/a	340	332	324	316	308	300
Long rural								
Actual	373	625	578	497	-	-	-	-
Licence target	n/a	n/a	750	740	730	720	710	700
SAIFI- Number per customer								
Urban feeder								
Actual	1.90	2.30	1.28	1.36	-	-	-	-
Licence target	n/a	n/a	2.00	1.96	1.92	1.88	1.84	1.80
Short rural								
Actual	2.86	2.51	2.71	2.47	-	-	-	-
Licence target	n/a	n/a	3.30	3.24	3.18	3.12	3.06	3.00
Long rural								
Actual	3.18	4.88	4.06	3.82	-	-	-	-
Licence target	n/a	n/a	5.00	4.90	4.80	4.70	4.60	4.50

Source: Country Energy, *Electricity Network Performance Report 2006–07*, p. 18, NSW DRP Licence Conditions.

Country Energy stated the proposed investment requirements have been developed using 'bootstrap' modelling techniques.[1004] The requirements are based on performance exceeding the NSW DRP licence conditions one in every 5 years (80 per cent probability of compliance) compared to current performance probability

[1002] Country Energy, *Regulatory proposal*, p. 134.
[1003] Country Energy, *Regulatory proposal*, p. 136.
[1004] Country Energy's modelling quantifies the likelihood of actual reliability exceeding the average SAIDI and SAIFI targets set in the licence conditions, by accounting for weather patterns and the occurrence of other normal, but random, events.

distribution, which is one in every two years, or only 50 per cent probability of compliance with the licence conditions.[1005]

Country Energy has noted that average reliability improvement issues will take many years to address and that the level of investment in system wide improvements is dependent on the assumed probability of non-compliance with the licence conditions targets. Country Energy proposed to increase its average reliability performance to a level where the probability of exceeding the mandated targets is 20 per cent by the end of the next regulatory control period.[1006] It submitted that, to achieve this, it must target a level of average SAIDI and SAIFI reliability that is less than the licence conditions mandate.[1007]

Country Energy submitted that this program of works will focus primarily on an extensive roll-out of reclosers to increase feeder segmentation and minimise the number of customers affected by outages on long feeders. The program will be conducted in addition to the proposed installation of reclosers on identified poor performing feeders and the installation of remote control high voltage enclosed gas switches in urban and short rural areas.[1008]

Quality of supply improvement program

Country Energy proposes to implement a range of initiatives to address voltage variations, voltage dips and swells, voltage unbalance, excessive harmonic voltages and television and radio interference. Country Energy proposes to implement the following initiatives:[1009]

- long-term capacity augmentation of rural feeders and transformer upgrades to address under voltage from incremental load growth
- long-term upgrading of undersized distribution transformers and dedicated customer connection assets to address under voltage from incremental load growth
- setting of voltage regulating relay settings and distribution transformer tap changer settings.[1010]

Consultant review

Wilson Cook noted that it has previously considered a similar proposal for individual feeder reliability improvement expenditures, in connection with Country Energy's 2006 pass-through application to IPART to recover expenditures associated with meeting the reliability licence conditions implemented in 2005. At that time, Wilson Cook concluded that the expenditure should be accepted based on an estimated

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1005 Country Energy, *Regulatory proposal*, p. 136.
1006 Country Energy, *Regulatory proposal*, p. 136.
1007 Country Energy, *Regulatory proposal*, p. 136.
1008 Country Energy, *Regulatory proposal*, p. 137.
1009 Country Energy, *Regulatory proposal*, p. 138.
1010 Wilson Cook and the AER queried Country Energy on the apparent capitalisation of this expenditure. Country Energy has confirmed that these works should be expensed rather than capitalised, during a meeting between AER, Wilson Cook and Country Energy on 16 September 2008.

refurbishment of 100 feeder segments per year. It noted it has no objection to the value of 110 feeder segments per year currently proposed by Country Energy.[1011]

Based on its consideration of Country Energy's pass through application, and the points made by it in its 2006 report to IPART, Wilson Cook accepted that Country Energy's proposed expenditure is prudent as best it could judge in the absence of a defined scope of the works. In drawing this conclusion Wilson Cook recognised that:[1012]

- Country Energy's proposal is an estimate of the cost of an unknown scope of work
- Country Energy still reports a large number of non-complying individual feeders, and that remedial work of this nature is required
- the proposed program is for 5 years of work and reflects an average annual investment of $26,000 per kilometre of line remedied.

Wilson Cook also noted that this expenditure amounts to an acceleration of Country Energy's replacement program and may have been better categorised as such. It also recommended that continuation of this expenditure after the next regulatory control period should not necessarily be accepted, given the other works planned by Country Energy.[1013]

In relation to Country Energy's other proposed reliability programs, Wilson Cook concluded:[1014]

- the expenditure associated with the urban reinforcement program is prudent and reasonable, based on its review of the underlying methodology
- in relation to average reliability programs, it could not express an opinion on the setting of targets which are more stringent (i.e. lower) than those mandated by the NSW DRP licence conditions, as it appears a matter of interpretation of those conditions. It noted the matter for the AER's consideration as different assumptions regarding targets would give rise to different levels of expenditure by the DNSPs in circumstances that would otherwise be the same. From its review, it considered the expenditure reasonable, given the method of compliance chosen by Country Energy
- the expenditure proposed for quality of supply improvements is reasonable, following confirmation that costs of relay and tap changer setting work has been expensed rather than capitalised.

AER considerations

Improving reliability performance is a key driver of Country Energy's capex in the next regulatory control period. The AER notes that Country Energy's average feeder

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1011 Wilson Cook, volume 4, p. 24.
1012 Wilson Cook, volume 4, p. 25.
1013 Wilson Cook, volume 4, p. 25.
1014 Wilson Cook, volume 4, p. 25–27.

reliability improvement capex is based on targeting a higher level of average reliability performance for urban and short rural feeders than it is required to achieve under the NSW DRP licence conditions in order to achieve compliance 80 per cent of the time. Expenditure levels vary in accordance with targeted performance levels.

The AER sought further information on targeted levels of compliance with respect to the associated costs and circumstances, including alternative targets.

Country Energy referred to analysis in its Network Asset Management Plan which identified that further improvements in individual feeder performance did not appear to be justified when viewed in the context of the additional cost and deliverability concerns. In particular, Country Energy noted that achieving an alternative, 95 per cent probability of compliance would involve addressing fundamental rural network design standards, including replacement of bare conductors, undergrounding and the construction of additional zone substations. It estimated that the cost of this work would be $219 million per year in capex, or an increase of 25 per cent to its total capex forecast compared to the work program to achieve 80 per cent compliance.[1015] Given the concerns expressed by stakeholders about the deliverability of Country Energy's proposed capex in the absence of this additional investment, the AER considers that Country Energy's conclusions reflect prudent and efficient investment.

The AER considers that Country Energy's proposed projects and programs are necessary to maintain the ongoing security and reliability of its network, and to meet statutory obligations, and reasonably reflect the efficient costs required by a prudent operator to meet the capex objectives. In reaching this conclusion, the AER has considered the advice of Wilson Cook with respect to the efficiency of the expenditure and also the analysis undertaken by Country Energy regarding the prudence of its targeted level of compliance with the licence conditions relating to average feeder reliability.

K.5.4.4 Environmental, safety and statutory obligations

Country Energy proposal

During the next regulatory control period, Country Energy forecast $203 million of capex to satisfy environmental, safety, infrastructure security and legal requirements.[1016] This expenditure represents 5 per cent of Country Energy's total capex proposal and a 157 per cent increase in similar expenditures from the current regulatory control period. Table K.9 sets out Country Energy's proposed capex under this expenditure category.

[1015] Country Energy, email to AER, 2 October 2008.
[1016] Country Energy, *Regulatory proposal*, pp. 118-123.

Table K.9: **Proposed Environmental, safety and statutory obligations capex ($m, 2008–09)**

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Distribution lines and cables	13.3	14.7	15.5	16.0	16.7	76.2
Substations	14.3	15.8	16.7	17.3	18.0	82.0
Low voltage lines	0.5	0.6	0.6	0.7	0.7	3.1
Customer metering	7.3	8.0	8.5	8.8	9.2	41.9
Total	35.4	39.0	41.2	42.8	44.6	203.3

Source: Country Energy, capex model.
Note: Totals may not add due to rounding.

This capex is partly being driven by improvement of substation fencing security, and rectification of overhead lines that do not meet new minimum clearance requirements, specifically for lines crossing navigable waterways. Key projects and programs of work under this category are:

- environmental programs including management of PCB[1017] waste, transformer oil containment, replacement of other oil filled plant in sensitive areas, improvements to depots and facilities to enhance environmental controls, replacement of ozone depleting substances with alternatives, and transformer noise mitigation, among others
- safety related programs including rectifying overhead powerlines to meet mandatory clearance requirements and installation of signage as required by industry codes (particularly related to overhead river crossings), rectification of private pole defects, replacement of two-pole distribution substations with inherent design faults recognised as a safety hazard, and others
- programs to ensure compliance with requirements of the NER and NEL, including power factor correction, installation of metering at all zone substations, and replacement of meters that do not satisfy prescribed accuracy tolerance requirements.[1018]

Consultant review

Wilson Cook reviewed Country Energy's proposed expenditure to satisfy environmental, safety and statutory obligations, and accepted this expenditure as reasonable.[1019]

1017 Polychlorinated Biphenyls. These chemicals are used as coolants and insulators in transformers and capacitors.
1018 Country Energy, *Regulatory proposal*, pp. 119–123.
1019 Wilson Cook, volume 4, p. 28.

AER considerations

Based on its own review of the proposed expenditures, and advice of Wilson Cook, the AER is satisfied that the proposed expenditure for environmental, safety and statutory obligations reasonably reflects the efficient costs required by a prudent operator to achieve the capex objectives. In particular, the proposed expenditure is required to achieve the capex objective that the DNSP comply with all applicable regulatory obligations or requirements associated with the provision of standard control services under clause 6.5.7(a)(2).

K.5.4.5 Non system capex

Country Energy proposal

Country Energy proposed non–system expenditures of $684 million ($2008–09) representing around 17 per cent of the total forecast capex program. Table K.10 sets out Country Energy's proposed non–system capex by major categories.

Table K.10: Proposed non–system capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
IT systems	63.6	48.9	49.4	50.0	50.6	262.6
Motor vehicles	60.4	52.2	46.6	38.4	39.5	237.2
Land and buildings	27.5	21.1	19.6	19.2	19.5	107.1
Furniture, fittings, plant and equipment and other	16.2	15.0	14.9	15.6	15.0	76.8
Total proposed non–system capex	167.8	137.3	130.6	123.3	124.6	683.6

Source: Country Energy, global capex model; additional information provided to the AER on 18 November 2008.

Country Energy's expenditure on non–system assets is forecast to increase by 38 per cent from the current regulatory control period. Country Energy attributed this increase in expenditure to the need to improve information systems, purchase of heavy plant and light vehicles and growing accommodation requirements for field service centres and regional offices.[1020]

IT expenditure

Country Energy proposed to spend $263 million on information technology systems during the next regulatory control period, which represents an increase of around 72 per cent from the current regulatory control period. The key proposed investments include:

- review and replacement of asset management systems to achieve a greater degree of systems integration across the network

[1020] Country Energy, *Regulatory proposal*, pp. 139–143.

- upgrading of network billing and customer information systems which Country Energy submits are outdated

- upgrading of network quality monitoring systems aimed at improving quality of supply to rural areas, and to assist in meeting licence conditions

- other expenditures including upgrading of core infrastructure and software, and providing additional IT resources for an increased workforce.[1021]

Motor vehicles

Country Energy proposed to spend $269 million on heavy plant and light vehicles during the next regulatory control period. Approximately 97 per cent of the forecast expenditure for light vehicles is due to replacement of existing fleet at 100 000 kilometres, in accordance with company policy, while the remainder represents additional fleet for an expanded workforce.[1022]

The proposed expenditure represents a significant increase from the current regulatory control period. Country Energy submitted that this increase is largely attributable to the implementation of a new elevated work platform and crane borer replacement program, resulting from a detailed condition assessment of these assets.

Land and buildings

Country Energy has proposed to spend $107 million on non–system land and buildings during the next regulatory control period. This represents an increase of 23 per cent from the current regulatory control period.

Country Energy submitted that a number of regional offices and field service centres are currently at, or nearing, capacity and cannot accommodate further expansion of the workforce and vehicles. It submitted that investments will be required in building modifications, rebuilds and extensions. Further expenditures are proposed to continue the program of depot refurbishments to provide a safer, more efficient and secure working environment.[1023]

Furniture, fittings, plant and equipment and other non–system capex

Country Energy has forecast to spend $76 million on these categories of capex during the next regulatory control period. Country Energy noted that this level of forecast expenditure is in line with current expenditures and activity levels.[1024]

Consultant review

Wilson Cook's review of Country Energy's non–system capex was based on a top-down approach using benchmarking techniques, and a bottom-up review of expenditure categories. In summary, Wilson Cook's benchmarking analysis found that Country Energy's non–system capex is 20–25 per cent above the other DNSPs

[1021] Country Energy, *Regulatory proposal*, pp. 140–142.
[1022] Country Energy, *Regulatory proposal*, p. 144.
[1023] Country Energy, *Regulatory proposal*, p. 143.
[1024] Country Energy, *Regulatory proposal*, p. 143.

sampled.[1025] Wilson Cook's benchmarking analysis is further discussed at chapter 7 of the draft decision.

Wilson Cook noted that Country Energy had applied a weighted average real cost escalator to its non–system capex base capex forecast. It concluded that, in general, there is no basis for applying real cost escalation to non–system capex, and recommended an adjustment to remove the impact of this from each category of non–system capex.[1026]

Wilson Cook's findings on each category of non–system capex are set out below.

IT expenditure

Wilson Cook noted that the proposed investment is for IT systems that are typical in a network business, however the scale and scope of the expenditure is large and well in excess of historical expenditure. It benchmarked Country Energy's proposed expenditure on a cost per customer, and cost per size basis and noted the proposal is considerably higher than other DNSPs.[1027]

Regarding Country Energy's proposed implementation of a new asst management system, Wilson Cook considered that the LogicaCMG report[1028] commissioned by Country Energy which constitutes the basis of costing and project justifications, contained no detailed financial justifications of the project in terms of service or efficiency benefits likely to be realised from the investment.[1029]

Wilson Cook recommended that an adjustment of at least 25 per cent be made to bring the expenditure to an efficient level, compared to industry norms. It noted that this adjustment would bring Country Energy's IT expenditure forecast to a level at the top end of the range for other DNSPs, on a cost per size basis.[1030]

Motor vehicles

Wilson Cook benchmarked Country Energy's forecast fleet expenditure against other DNSPs and found the proposed expenditure was similar, noting that this expenditure is driven by the wide coverage of its network. It reviewed Country Energy's supporting information and was satisfied that the policies and processes for replacement and purchasing were appropriate, however it recommended an adjustment to remove the effect of real cost escalation, consistent with other categories of non–system capex reviewed.[1031]

Land and buildings

Wilson Cook reviewed supporting information, including a spreadsheet outlining the proposed works. It noted that the estimates were the sum of both a detailed list of works, and an estimate of the additional building space required to accommodate an

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[1025] Wilson Cook, volume 4, p. 30.
[1026] Wilson Cook, volume 4, p. 29.
[1027] Wilson Cook, volume 4, p. 31.
[1028] Additional information provided to AER on 21 July 2007. Logica, *Analysis and recommendations for an asset management information system: Country Energy*, 25 March 2008.
[1029] Wilson Cook, volume 4, p. 31.
[1030] Wilson Cook, volume 4, p. 31.
[1031] Wilson Cook, volume 4, pp. 31–32.

expanded workforce. It therefore considered there was an element of double counting, as the detailed list contained additional buildings and some additions to create extra space. To address this, Wilson Cook recommended that the allowance for additional resources be reduced by 50 per cent ($21 million) over the next regulatory control period. Wilson Cook concluded that, apart from this adjustment–and the removal of real cost escalation–no other adjustments were required to the forecast.[1032]

Furniture, fittings, plant and equipment and other non–system capex

Wilson Cook reviewed this category of expenditure and noted that Country Energy is forecasting to spend less in the next regulatory control period than the current regulatory control period. Based on this, it considered the expenditure appropriate. Consistent with other categories of non–system capex, Wilson Cook recommended the removal of real cost escalation from this expenditure.[1033]

AER considerations

The AER has reviewed Country Energy's non–system capex proposal, taking into account additional information, and the advice of Wilson Cook. Based on this review the AER:

- does not consider it appropriate to recognise a producers margin weighting in applying a real cost escalator. The AER considers the weighting attributed to producer's margin should attract CPI escalation only and has amended Country Energy's weighted average escalator accordingly

- recognises that, when benchmarked in comparable terms against other DNSPs, Country Energy's proposed IT expenditure appears inefficiently high, and considers it has not been sufficiently justified in financial terms. The AER accepts the advice of Wilson Cook that this category should be reduced by 25 percent to bring it to a level, comparable with other DNSPs

- has reviewed Country Energy's property capital works schedule and its final expenditure forecasts, and has identified potential double counting in its forecasts of building and accommodation requirements. Specifically, Country Energy's total network property forecasts appear to be the sum of a base estimate from the capital works schedule and an allowance to reflect additional accommodation needs for estimated workforce expansion. The AER considers these additional accommodation needs are implicit in the detailed works schedule and do not need to be further reflected in forecasts. To correct for this the AER accepts Wilson Cook's recommendation that this expenditure category should be reduced by 50 per cent.

On this basis, the AER is not satisfied that Country Energy's forecast non–system capex reasonably reflects the capex criteria at clause 6.5.7(c), in particular the efficient costs that a prudent operator in Country Energy's circumstances would require to achieve the capex objectives.

[1032] Wilson Cook, volume 4, p. 32.
[1033] Wilson Cook, volume 4, p. 32.

After making the adjustments outlined above, the AER has estimated that a forecast non–system capex allowance reflective of $585 million reasonably reflects the capex criteria, specifically, the efficient costs that a prudent operator in the circumstances of Country Energy would require to satisfy the capex objectives. The AER's draft decision and adjustments to Country Energy's non–system capex are set out at table K.11.

Table K.11: AER conclusion on non–system capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy proposed capex	167.8	137.3	130.6	123.3	124.6	683.6
Wilson Cook / AER adjustments						
IT systems	–15.9	–12.2	–12.4	–12.5	–12.6	–65.6
Land and Buildings	–7.4	–4.1	–3.3	–3.0	–3.1	–20.8
Adjustments to real cost escalation	–1.3	–2.2	–2.4	–2.6	–3.0	–11.5
AER non–system capex	143.5	119.1	113.2	104.7	105.6	585.1

K.5.5 Deliverability of the forecast capex program

This section examines the methods proposed by Country Energy to deliver its proposed capital program within the next regulatory control period in the context of determining whether the AER is satisfied that Country Energy's forecast capex reasonably reflects the capex criteria

Country Energy proposal

Country Energy submitted that it has a resource plan to deliver its expanded capex program, by alleviating resource constraints during the current regulatory control period. It submitted it has commenced this process and has identified constraints and implemented strategies in the area of internal and external human resources and logistics.[1034]

Country Energy engaged Parsons Brinckerhoff (PB) to undertake an independent review of its capacity to deliver the increased capex program over the next regulatory control period.[1035]

PB examined Country Energy's existing capabilities and recommended eight strategies to increase its resource capabilities. These included the release of existing staff to undertake additional works, apprentice training programs, and productivity improvement opportunities.[1036] PB also noted that Country Energy has the ability to

[1034] Country Energy, *Regulatory proposal*, p. 81.
[1035] Country Energy, *Regulatory proposal*, appendix A.
[1036] Country Energy, *Regulatory proposal*, p. 29.

substantially increase its annual apprentice intake, creating opportunities to vary the balance of its labour resourcing strategies to optimally deliver the capex program.[1037]

PB concluded that Country Energy will be able to deliver all the additional proposed works within the envisaged time frame, providing that it profiles its investment timing to match the availability of labour throughout the next regulatory control period.[1038] Country Energy has acknowledged this recommendation and has 'phased' its capex across the next regulatory control period to reflect the profile of its expected resource capabilities. Country Energy has also proposed to implement the following resourcing strategies during the next regulatory control period:

- continued recruitment and establishing an adequate mix on internal and external resources to complete additional works
- continued intake of new apprentices and graduates from a wide range of disciplines
- targeting of qualified tradespeople and technical support from other related industries, including from interstate and overseas
- retention and attraction of employees through competitive wages
- contracting of external specialised services through publicly tendered contracts and development of strategic relationships with external service providers to match resource requirements to program resource demands
- ensuring effective internal contract management resources to administer increased project work undertaken by external providers
- increased motor vehicle and heavy fleet purchases
- continued improvement of corporate governance framework for capital investments.[1039]

Country Energy has also assumed an allowance for labour productivity gains of 10 per cent by 2011. The strategy recommended by PB to achieve these gains aims to increase the productivity of all trades qualified staff through improved work scheduling and clearly defined job specifications. [1040] PB noted that Country Energy had trialled this type of strategy in the mid-north coast and the outcomes have been excellent with the elimination of a substantial backlog of work without increasing the workforce.[1041] From 2011 onwards, Country Energy has assumed the 10 per cent productivity gain to be retained, however, no further improvements have been factored into expenditure forecasts for the remainder of the next regulatory control period.

[1037] Country Energy, *Regulatory proposal*, appendix A, p. 13.
[1038] Country Energy, *Regulatory proposal*, appendix A, p. 13.
[1039] Country Energy, *Regulatory proposal*, p. 29.
[1040] Country Energy, *Regulatory proposal*, appendix A, p. 13.
[1041] Country Energy, *Regulatory proposal*, appendix A, p. 13.

Consultant review

Wilson Cook reviewed Country Energy's implementation plans, and PB's assessment, and considered that there were no reasons to conclude that the necessary resources could not be mobilised to implement the program. It concluded that Country Energy had put forward a reasonable implementation strategy.[1042]

AER considerations

The AER notes that Country Energy's forecast capex program represents a significant increase compared to investment undertaken in the current regulatory control period.

Having considered Country Energy's forecast capex program and proposed implementation strategies, and the advice of Wilson Cook, the AER is satisfied that the deliverability of the forecast capex program will not be constrained by resource availability. The AER considers that Country Energy's approach to determining future resource requirements is sound and Country Energy's existing, and future, plans to ensure program deliverability are robust. The AER is also satisfied that the deliverability of Country Energy's forecast capex program is consistent with the capex objectives generally, and in so far as this aspect is concerned is satisfied it reasonably reflects the capex criteria.

The AER does have some concerns that the DNSPs will be seeking the same resources concurrently using overlapping delivery strategies, including with TransGrid. The AER notes the risk that Country Energy and the other NSW DNSPs may face financial resource constraints should the current credit crisis persist.[1043] Physical resource constraints are also likely to be addressed, to some extent, by an expectation that the Australian economy is entering a period of reduced activity which will see a decline in demand for resources from other sectors of the economy.

Given the AER's concerns about the concurrent levels of investment proposed for the broader NSW electricity network, the AER will carefully monitor Country Energy's performance on an annual basis and through its annual regulatory reporting reports will publish the actual capex spent by each of the NSW DNSPs, including any over or underspends.

K.6 AER conclusion

The AER has considered Country Energy's proposed forecast capex allowance and, for the reasons set out in this appendix, is not satisfied that the scope of the proposed capital projects and programs reasonably reflect the efficient costs, or a realistic expectation of the cost inputs a prudent operator, would require to achieve the capex

[1042] Wilson Cook, Email to Mike Buckley, 17 October 2008.

[1043] The AER notes that the NSW Government's Mini Budget 2008–09 provides for an $857 million reduction over three years in the borrowing capacity of the NSW DNSPs and TransGrid. The AER has assessed this financing constraint against the proposed capex programs from 2009–10 to 2011–12, and is satisfied that this need not adversely impact on the deliverability of the program. The reduction in the borrowing program represents a relatively small proportion of the capex program and its impact may be offset by increased internal efficiencies in each of the businesses and or by a change in the timing of dividend payments to the to the shareholder. See: <http://www.treasury.nsw.gov.au/__data/assets/pdf_file/0016/12706/08–09_Mini-Budget.pdf>

objectives as provided for in the capex criteria at clause 6.5.7(c) of the transitional chapter 6 rules.

In particular, the AER is not satisfied that the expenditure associated with Country Energy's application of input cost escalators, IT expenditure and land and buildings reasonably reflects a realistic expectation of the cost inputs required to achieve the capex objectives. The AER considers the following adjustments to Country Energy's capex proposal are required:

- $66 million (25 per cent) reduction to forecast IT expenditure
- $21 million reduction to non–system land and building expenditures to correct for apparent double counting.
- $12 million reduction to reflect that certain works (works relating to relay settings and tap changers) should not be capitalised
- $46 million net increase to reflect the application of modified input cost escalators to system and non–system capex (including updated CPI data) as determined in appendix N of this draft decision.

As the AER is not satisfied that the proposed capex allowance reasonable reflects the capex criteria, under clauses 6.5.7(d) the AER must not accept Country Energy's proposed forecast capex. Under clause 6.12.1(3)(ii) of the transitional chapter 6 rules, the AER is therefore required to provide an estimate of the capex for Country Energy over the next regulatory control period it is satisfied reasonably reflects the capex criteria, taking into account the capex factors. After making the adjustments listed above, this allowance is $3955. Table K.12 sets out the AER's draft decision on Country Energy's capex allowance for the next regulatory control period.

Table K.12: AER's draft decision on Country Energy's ex ante capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy proposed net capex	752.0	779.0	806.0	822.0	849.5	4008.4
Adjustment for incorrect capitalisation of tap changer setting expenditure	–2.4	–2.4	–2.4	–2.4	–2.5	–12.1
Adjustment for 25 per cent efficiency for IT expenditure	–15.9	–12.2	–12.4	–12.5	–12.6	–65.6
Adjustment for non–system land and buildings	–7.4	–4.1	–3.3	–3.0	–3.1	–20.8
Adjustments to cost escalators (including updated CPI)	16.2	16.5	12.0	5.3	4.5	45.5
AER capex allowance	742.6	776.8	799.9	809.3	826.7	3955.4

Appendix L: EnergyAustralia forecast capital expenditure

L.1 Introduction

This appendix is to be read in conjunction with chapter 7 of the draft decision. It sets out the AER's detailed considerations, reasoning and conclusions on EnergyAustralia's proposed forecast capex allowance for the next regulatory control period, which it is satisfied reasonably reflects the capex criteria. The general approach to assessing EnergyAustralia's capex proposal and the relevant regulatory requirements are listed in chapter 7. This appendix includes:

- an overview of EnergyAustralia's capex proposal
- specific comments on the proposal from stakeholders
- the review and findings of the AER's consultant, Wilson Cook
- the issues and the AER's reasoning and considerations, including a discussion of proposed capex by category
- the AER's conclusions and estimate of the forecast capex allowance for EnergyAustralia it is satisfied will reasonably reflect the capex criteria for the next regulatory control period.

L.2 EnergyAustralia proposal

EnergyAustralia has proposed a capex allowance of $8659 million ($2008–09) for the next regulatory control period. Tables L.1 and L.2 set out EnergyAustralia's proposed capex for distribution and transmission. Figure L.1 sets out EnergyAustralia's proposed capex by driver.

Table L.1: EnergyAustralia's distribution capex proposal ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
System assets						
Asset renewal/ replacement	487.2	592.9	653.5	663.5	798.2	3195.3
Growth (demand related)	498.0	582.3	604.4	560.1	536.5	2781.4
Reliability and quality of service enhancement	52.5	78.0	133.3	68.4	34.8	367.0
Environmental, safety, statutory obligations	53.2	50.8	87.4	94.0	68.1	353.6
Other	33.9	27.2	35.4	21.5	22.9	140.9
Sub–total	1124.7	1331.2	1514.1	1407.6	1460.6	6838.1
Non–system assets						
Business support	76.7	46.1	34.5	35.9	29.8	223.1
IT systems	118.3	55.5	62.6	40.1	42.9	319.4
Sub–total	195.0	101.7	97.1	76.0	72.7	542.5
Total	1319.7	1432.8	1611.2	1483.6	1533.3	7380.6

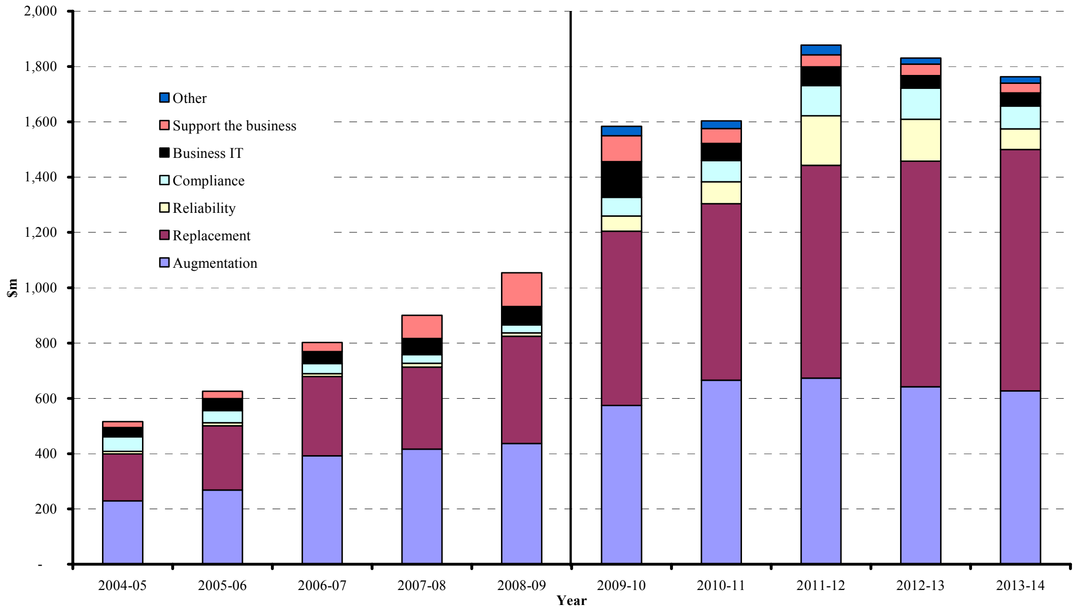
Source: EnergyAustralia, *Regulatory proposal*, RIN templates.
Note: Totals may not add up due to rounding.

Table L.2: EnergyAustralia's transmission capex proposal ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
System assets						
Augmentation	76.2	83.1	68.4	81.5	90.6	399.8
Replacement	143.5	46.0	116.8	152.5	74.6	533.4
Reliability	2.0	0.8	45.0	83.2	39.7	170.8
Compliance	14.7	26.1	22.5	18.6	14.6	96.5
Sub–total	236.3	156.0	252.7	335.9	219.5	1200.5
Non–system assets						
Business IT	10.9	6.6	4.9	5.1	4.2	31.7
Support the business	17.0	8.0	9.0	5.8	6.2	45.8
Other	0.0	0.0	0.0	0.0	0.0	0.0
Sub–total	27.9	14.5	13.9	10.9	10.4	77.5
Total	264.2	170.5	266.6	346.7	229.9	1278.0

Source: EnergyAustralia, *Regulatory proposal*, RIN template.
Note: Totals may not add up due to rounding.

Figure L.1: EnergyAustralia's capex proposal by driver ($m, 2008–09)



EnergyAustralia's capex proposal is more than double the amount expected to be incurred during the current regulatory control period. It justifies this significant increase on the basis of several key expenditure drivers, including:[1044]

- the worsening condition of its network assets and the need for their replacement. EnergyAustralia has a significant population of assets approaching or beyond their standard life—most notably 33kV gas and 132kV oil filled sub–transmission cables and 11kV switchgear.

- increases in peak demand growth and the need to augment its network. EnergyAustralia has forecast residential peak demand growth of 3.7 percent and non-residential peak demand growth of 2.2 percent. This represents an average peak demand growth of 2.8 per cent.

- expenditure required to meet mandatory investment criteria and minimum service quality standards set out by the NSW Government in the Design, Reliability and Performance licence conditions (NSW DRP).

EnergyAustralia's capex proposal has been developed through a series of investment plans that address investment at different voltage levels in its transmission and distribution network, and others that address specific types of investment.

Proposed investment in EnergyAustralia's transmission and subtransmission networks is addressed in a series of area plans developed for specific geographic regions (three regions at the transmission level and 25 at the subtransmission level). Each area plan proposes investment solutions for identified assets over a 20 year timeframe and encompasses all investment drivers in the area, such as peak demand growth, asset condition and reliability. The area plans address replacement requirements that have

[1044] EnergyAustralia, *Regulatory proposal*, p. 37.

synergies with other drivers (all other replacement requirements are covered by the replacement plan).

At the distribution network level EnergyAustralia utilises forecasting models, statistical analysis and asset population risk assessment to develop capital investment plans that are based on a single driver. Peak demand growth in the distribution network is addressed in the 11kV network development model and the low voltage capacity plan. Asset condition is addressed by the replacement plan (which also addresses components of the transmission and subtransmission networks not addressed by area plans). The reliability investment plan addresses service quality standards set by the NSW DRP licence conditions for the distribution network. The reliability investment plan assumes all investments in the area plans and replacement plans are made and identifies any further investment required to deliver service standards consistent with the NSW DRP licence conditions. Other investment plans include a duty of care plan, a customer connections plan and various system and business support plans.

Each of these investment plans identifies investment requirements that are costed in constant dollar terms. These costs have then been inflated by real cost escalators that reflect EnergyAustralia's expectation that costs will grow at a rate greater than CPI. The application of these escalators 'results in a substantial increase in costs over the period'.[1045]

L.3 Submissions

The Energy Markets Reform Forum (EMRF) argued that EnergyAustralia's proposed capex was significantly in excess of needs and 'at most should be some $4–5 billion for the period'.[1046]

The EMRF also considered that the AER must ensure that EnergyAustralia would be able to deliver its proposed capex for augmentation and replacement.

EnergyAustralia made a submission to address the concerns raised by interested stakeholders at the public forum held on 30 July 2008. In relation to capex, EnergyAustralia noted the strategies it has in place to deliver its capital program.[1047]

EnergyAustralia also made a submission addressing concerns raised by stakeholders in their written submissions regarding the magnitude of its proposed capex, deliverability of the proposed capital program, deferral of capex and cost escalation. The submission highlighted the parts of its regulatory proposal that addressed the issued raised by stakeholders in their written submissions.[1048]

Other specific issues raised by stakeholders are identified in the following sections. Comments relating to the NSW DNSPs' capex proposals generally are addressed in chapter 7 of this draft decision.

[1045] EnergyAustralia, *Regulatory proposal*, p. 78.
[1046] EMRF, p. 16.
[1047] EnergyAustralia, *Response to submissions*, p. 2.
[1048] EnergyAustralia, *response to submissions*.

L.4 Consultant review

The AER engaged Wilson Cook to provide an independent assessment of the efficiency and appropriateness of EnergyAustralia's capital governance framework and capex proposal.

As part of its assessment, Wilson Cook evaluated the documentation provided by EnergyAustralia in its revenue proposal, sought additional information on specific projects and undertook follow-up discussions with EnergyAustralia. Wilson Cook found from its review of EnergyAustralia's forecast capex proposal that:

- the primary factors driving the capex program were the continued growth in peak demand, the reliability and security of supply requirements in its licence conditions, and the replacement of aging assets
- the projects were generally prudent and efficient and there were no issues or problems that it considered were serious or likely to be systematic
- the cost estimates used for project costing were reasonable for the scope of work concerned
- the application of weighted real price escalators for individual inputs was reasonable in principle[1049]
- the capex program is deliverable.[1050]

Wilson Cook concluded that both the system and non–system capex proposed by EnergyAustralia were prudent and efficient within the limits of its review and that no adjustment of the total capex proposed by EnergyAustralia was needed for the purposes of its review.

In forming a view on EnergyAustralia's forecast capex, consistent with its terms of reference, Wilson Cook considered the following key factors:

- prudence and efficiency of the proposed expenditures
- external obligations imposed on EnergyAustralia
- consistency with demand forecasts as proposed by EnergyAustralia and reviewed by McLennan Magasanik Associates (MMA)
- unit costs, escalation rates and methodologies for materials cost estimation
- expenditure drivers including the need to address demand growth, ageing assets and safety and environmental issues

[1049] Wilson Cook did not express a view on the reasonableness of the input assumptions regarding future cost movements. Nor did it verify that the methodology had been applied in the stated manner.

[1050] Wilson Cook, volume 2, pp. 8–45.

- appropriateness and consistent application of policies and procedures.[1051]

L.5 Issues and AER considerations

This section presents the AER's consideration of the following aspects of EnergyAustralia's proposal:

- its policies and procedures
- its cost estimation processes
- the application of input cost escalators
- proposed expenditure by major category
- the deliverability of the proposal.

L.5.1 Policies and procedures

This section examines whether EnergyAustralia's capex planning practices are appropriate and provide a framework that is likely to result in prudent and efficient investment decisions. The AER considers that assessing these practices in this manner is relevant for determining whether the AER is satisfied that EnergyAustralia's forecast capex reasonably reflects the capex criteria.

EnergyAustralia proposal

EnergyAustralia stated that all capital investments are planned, assessed and authorised according to its capital governance process. The capital governance process is a five step process that involves:[1052]

1. confirming the need for the investment
2. developing project options to address the investment need
3. developing, scoping, costing and submitting for authorisation the most efficient option
4. executing the project
5. evaluating the project outcomes against its requirements.

EnergyAustralia used a two stage process to forecast its capital program.[1053] The first stage involved identifying network requirements at an investment driver level. The second stage used the identified investment needs for each driver as inputs to EnergyAustralia's strategic planning process. This second stage produced a series of investment plans that EnergyAustralia used as the basis of its capital forecast for the 2009–14 regulatory control period. The investment plans produced included:

[1051] Wilson Cook, volume 1, p. 7–12.
[1052] EnergyAustralia, *Regulatory proposal*, p. 101.
[1053] EnergyAustralia, *Regulatory proposal*, p. 56.

- three transmission area plans
- 25 subtransmission area plans
- a replacement plan
- an 11kV network development model
- a reliability investment plan
- a low voltage capacity plan
- a duty of care plan
- a customer connections plan
- system and business support plans.

Consultant review

Wilson Cook considered that EnergyAustralia had followed reasonable policies and procedures, including the identification of need and least cost solutions when making investment decisions.[1054] Wilson Cook further concluded that:

- EnergyAustralia's planning team followed current international planning practice and had adopted sound network planning concepts and policies
- EnergyAustralia considered zone substation diversity and load transfers when planning its zone substation augmentation
- non–network and demand side alternatives were considered as potential alternatives to network augmentation and were provided for in EnergyAustralia's procedures
- EnergyAustralia appeared to be using appropriate methods for the construction and installation of its assets
- the particular types of assets to be used in the capex program during the next regulatory control period are appropriate for the purpose.[1055]

AER considerations

The AER has reviewed EnergyAustralia's capital governance framework and agrees that it contains appropriate controls, checks, accountability, reviews and approval gateways, and is consistent with good industry practice. During meetings with EnergyAustralia planning staff and Wilson Cook, AER staff also had the opportunity to review the application of EnergyAustralia's governance and planning processes in

[1054] Wilson Cook,, volume 2, p. 25.
[1055] Wilson Cook, volume 2, p. 26.

the context of a sample of key projects which are major contributors to the proposed capex program.

The AER notes that EnergyAustralia's *Network investment governance framework* documents the business case approval process supporting EnergyAustralia's internal funding allocation processes.[1056] As part of this process a works program and associated cost estimates are developed each year which are reflected in the annual budget endorsed by the Board. Formal reports are prepared on a monthly basis to monitor progress against the budget and implement corrective actions where necessary.[1057]

The AER also notes that all capital investments go through a process that follows EnergyAustralia's network investment governance principles. The size, type and driver of a project determine the governance process and investment gateways that apply. All projects with a total value greater than $10 million require approval from the EnergyAustralia board based on a comprehensive business case. Individual projects with augmentation components greater than $1 million are subject to demand management investigations, regulatory tests and consultation requirements to meet EnergyAustralia's obligations under the NER.

Overall, the AER is satisfied that EnergyAustralia had observed appropriate processes and procedures in determining and authorising the scope, timing and need for the proposed projects. This accords with the views expressed by Wilson Cook, who have not recommended changes to EnergyAustralia's forecast capex based on their findings in relation to EnergyAustralia's capital governance framework.

At the outset, the AER is satisfied that these processes demonstrate a level of assurance and good practice on the part of EnergyAustralia that supports the observation that its system capex proposal is based on an effective and efficient identification of investment needs. The AER considers this to be relevant in determining whether EnergyAustralia's forecast capex reasonably reflects the capex criteria.

L.5.2 Cost estimation processes

This section examines the methods adopted by EnergyAustralia to estimate costs for identified investment needs in the context of determining whether the AER is satisfied that EnergyAustralia's forecast capex reasonably reflects the capex criteria.

EnergyAustralia proposal

In support of its regulatory proposal EnergyAustralia provided the AER a review conducted by Sinclair Knight Merz Pty Ltd (SKM) of its zone substation cost estimates. As part of its review, SKM produced detailed cost estimates of three substations based on scoping documents provided by EnergyAustralia and high level cost estimates for a further 19 substations.[1058]

[1056] EnergyAustralia, *Regulatory proposal*, attachment 6.3.
[1057] EnergyAustralia, *Regulatory proposal*, attachment 6.3, p. 6.
[1058] EnergyAustralia did not provide its own comparable cost estimate for two of the projects. Consequently SKM was only able to compare the cost estimates for 17 of the projects.

In its detailed review of the three substation projects, SKM's estimates of the civil costs were significantly lower than EnergyAustralia's. After looking in detail at the drivers of the discrepancy, SKM concluded that the civil costs were driven by site and manufacturer specific factors and that high-level review of civil cost was inappropriate. Consequently, SKM did not estimate the civil costs of the remaining 19 substations.

In its review of the remaining 19 substations, SKM noted that the projects were in the preliminary study phase. It found that its substation estimates were all within 20 per cent of EnergyAustralia's and considered them reasonable for feasibility and conceptual purposes.

Consultant review

The AER requested Wilson Cook to develop independent forecasts of unit costs in advance of receiving the DNSPs' proposals. Wilson Cook found that this was not possible as the DNSPs used various methods for cost estimation, relying generally on the reported cost of completed work, internal costing programmes or independent review and not on unit costs of a type that could be compared. It noted that, for the purposes of comparison, unit costs for substation installations were prone to a significant degree of variation, but may be able to be compared:

> …but only in respect of well defined building blocks, and with other DNSPs using similar designs, and excluding site-specific costs.[1059]

With the qualifications noted above Wilson Cook considered EnergyAustralia's proposal, including SKM's review and concluded that, on balance, EnergyAustralia's cost estimates were reasonable for the scope of work concerned.[1060]

AER considerations

The AER has reviewed the cost estimation methods adopted by EnergyAustralia. In the context of determining whether the AER is satisfied that EnergyAustralia's forecast capex reasonably reflects the capex criteria, the NER requires that the AER consider the benchmark capex that would be incurred by an efficient DNSP over the regulatory control period (clause 6.5.7(e)(4)). In its proposal, EnergyAustralia included SKM's review of its substation cost estimates as a benchmark for the purposes of clause 6.5.7(e)(4). Given this, careful consideration was given to SKM's review of EnergyAustralia's substation cost estimates.

The AER notes that SKM reviewed EnergyAustralia's non-civil cost estimates for 22 substations, and considered a cost estimate to be reasonable for 'feasibility and conceptual' purposes if it was within 25 per cent of its own estimate. All of EnergyAustralia's cost estimates were within 20 per cent of SKM's.

EnergyAustralia's cost estimates are compared with those of SKM in figure L.2. The diagonal line represents the line on which EnergyAustralia's cost estimates are equal to SKM's. A point above (below) the line indicates that EnergyAustralia's estimate for that project is greater (lesser) than SKM's. The figure illustrates that, of the non-

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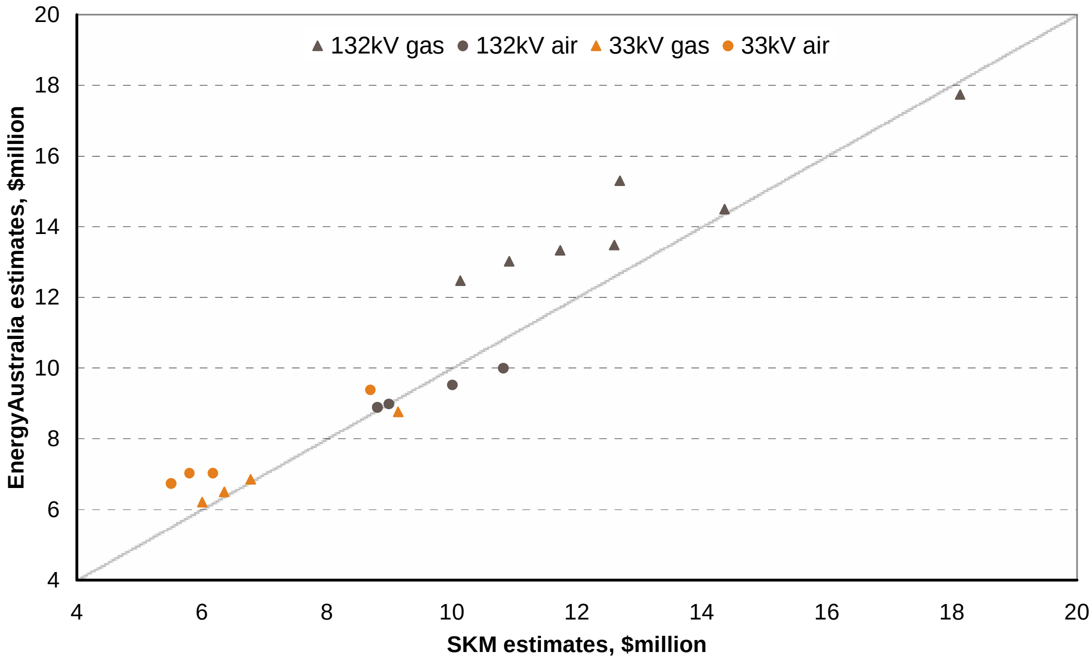
[1059] Wilson Cook, volume 1, p. 10.
[1060] Wilson Cook, volume 2, p. 28.

civil cost estimates for the 20 substations for which both EnergyAustralia and SKM provided estimates, only five of EnergyAustralia's estimates are lower than SKM's. Of the five projects where EnergyAustralia's estimate is lower, the biggest difference between the estimates is 8 per cent. Of those where EnergyAustralia's is higher, the biggest difference is 19 per cent. Five of EnergyAustralia's estimates are at least 15 per cent greater than SKM's estimate. When the totals of all the projects are compared, SKM's estimates are 6 per cent lower than EnergyAustralia's estimates.

Figure L.2: EnergyAustralia's substation cost estimates compared with SKM's estimates



Source: SKM, Attachment 5.14: EA substation cost estimate review, confidential

The AER considers that, on face value, figure L.2 demonstrates that EnergyAustralia's substation cost estimates for 33kV substation projects with air insulated switchgear and 132kV substation projects with gas insulated switchgear are systematically higher than SKM's cost estimates.

In its review of EnergyAustralia's proposed expenditure, Wilson Cook commented on the variations in substation unit cost estimates and the difficulties this creates for comparing EnergyAustralia's estimates to those of an independent source. In particular, Wilson Cook commented on the need to account for site specific costs and to compare like designs. The AER notes that SKM in its review of EnergyAustralia's cost estimates, excluded civil works on the basis they were driven by site and manufacturer specific factors. The AER also notes that EnergyAustralia, in its proposal, included SKM's review of its substation cost estimates as a benchmark for the purposes of clause 6.5.7(e)(4).[1061]

In its review of EnergyAustralia's substation cost estimates SKM noted that its estimates were based on:

[1061] EnergyAustralia, *Regulatory proposal*, p. 97.

- SKM's internal asset valuation database with data sourced from utilities and manufacturers nationally
- a procurement study conducted by SKM conducted in 2005–06 with data sourced from major electricity utilities within Australia
- SKM's price escalation model which produces a power utility specific escalation index
- recent projects of similar characteristics carried out by SKM
- industry specialists within SKM
- Rawlinson's *Australian Construction Handbook,* 2007.[1062]

Having considered Wilson Cook's comments, the fact that EnergyAustralia proposed SKM's cost estimates as a benchmark, and the source of SKM's estimates, the AER considers SKM's cost estimates to be an appropriate benchmark for the purposes of clause 6.5.7(e)(4) of the NER.

In its review, SKM concluded that EnergyAustralia's estimates were 'reasonable for feasibility and conceptual costings' if they were within 25 per cent of its own. The AER considers that, while a plus or minus 25 per cent test may be appropriate for assessing individual projects, this margin should reduce across a sample of projects as the resulting average cost reflects the full range of variability between individual substation costs.

The AER also understands that the substations reviewed by SKM were chosen by EnergyAustralia as being representative of those proposed for development during the next regulatory control period. The sample of substations included both 33kV and 132kV substations with two or three transformers ranging in size from 19MVA to 50MVA, with gas or air insulated switchgear.

Based on the understanding that the substation projects reviewed by SKM were chosen by EnergyAustralia as a representative sample, and that EnergyAustralia's project estimates for 33kV substation projects with air insulated switchgear and 132kV substation projects with gas insulated switchgear were systematically higher than SKM's, the AER is not satisfied that EnergyAustralia's substation cost estimates reasonably reflect the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives.

The AER recognises that there is a degree of uncertainty surrounding the efficient level of costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives. Given this, the AER considers that the non-civil zone substation capex estimate that it is satisfied reasonably reflects the efficient costs that a prudent operator, in the circumstances of EnergyAustralia, would require is the value midway between EnergyAustralia's estimate and SKM's estimate.

[1062] SKM, *EA substation cost estimate review*, attachment 5.14, p. 6.

Consequently, the non-civil substation capex estimate that the AER is satisfied reasonably reflects the efficient costs that a prudent operator, in the circumstances of EnergyAustralia, would require is 3 per cent less than that proposed by EnergyAustralia. These estimates are outlined in table L.3.

Table L.3: Three per cent reduction of non-civil substation costs ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Adjustment	–5.9	– 7.5	– 7.0	– 7.5	– 5.9	–34

L.5.3 Application of input cost escalators

This section examines whether the cost escalators used by EnergyAustralia to develop its capex proposal reflect a realistic expectation of input costs required to meet the capex objectives, in the context of determining whether the AER is satisfied that EnergyAustralia's forecast capex reasonably reflects the capex criteria.

EnergyAustralia proposal

EnergyAustralia has applied real price escalators to its capex forecast based on forecasts for key labour, material and construction costs developed by Competition Economists Group (CEG).[1063] For system capex, by applying weightings (based on price adjustment formulae in EnergyAustralia contracts), these forecasts are used to build up forecasts for key equipment categories, for example transformers, switchgear, substations and cables etc. The key equipment forecasts are then used to create project escalators for a series of typical projects using weightings based on historic expenditure. The project escalators were applied to each of the various plans according to the projects that make up the plan.[1064]

For non–system capex, EnergyAustralia have directly applied the key labour and construction cost escalators to the cost categories that make up non–system capex.[1065]

The AER has calculated an indicative impact of escalation and inflation adjustments to EnergyAustralia's base capex, as illustrated in table L.4.

Table L.4: Impact of EnergyAustralia's cost escalator factors

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Base capex ($ million Dec 06)	1330.7	1322.5	1530.1	1472.4	1401.2	7056.9
Inflation adjustment	78.3	77.8	90.0	86.6	82.4	415.2
Escalation adjustment	173.4	201.5	256.0	269.7	277.5	1178.1
Capex with real cost escalators ($ million 2008–09)	1582.4	1601.8	1876.2	1828.8	1761.1	8650.3

Source: AER estimate based on data from 'Summary capex v2.1.xls', email 28 August 2008.

1063 EnergyAustralia, *Regulatory proposal*, p. 76.
1064 EnergyAustralia, *Estimation and cost indexation process*, April 2008.
1065 EnergyAustralia, email, 11 September 2008

Consultant review

Wilson Cook reviewed a worked example and various spreadsheets showing the calculation and application of the various escalators. Wilson Cook noted that there appeared to be discrepancies in some sheets but that overall it was satisfied with the methodology applied. That is, Wilson Cook considered it reasonable in principle to use inflators for individual inputs weighted to reflect their relevance to particular expenditure categories.[1066]

Wilson Cook was not able to express a view on the reasonableness of the assumptions made regarding future cost movements (in particular the escalation factors determined by CEG). Nor was Wilson Cook able to verify that the method had been applied in the stated manner.

AER considerations

The AER's detailed consideration and conclusions on the NSW DNSPs' proposed input cost escalators, and the methodologies underpinning those escalators, is set out at appendix N to this draft decision.

While the AER is generally accepting of the methodology for deriving input cost escalators, it has made some adjustments and used more recent data to provide what it considers to reasonably reflect a realistic expectation of the input costs required by EnergyAustralia over the next regulatory control period to achieve the capex objectives. The AER has also identified specific issues regarding EnergyAustralia's proposed lag between certain inputs and its equipment costs, the escalation of the cost of wood poles and of non–system capex. These are discussed below.

Application of lag

The methodology applied by EnergyAustralia assumes that price changes in some input cost components will not be reflected immediately in the cost of capex components purchased. Specifically, in developing its key equipment escalators, EnergyAustralia assumed a six month lag for all inputs (including raw materials, labour and producers' margin) to reflect the time it takes these price rises to flow through to key equipment prices.[1067]

The issue of assuming a lag in input prices is addressed at appendix N of this draft decision. In summary, based on observed movements of commodity and producer prices, the AER does not consider it reasonable to assume that there will be a lag between increases in raw material costs and resultant price increases for goods that incorporate those raw materials. Furthermore, as discussed at appendix N, in the absence of any evidence supporting the application of a lag to external labour costs, the AER does not consider it appropriate to lag those labour costs.

The AER notes that EnergyAustralia stated that it had lagged raw materials and external labour cost escalators by six months. The AER reviewed EnergyAustralia's cost escalation model and noted that, in calculating its key equipment cost escalators, EnergyAustralia inadvertently lagged all input cost escalators by 18 months. For

[1066] Wilson Cook, volume 2, p. 28.
[1067] EnergyAustralia, email, 28 August 2008.

example, each key equipment escalator for the 12 months to December 2009 is based on the input cost escalators for the 12 months to June 2008. Consequently, the AER considered that EnergyAustralia, in calculating its key equipment escalators, had incorrectly lagged each input cost escalator by 12 months more than it stated. Given that the 18 months prior to when EnergyAustralia's base costs were set was a period of significant price increases, the impact of this error is significant. In response to the AER, EnergyAustralia advised that correcting this, and other minor errors identified, reduced its proposed capex by $56 million ($2008–09), as outlined in table L.5.

Table L.5: Impact of cost escalation errors ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia's proposed capex	1583.9	1603.3	1877.8	1830.3	1763.2	8658.5
EnergyAustralia's proposed capex with errors corrected	1579.8	1595.4	1859.4	1819.2	1749.2	8602.9
Magnitude of error	4.1	8.0	18.4	11.2	14.0	55.6

Source: EnergyAustralia, email, 19 November 2008.
Note: Totals may not add due to rounding.

In its review of EnergyAustralia's cost escalation model, the AER also noted that EnergyAustralia had lagged, by six months, some general construction and contracted labour costs in calculating its project escalators. The AER notes that these are direct costs of EnergyAustralia and not indirect costs of EnergyAustralia's equipment suppliers, who may take time to pass on increases in input costs to the prices charged to EnergyAustralia. Consequently the AER does not consider it appropriate to lag the construction or contracted labour costs of EnergyAustralia.

Escalation of wood poles

The AER also noted that EnergyAustralia used a different process to calculate its price escalator for poles. EnergyAustralia proposed that the price of wood poles should be escalated by 5 per cent per annum in real terms. EnergyAustralia stated that this figure represented the growth in its pole prices over the period 2002 to 2007 with the impact of the change in forestry licence fees in 2005 removed.[1068] By comparison, ActewAGL and Integral Energy have assumed real annual growth rates of zero per cent, while Country Energy has proposed real price growth of approximately 1 per cent.[1069] To the extent that these DNSPs expect to purchase the same type of wood poles, which seems likely, the AER considers that the shared expectation of no or minimal change in the cost of these assets validates the reasonableness of their expectations.

In considering the justifications put forth by EnergyAustralia for its significantly divergent expectation, the AER is not satisfied that historic trends in prices necessarily provide an accurate forecast of future price movements. While this may be the case, EnergyAustralia has not provided any evidence to demonstrate this claim to

[1068] EnergyAustralia, email, 3 October 2008.
[1069] The AER has not accepted Country Energy's proposed 1 per cent escalation rate, and has applied no real escalation. See appendix K, section K.5.3 for more details.

the AER's satisfaction, including, for example, whether the poles it expects to purchase are of a different type to those that will be purchased and used in the adjacent distribution networks. Accordingly, the AER is not satisfied that the forecast capex associated with EnergyAustralia's proposed pole escalator reasonably reflects the efficient costs required by a prudent operator to achieve the capex objectives. At this time, the AER considers that forecast expenditure for wood poles should not be subject to any real price escalation (that is, they should be escalated by CPI only).

Escalation of non–system capex

The AER notes that in forecasting its capex requirements for the next regulatory control period, EnergyAustralia applied real cost escalators to its forecast non–system capex as outlined in table L.6.

Table L.6 Cost escalators applied by EnergyAustralia to non–system capex

Item	Escalator
IT Labour	CEG (general wages)
IT software/ licences	CEG (general wages)
IT hardware	No nominal escalation[a]
Land	BIS Shrapnel (average)
Buildings	CEG (construction)
Fleet	No nominal escalation[b]
Plant and tools	No real escalation[c]
Furnishings	No real escalation
Other	No real escalation

Source: EnergyAustralia, email, 11 September 2008.
(a) Items that have no nominal escalation applied are not escalated by CPI in nominal terms.
(b) EnergyAustralia noted that not applying an escalator was an oversight. It had intended to escalate fleet expenditure by CPI.
(c) Items that have no real escalation applied are escalated by CPI in nominal terms.

The AER notes that the escalators applied by EnergyAustralia to non–system land, buildings and IT labour are the same as those applied to system land, buildings and labour. The AER considers that this is reasonable as the costs reflected in these escalators do not discriminate between system and non–system expenditures.

However, it is unclear to the AER why IT software and licences should be escalated by the general wages real cost escalator. In the absence of any justification from EnergyAustralia for applying a real labour cost escalator to IT software and licences the AER is not satisfied that this cost category should attract any real cost escalation (that is, they should be escalated by CPI only).

Having considered the real cost escalators proposed by EnergyAustralia for its non–system capex, the AER considers that the escalators outlined in table L.7 should be applied.

Table L.7: AER determined non–system capex real cost escalators

Item	Escalator
IT Labour	AER (general wages)
IT software/ licences	No real escalation
IT hardware	No nominal escalation
Land	AER (land)
Buildings	AER (construction)
Fleet	No real escalation
Plant and tools	No real escalation
Furnishings	No real escalation
Other	No real escalation

Note: AER escalators are outlined in appendix N

As discussed in appendix N, the AER does not consider it appropriate to apply a real escalator for a producer's margin and indirect labour costs in equipment purchases. Consequently, those corresponding components of capex identified in EnergyAustralia's proposal will be escalated at CPI only.

In summary, the AER is not satisfied EnergyAustralia's proposed cost escalation assumptions reasonably reflects the capex criteria, in particular that it is a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives as stated in clause 6.5.7(c)(3). However, the AER will be satisfied these cost escalation assumptions reasonably reflect the capex criteria where EnergyAustralia remodels its cost escalators to:

- remove all cost input lags
- remove real cost escalation of wood poles
- remove real cost escalation of producer margin
- remove real cost escalation of indirect labour in equipment purchases
- remove real cost escalation of IT software and licences
- update escalators for current market conditions
- correct errors.

The AER requested EnergyAustralia remodel its proposed capex program on the basis of these adjustments, which resulted in a $111 million decrease.[1070] For the purposes of this draft decision, the AER considers the remodelled amounts reasonably reflect a

[1070] The AER has not fully verified EnergyAustralia's calculations for the purposes of this draft decision. As such this adjustment is indicative and will be confirmed for the AER's final decision and determination.

realistic expectation of the cost inputs required to achieve the capex objectives. The effect of this remodelling is illustrated in table L.8 below.

The expenditure adjustments arising from these changes are illustrated in table L.8.

Table L.8: AER draft decision–adjustments for real cost escalation ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Cost escalator adjustment	–0.4	–2.8	–21.1	–35.2	–51.1	–110.6

L.5.4 Review by expenditure type

This section examines the scope, timing and costs of EnergyAustralia's proposed expenditure by category (that is, growth, replacement, compliance, reliability and non–system capex) in the context of determining whether the AER is satisfied that EnergyAustralia's forecast capex reasonably reflects the capex criteria.

L.5.4.1 Growth capex

EnergyAustralia proposal

EnergyAustralia has proposed growth capex of $3181 million (2008–09) representing around 37 per cent of the total forecast capex program.

Table L.9: EnergyAustralia's proposed growth capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Growth capex	574	665	673	642	627	3181

Source: EnergyAustralia, RIN template.

Approximately 48 per cent of the proposed growth capex is attributable to the capital works described in EnergyAustralia's area plans. Each of the 28 area plans focuses on a geographic area of the network and incorporates all strategic capex requirements within that area.[1071]

A further 22 per cent of EnergyAustralia's proposed growth capex is attributable to the capital works described in its 11kV network development plan. This plan describes a program of work to achieve compliance with EnergyAustralia's licence conditions and the impact of growth. The plan's scope of work was determined using a network model that calculates network construction costs for a range of compliant configurations.[1072]

Approximately 16 per cent of the proposed growth capex is attributable to the capital works described in EnergyAustralia's customer connection plan. EnergyAustralia retained Evans and Peck to assess its customer connection capex requirements using a statistical model. Customer connection capex is forecast to be greater in the next regulatory control period than the current regulatory control period. EnergyAustralia

[1071] EnergyAustralia, *Regulatory proposal*, p. 60.
[1072] EnergyAustralia, *Regulatory proposal*, attachment 5.7.

stated that the forecast increase is due to increases in the historical expenditure rates and a forecast increase from 15 350 to 17 330 customer connections per annum.[1073]

EnergyAustralia's low voltage capacity plan contributes 9 per cent of the proposed growth capex. The plan sets out a programme of work to rectify overloading on distribution substations and low voltage mains and to maintain loading at a reasonable level. The plan is based on a model developed by Evans and Peck for EnergyAustralia. The model extrapolates known load measurements at specific sites to the population of distribution substations and low voltage mains circuits as a whole. By doing so the model identifies the proportion of sites likely to be in breach of the design load limits by 2013–14.[1074]

The remaining 5 per cent of growth capex is accounted for by property purchases for network assets (1 per cent) and other items (4 per cent). The other items include an allocation of capitalised wages and geographic information system (GIS), demand management, intelligent networks and communications expenditure excluding supervisory control and data acquisition (SCADA).

Submissions

The EMRF noted EnergyAustralia's regulatory proposal 'shows a massive increase in capex, far outstripping demand' and concludes that EnergyAustralia's proposal contains an excess of approximately 50 per cent.[1075] This conclusion is based on a comparison of EnergyAustralia's proposed and actual capex allowance in the context of expected demand growth.

In response to the EMRF's comments, EnergyAustralia referred to the justifications as outlined in its proposal, and noted that only 29 per cent of its proposed capex is related to growth in demand.[1076]

Consultant review

In assessing EnergyAustralia's proposed growth capex Wilson Cook took EnergyAustralia's peak demand forecasts as given. A separate independent review of EnergyAustralia's demand forecasts was undertaken for the AER by McLennan Magasanik Associations (MMA). The outcomes of this review are discussed in detail in chapter 6. In summary, MMA found EnergyAustralia's peak demand forecasts to be reasonable and acceptable for the purposes of assessing its augmentation capex proposal for the next regulatory control period.

EnergyAustralia provided Wilson Cook with copies of all plans and project justifications that were requested for review. Wilson Cook considered that the supporting documentation provided, and the accompanying analysis, was prepared to a high standard and was of a type that Wilson Cook would expect to receive from a well-prepared DNSP.[1077]

[1073] EnergyAustralia, *Regulatory proposal*, attachment 5.6.
[1074] EnergyAustralia, *Regulatory proposal*, attachment 5.10.
[1075] EMRF, p. 16.
[1076] EnergyAustralia, *Response to request for submissions*, p. 3.
[1077] Wilson Cook, volume 2, p. 25.

Wilson Cook was generally satisfied that EnergyAustralia's area plans adequately demonstrated a consistent and appropriate strategy to meet its network development needs. To further test the scope of the investment proposed, Wilson Cook examined a number of area plans in detail. Due to the large number of area plans, Wilson Cook limited its review to a sample of the main projects, examining them from the standpoint of strategy, general timing, reasonableness of approach and consistency with the higher-level plans. The projects reviewed included the:[1078]

- new City North 132/11 kV zone substation
- new 132/11 kV CBD zone substation (Belmore Park) and other works
- eastern CBD tunnel
- new 132/11 kV Bankstown zone substation
- development of the 132/33 kV substation on Kooragang Island.

In each instance Wilson Cook considered the growth capex proposed by EnergyAustralia to be prudent and efficient.

Wilson Cook also reviewed EnergyAustralia's 11 kV network development model, customer connections plan, low voltage capacity plan and property plan. It considered that they were well established documents that set out a prudent and efficient development strategy for the network and its related facilities.[1079]

Wilson Cook considered that the analysis undertaken by EnergyAustralia was comprehensive for the type of assets concerned. Importantly, Wilson Cook considered that EnergyAustralia appropriately determined the need for the proposed growth related projects, gave consideration to the least cost options, considered the optimal timing of the projects and maintained consistency with its policies and broader plans.[1080]

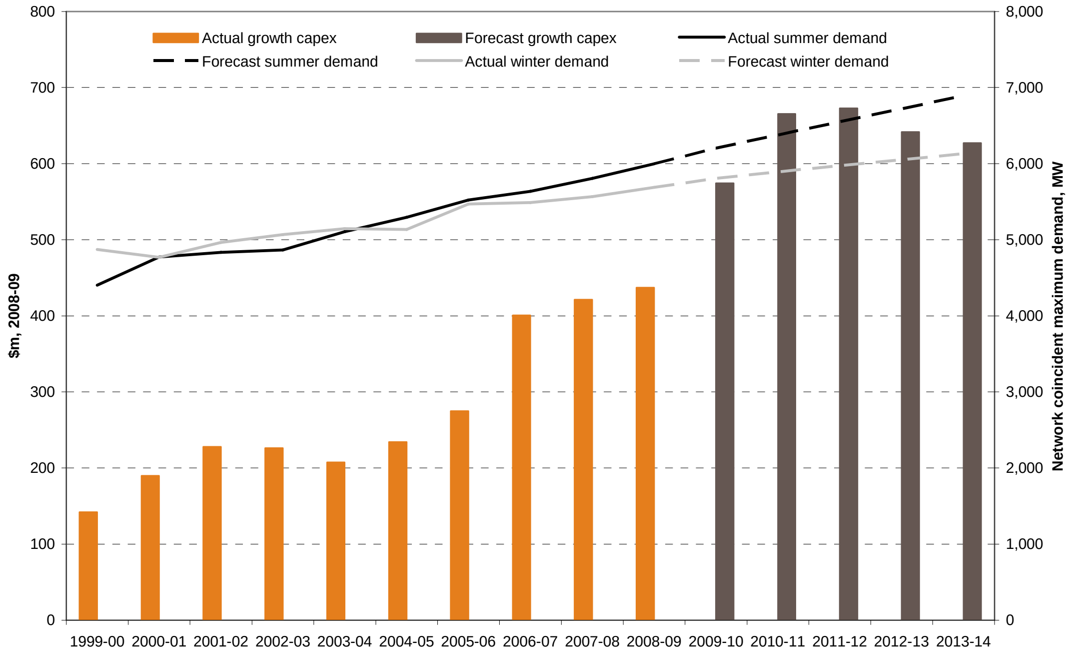
Wilson Cook also noted that it considered that the material provided for review by EnergyAustralia was consistent with that provided for previous assessments.[1081]

AER considerations

The AER has assessed EnergyAustralia's growth related forecast capex. In relation to the data presented by the EMRF and EnergyAustralia's subsequent comments, the AER has undertaken a comparison of changes in EnergyAustralia's growth capex relative to peak demand growth, as illustrated in figure L.3.

[1078] Wilson Cook, volume 2, pp. 19–25.
[1079] Wilson Cook, volume 2, p. 25.
[1080] Wilson Cook, volume 2, p. 25.
[1081] Wilson Cook, volume 2, p. 25.

Figure L.3: EnergyAustralia's growth capex and peak demand



EnergyAustralia's proposed growth capex broadly continues a trend commenced around 2004–05 but with a step increase in 2009–10, which in general appears unrelated to any change in peak demand growth. A significant factor explaining the increase in capex from 2005 is the introduction of new licence conditions, which resulted in the approval of a pass through amount by IPART of approximately $650 million ($2008–09) or around 18 per cent of the capex incurred by EnergyAustralia over the current regulatory control period.[1082]

In explaining the step increase in augmentation expenditure for the next regulatory control period, EnergyAustralia cited the following investment requirements:

- works required to bring zone substations exceeding the design planning criteria from six at the beginning of the period to zero at the end of the period
- increased expenditure on the 11kV system to bring augmentation expenditure back to sustainable levels and to achieve compliance with design planning criteria
- increased spending on distribution substations to achieve compliance with design planning criteria
- increased expenditure on the low voltage system to address present high utilisation and bring augmentation expenditure back to sustainable levels
- increased numbers of urban transmission zone substations to address distribution system capacity issues.[1083]

1082 Derived from EnergyAustralia RIN proformas.

1083 EnergyAustralia, *Regulatory proposal*, Attachment 11.1, pp. 9–10.

The AER has reviewed EnergyAustralia's supporting documentation, including its area plans, 11kV network development model, customer connections plan, low voltage capacity plan and property plan, and engaged in discussions with EnergyAustralia about its growth-related capex. The AER has also considered the advice provided by Wilson Cook and its own assessment of the impact of demand forecasts on the timing of specific projects. Taking into account all of these factors, the AER is satisfied that the proposed growth-related capex reasonably reflects the efficient costs a prudent operator, in the circumstances of EnergyAustralia, would require to achieve the capex objectives and is based on a realistic expectation of demand forecasts and cost inputs, consistent with the capex criteria in clause 6.5.7(c).

L.5.4.2 Replacement capex

EnergyAustralia proposal

EnergyAustralia has proposed replacement capex of $3729 million (2008–09) representing around 43 per cent of the total forecast capex program.

Table L.10: EnergyAustralia's proposed replacement capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Replacement capex	631	639	770	816	873	3729

Source: EnergyAustralia, RIN template

Replacement capex requirements at the transmission and sub–transmission level are coordinated through EnergyAustralia's area plans and its replacement plan. At the distribution level replacement capex is incorporated in EnergyAustralia's replacement plan only. Replacement capex within the area plans accounts for $1634 million or 44 per cent of the proposed replacement capex in the next regulatory control period.

EnergyAustralia stated that the key drivers of the replacement work in the area plans was the need to replace or convert 11kV switchboards incorporating oil-filled switchgear and the need to replace oil and gas-filled transmission and sub–transmission cables due to their poor circuit availability.[1084]

EnergyAustralia has proposed replacing compound–filled switchboards in poor condition. Those switchboards in acceptable condition (and most air-insulated switchboards) are to be converted to use vacuum circuit breakers.

In older and often rural zone substations, 11kV switchgear has been installed outdoors in separate housings. EnergyAustralia stated that condition evaluation has shown these assets to be in a deteriorated state. EnergyAustralia proposed replacing these assets based on risk and condition.[1085]

EnergyAustralia proposed several sub–transmission cable replacements. The replacement of identified gas, oil and Hochstadter single lead cables has been based

[1084] EnergyAustralia, *Regulatory proposal*, p. 61.
[1085] EnergyAustralia, *Regulatory proposal*, p. *Strategic Asset Prioritisation — 11kv switchgear*, p. 9.

on an assessment of maintenance costs, environmental risk and circuit availability utilising fault rates, leakage rates and condition inspection data.

EnergyAustralia's replacement plan is a key component of its general replacement program and covers distribution assets identified for replacement but not included in its area plans. EnergyAustralia forecast $1828 million in replacement capex in its replacement plan, representing 49 per cent of its total proposed replacement capex.

EnergyAustralia's replacement plan describes its approach to the replacement of 148 different asset categories. Key components of the replacement program are outlined in table L.11.

Table L.11: Key components of EnergyAustralia's replacement program

Asset category	Total in 2009–14	Percentage of total program
Distribution substations	344	19
Pole replacements programme	275	15
Low voltage underground mains	219	12
Switchgear (excluding distribution substations)	200	11
High voltage overhead lines (excluding 5kV network)	165	9
CONSAC cables	111	6
Zone transformers	86	5
Other programmes	428	23
Total	**1828**	**100**

Source: EnergyAustralia, *Replacement plan 2009–14*.

Submissions

EnergyAustralia noted that sections of its network are at or near the end of their lives. It stated that when this occurs equipment becomes subject to random failure modes which cannot be addressed through inspection and corrective maintenance. Failure to replace the aged equipment would result in increasing levels of functional failures, with associated safety, reliability and cost impacts.[1086]

EnergyAustralia stated that it had assessed the risks and consequences of deferring asset replacement. The primary risk and consequences relate to the limited and narrow windows of time available to undertake maintenance, repair and replacement as well as limited opportunities to make new connections to the existing network. EnergyAustralia stated that not investing during these available windows would result in:

- network reliability being compromised
- future investment options being limited

[1086] EnergyAustralia, *Response to request for submissions*, p. 5.

- an overlay sub–transmission network being required to facilitate future works, which would be at significant cost to EnergyAustralia and customers.[1087]

No submissions were received from other interested stakeholders that referred directly to EnergyAustralia's proposed replacement capex.

Consultant review

In general, Wilson Cook considered that EnergyAustralia had demonstrated a suitable condition and risk-based approach to identifying replacement needs.[1088] Wilson Cook undertook a detailed review of a number of particular projects in the area plans, including:

- Kogarah 132/11kV zone substation
- Lake Munmorah 132/11kV zone substation
- new Rose Bay 132/11kV zone substation
- 132kV feeders 91L and 91M
- 132kV feeder 900.

In each instance Wilson Cook considered the replacement capex proposed by EnergyAustralia to be prudent and efficient.

Wilson Cook also reviewed in detail a number of the sub-programs in EnergyAustralia's replacement plan, including the replacement of:

- distribution substations
- poles
- low voltage underground mains
- low voltage CONSAC cables
- other zone and sub–transmission substation switchgear
- high voltage overhead lines
- zone transformers
- low voltage services
- ducts
- meters

[1087] EnergyAustralia, *Response to request for submissions*, p. 6.
[1088] Wilson Cook, volume 2, p. 31.

- low voltage overhead mains
- high voltage underground mains.

In each instance Wilson Cook considered the replacement capex proposed by EnergyAustralia to be prudent and efficient.

In reviewing EnergyAustralia's proposed replacement capex Wilson Cook was satisfied that EnergyAustralia had followed reasonable policies and procedures that included the identification of need and the determination of least-cost solutions.

Wilson Cook considered that EnergyAustralia's proposed replacement capex (and its implicit timing) appeared reasonable. It considered that the consistent and rising trend in replacement expenditure was matched to EnergyAustralia's understanding of the age and condition of its network and the ability of EnergyAustralia to resource the substantial scope of works. Furthermore Wilson Cook considered that the scope of replacement work proposed was generally consistent with the reported fault rates and trends observed.[1089]

In summary, Wilson Cook was satisfied that the scope of replacement work proposed by EnergyAustralia was prudent and efficient.

AER considerations

The AER recognises that EnergyAustralia's network is the oldest in the country and that it includes a notable quantity of assets installed before 1960 and a large number of assets installed between 1960 and 1985. The AER also recognises that, even though prudent management and condition monitoring can enable many assets to be kept in service beyond their design life, a high proportion of aged assets can present an increased risk to the network.

In reviewing EnergyAustralia's replacement capex proposal the AER has given consideration to EnergyAustralia's network performance in terms of fault rates. In particular the AER notes that EnergyAustralia's underground circuit fault rate, when all fault classifications are considered, compares well to New Zealand, UK and other NSW DNSPs but the performance of its overhead circuits is worse than reported in the New Zealand and UK.[1090] When only faults attributable to condition are reviewed, EnergyAustralia's performance data shows a rising fault trend for its underground mains and a generally falling fault trend for overhead mains. Broadly, these fault rates and trends appear consistent with the replacement capex proposed by EnergyAustralia.[1091]

The AER notes that some of EnergyAustralia's assets identified for replacement are highly utilised and that replacement is only possible in the autumn and spring low-load months, requiring the replacement program to be undertaken over a number of years.

[1089] Wilson Cook, volume 2, p. 36.
[1090] Wilson Cook, volume 2, p. 6.
[1091] Wilson Cook, volume 2, p. 6.

The AER also notes that the reliability data provided by EnergyAustralia shows poor availability for a number of oil and gas-filled cables due to ongoing leaks. The AER recognises that these leaks not only reduce network performance but also pose significant environmental risks.

The AER has also reviewed the expenditure associated with the proposed replacement program. The AER notes that EnergyAustralia's replacement capex estimates have been derived from EnergyAustralia's historic costs and that the majority of capex is related to the procurement of materials and contract services that have been obtained competitively.

Consequently, having reviewed the investment plans provided by EnergyAustralia, including its area plans and replacement plan, and having considered the advice provided by Wilson Cook, the AER is satisfied that the proposed replacement forecast capex reasonably reflects the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives..

L.5.4.3 Statutory obligations, environmental and safety capex

EnergyAustralia proposal

EnergyAustralia proposed $450 million ($2008–09) of expenditure in this category, which accounts for approximately 5 per cent of its total proposed capex program.[1092] This compares to an estimated $196 million ($2008–09) in the current regulatory control period. This expenditure reflects EnergyAustralia's expected requirements to comply with its environmental, occupational health and safety and security requirements, and is outlined in table L.12.

Table L.12: Forecast compliance capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Distribution compliance capex	53.2	50.8	87.4	94.0	68.1	353.6
Transmission compliance capex	14.7	26.1	22.5	18.6	14.6	96.5
Total compliance capex	67.9	76.9	109.9	112.7	82.7	450.1

Source: EnergyAustralia, *Regulatory proposal*, RIN template.
Note: Totals may not add due to rounding

A significant component of EnergyAustralia's proposed compliance capex is incorporated in its duty of care plan. The duty of care plan outlines EnergyAustralia's obligations in relation to:[1093]

- **Safety**: both public and workplace safety, including fire prevention and risk mitigation strategies, and asbestos management and removal strategies. Major programmes in this category include the correction of 33 kV bus bar heights and protection for brick-walled outdoor enclosure substations.

[1092] EnergyAustralia, *Regulatory proposal*, RIN template.
[1093] EnergyAustralia, *Regulatory proposal*, 5.5.

- **Environmental**: including obligations in respect of waste disposal, pollution, contamination of land, remediation and environmentally hazardous chemicals. The major expenditure in this category relates to EnergyAustralia's oil containment programmes.

- **Infrastructure risk**: asset security and compliance risks relevant to EnergyAustralia's network assets. Major projects in this category include the installation of electronic security and the replication of the system control centre in Sydney at a secure location.

The duty of care plan outlines the steps EnergyAustralia is taking, or plans to take, to manage these risks. It also identifies specific projects in each of the three categories, along with the proposed mitigation approach and the estimated costs involved in managing the relevant risks.[1094]

Compliance expenditure for EnergyAustralia's transmission network is incorporated in its transmission area plans and accounts for approximately 37 per cent of the expenditure in this category. Major identifiable projects under the area plans include the replacement of some transformers with gas-insulated units to reduce the risk of fire and the correction of 33kV bus bar heights at various locations.[1095]

Wilson Cook review

Wilson Cook considered the compliance capex proposed by EnergyAustralia within its area plans and duty of care plan and accepted the proposed expenditure as reasonable.[1096]

AER considerations

The AER has reviewed EnergyAustralia's forecast environmental, safety and statutory compliance expenditure. It notes the proposed forecast capex is more than double that in the current regulatory control period. Significant contributors to this increase include:

- the redesign and remediation of pits and ducts in the Sydney CBD to comply with confined spaces requirements in occupational health and safety regulations

- the replacement of 33kV busbars which do not meet mandatory minimum busbar heights

- the protection of outdoor substations with brick wall enclosures to prevent unauthorised entry and electrocution

- the replacement of asbestos roofs in distribution substations to meet requirements in occupational health and safety regulations

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[1094] EnergyAustralia, *Regulatory proposal*, attachment 5.5.
[1095] EnergyAustralia, *Regulatory proposal*, attachment 5.5.
[1096] Wilson Cook, volume 2, p. 39.

- the implementation or upgrade of oil containment systems at substation sites to comply with mandatory environmental obligations

- the installation of electronic security to prevent or impede unauthorised access to zone and sub–transmission substations.

Having reviewed the proposed compliance expenditure the AER is satisfied that the proposed capital investment is required to comply with EnergyAustralia's various regulatory obligations and to maintain the security of the distribution system and is thus consistent with capex objectives 6.5.7(a)(2) and 6.5.7(a)(4).

Based on its review of these factors, and the advice provided by Wilson Cook, the AER is satisfied that the compliance capex proposed reasonably reflects the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives.

L.5.4.4 Reliability and quality improvement capex

In December 2007, the NSW Minister for Energy updated the design, planning and reliability licence conditions for the NSW DNSPs. These licence conditions include mandatory minimum average annual performance standards for four feeder types (CBD, urban, short rural and long rural). The performance standards include both duration (system average interruption duration index, or SAIDI) and frequency (system average interruption frequency index, or SAIFI) measures. The performance standards in the licence conditions reflect an improved level of performance each year through 2010–11.[1097]

EnergyAustralia proposal

EnergyAustralia comments in its reliability investment plan that it must target an average level of performance superior to the performance standard in the licence conditions because failing to meet the standard in the licence conditions in any one year would be a breach of those licence conditions.[1098]

Consequently EnergyAustralia has developed 'feeder category management targets'. These are the levels of performance that EnergyAustralia will aim for to ensure an acceptably low risk of non-compliance. In determining these 'feeder category management targets', EnergyAustralia considered that a 5 per cent chance of non-compliance each year was a reasonable probability of non-compliance.[1099]

EnergyAustralia then forecast the reliability of its distribution system under the assumption that all of its proposed capex is completed. Forecast average feeder performance either met, or was close to, the feeder category management target for all feeder types, except long rural which was significantly short of the target.

[1097] Ian Macdonald, *Reliability and Performance Licence Conditions for Distribution Network Service Providers*, December 2007.
[1098] EnergyAustralia, *Regulatory proposal*, attachment 4.9, p. 14.
[1099] EnergyAustralia, *Regulatory proposal*, attachment 4.9, p. 15.

Consequently EnergyAustralia has proposed that $20 million (2008–09) be spent on works to improve the performance of one of its long rural feeders.[1100]

In addition, EnergyAustralia anticipates that long rural performance will be further improved through its distribution monitoring and control program. This program, among other things, aims to restore the system quicker after an outage event through the installation of devices such as reclosers, supervisory control and data acquisition (SCADA) controlled switches and SCADA monitored fault indication devises. EnergyAustralia has proposed $9.6 million for this program in the next regulatory control period.[1101]

Consultant review

Wilson Cook assessed EnergyAustralia's proposed approach to meeting its service quality and reliability requirements. In undertaking this assessment, Wilson Cook did not:[1102]

> … express an opinion on the appropriateness of setting a target that is more onerous than the required level in average since it appears to be a matter of interpretation of the licence conditions. However, we note the matter for consideration by the AER as potentially it gives rise to different levels of expenditure by the DNSPs in circumstances that otherwise would be the same.

While not assessing the target themselves, Wilson Cook concluded that the reliability improvement capex proposed by EnergyAustralia was reasonable when based on the method of compliance chosen.[1103]

AER considerations

The AER has reviewed the forecast capex proposed by EnergyAustralia to meet the SAIDI and SAIFI performance standards required by its licence conditions. It notes that, over the current regulatory period, EnergyAustralia has met those licence conditions for all feeder types with the exception of its long rural feeders in 2006–07 (table L.13).

The AER also notes that EnergyAustralia has elected to target more stringent 'feeder category management targets' that equate to a 95 per cent probability of meeting the target. The AER notes that were EnergyAustralia to work to achieve the licence condition mandatory performance levels on average then there were would be a significant probability that EnergyAustralia would breach its licence conditions in the next regulatory control period. Consequently the AER considers it appropriate that EnergyAustralia target a superior level of performance than that required by the licence condition.

The AER recognises that, conceptually, EnergyAustralia is targeting a level of performance less that that required by its licence conditions. A strict interpretation of EnergyAustralia's licence conditions would require it to target a level of performance

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1100 EnergyAustralia, *Regulatory proposal*, attachment 4.9, p. 20.
1101 EnergyAustralia, *Regulatory proposal*, attachment 4.9, pp. 18–19.
1102 Wilson Cook, volume 2, p. 39.
1103 Wilson Cook, volume 2, p. 39.

corresponding to a 100 per cent probability of compliance, rather than 95 per cent. However, the AER recognises that, depending on the circumstances of the DNSP, it may not be possible to set a performance target corresponding to a 100 per cent probability of compliance. That is, there may be some chance, however small, that actual performance on average will not meet the performance standard set in the licence conditions. Consequently the AER considers it reasonable for EnergyAustralia to target a level of performance with a probability of compliance of less than 100 per cent.

The AER notes that EnergyAustralia proposes to spend $29.6 million ($2008–09) as part of its reliability investment plan to meet its average feeder performance licence conditions. While EnergyAustralia could avoid this expenditure if it targeted a lower probability of compliance, this would also raise the likelihood of it breaching its licence conditions. Table L.14 outlines EnergyAustralia's projected average feeder performance (assuming the reliability investment plan is undertaken), its 'feeder category management targets', and its average feeder performance licence conditions in 2010–11.

The AER notes that EnergyAustralia's forecast long rural SAIDI performance in 2010–11 is forecast to not only fail to meet EnergyAustralia's feeder category management target but also the mandatory level of performance required by the licence conditions.

The AER also notes that forecast average performance on both short rural and urban feeders is close to EnergyAustralia's feeder category management targets. If EnergyAustralia were to target a lower probability of non-compliance performance their feeder category management targets would be lower and forecast performance on these feeder types would likely not meet those targets. Thus targeting a lower probability of non-compliance would likely require capex on EnergyAustralia's urban and short rural feeders as well as its long rural feeders. This demonstrates the fact that the marginal cost of reducing the probability of non-compliance will increase as the target probability of non-compliance is reduced.

Table L.13: EnergyAustralia's SAIDI and SAIFI performance

	03–04	04–05	05–06	06–07	07–08	08–09	09–10	From 10–11
SAIDI—Minutes per customer								
CBD								
Actual	105.96	9.34	13.00	13.04	-	-	-	-
Target	n/a	n/a	60	57	54	51	48	45
Urban feeder								
Actual	75.23	76.09	68.5	77.56	-	-	-	-
Target	n/a	n/a	90	88	86	84	82	80
Short rural								
Actual	351.22	245.49	336.5	290	-	-	-	-
Target	n/a	n/a	400	380	360	340	320	300
Long rural								
Actual	818.09	952.52	342.2	1093.47	-	-	-	-
Target	n/a	n/a	900	860	820	780	740	700
SAIFI—Number per customer								
CBD								
Actual	0.17	0.09	0.20	0.17	-	-	-	-
Target	n/a	n/a	0.35	0.34	0.33	0.32	0.31	0.30
Urban feeder								
Actual	1.07	1.07	0.96	0.96	-	-	-	-
Target	n/a	n/a	1.30	1.28	1.26	1.24	1.22	1.20
Short rural								
Actual	3.75	2.73	3.32	2.76	-	-	-	-
Target	n/a	n/a	4.40	4.20	3.90	3.70	3.40	3.20
Long rural								
Actual	8.14	6.74	3.30	5.64	-	-	-	-
Target	n/a	n/a	8.50	8.00	7.50	7.00	6.50	6.00

Source: EnergyAustralia, *Network performance report 2006–07*, pp. 24–25; Ian Macdonald, *Design, Reliability and performance licence conditions for distribution network service providers*, December 2007.

Table L.14: EnergyAustralia projected reliability performance in 2010–11

	Projected reliability performance	'Feeder category management target'	Licence condition
CBD SAIDI	15	14	45
CBD SAIFI	0.15	0.15	0.3
Urban SAIDI	71.3	70	80
Urban SAIFI	1.02	1.06	1.2
Short rural SAIDI	238.7	247	300
Short rural SAIFI	2.80	2.72	3.2
Long rural SAIDI	729.7	457	700
Long rural SAIFI	5.75	4.38	6

Sources: EnergyAustralia, *Reliability investment plan development*, April 2008.
Ian Macdonald, *Design, Reliability and performance licence conditions for distribution network service providers,* December 2007.
Notes: SAIDI is measured in minutes per customer.
SAIFI is measured in number per customer.

The AER considers that EnergyAustralia has appropriately recognised that it is not possible to target a 100 per cent probability of compliance. The AER also considers that EnergyAustralia has proposed a target probability of compliance that appropriately balances the probability of non-compliance with the cost of targeting a lower probability of non-compliance.

The AER has also reviewed the expenditure associated with the proposed reliability program. The AER notes that EnergyAustralia's reliability capex estimates have been derived from EnergyAustralia's historic costs and that the majority of capex is related to the procurement of materials and contract services that have been obtained competitively.

Consequently, on consideration of EnergyAustralia's *Reliability investment plan*, the licence conditions and the advice provided by Wilson Cook, the AER considers that the capex proposed by EnergyAustralia to meet its minimum average feeder performance licence requirements reasonably reflects the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives.

L.5.4.5 Non–system capex

EnergyAustralia proposal

EnergyAustralia's proposed non–system capex includes expenditure on non–system IT, plant, equipment, motor vehicles, land, buildings and other non–system assets and is outlined in table L.15. Non–system capex contributes 7 per cent of EnergyAustralia's total forecast capex.

Table L.15: EnergyAustralia's proposed non–system capex ($m, 2008–09)

Year	2009–10	2010–11	2011–12	2012–13	2013–14	Total
IT systems	82.4	49.5	37.0	38.6	32.0	239.5
Furniture, fittings, plant and equipment	5.8	5.7	5.6	5.6	5.7	28.4
Motor Vehicles	25.7	23.1	18.7	16.7	16.7	101.0
Buildings	68.0	37.8	49.5	26.0	28.7	210.1
Land	40.9	0.0	0.0	0.0	0.0	40.9
Total	222.9	116.2	110.9	86.9	83.1	620.0

Source: EnergyAustralia, RIN template 2.2.1.

EnergyAustralia has proposed non–system capex of $620 million ($2008–09) for the next regulatory control period, compared with $534 million ($2008–09) in the current regulatory control period, an increase of 16 per cent. Non–system capex represents 7 per cent of EnergyAustralia's total proposed capex for the next regulatory control period. Proposed non–system capex in the next regulatory control period for IT systems and buildings is greater than expenditure in the current regulatory control period. Proposed non–system capex for motor vehicles and land is forecast to be lower. Proposed non–system capex for furniture, fittings, plant and equipment is projected to be similar to that in the current regulatory control period.[1104]

Consultant review

Wilson Cook assessed EnergyAustralia's non–system capex against the other NSW DNSPs' forecasts and the regulatory allowances of Ergon and Energex from the 2005 Queensland network determination made by the Queensland Competition Authority. These comparisons were made on a 'cost-per-size' basis which Wilson Cook considers takes into account the main parameters which drive non–system capex. These comparisons revealed that EnergyAustralia's proposed non–system capex was in the middle of the range of the group analysed. Wilson Cook considered that the benchmarking indicated that from a top-down perspective that EnergyAustralia's overall level of non–system capex was reasonable.[1105]

To support its top-down review, Wilson Cook also undertook a bottom-up review of a number of specific expenditure categories and projects within EnergyAustralia's proposed non–system capex. As part of this, Wilson Cook reviewed a number of supporting documents provided by EnergyAustralia for specific IT projects. It concluded that EnergyAustralia's proposed IT non–system capex was similar to other network businesses. Wilson Cook considered the number of major projects over the next regulatory control period was high but that this reflected some previous under-investment. Wilson Cook noted, however, that improvements could be made in

1104 EnergyAustralia, RIN template 2.2.1.
1105 Wilson Cook, volume 2, p. 42.

identifying the business efficiency improvements to be expected from the investments.[1106]

Wilson Cook also benchmarked EnergyAustralia's proposed IT capex on a cost-per-customer and cost-per-size basis. Wilson Cook concluded that EnergyAustralia's proposed IT capex was reasonable but noted that the proposed investments should result in improved business efficiencies and operational cost savings.[1107]

It addition to its review of proposed IT capex, Wilson Cook also reviewed EnergyAustralia's fleet management policies and capex forecasting processes. Wilson Cook noted that EnergyAustralia's forecast fleet capex was comprised of mainly replacement expenditure on its existing fleet in accordance with its documented vehicle replacement policies. The fleet capex forecast also included increases in the size of the fleet to support the proposed capital investment and maintenance programs. Wilson Cook concluded that EnergyAustralia's fleet policies and processes were appropriate.[1108]

Wilson Cook also reviewed EnergyAustralia's corporate property strategy. Wilson Cook noted that EnergyAustralia's forecast property expenditure was based on a strategic review of non–system-related property holdings. The review was driven by an increase in staff numbers from 3976 in 2004 to over 5000. Wilson Cook considered the review undertaken by EnergyAustralia and concluded that a robust process had been followed and that the proposed expenditure was reasonable.[1109]

Consideration was also given to EnergyAustralia's proposed expenditure on furniture, fittings, plant and equipment. Wilson Cook noted that EnergyAustralia's proposed capex was slightly less than that in the current regulatory control period. Based on the historical trend Wilson Cook considered the proposed capex reasonable.[1110]

Based on both the top-down and bottom-up review conducted, Wilson Cook concluded that no adjustment of the non–system capex proposed by EnergyAustralia was needed.[1111]

AER considerations

The AER has reviewed EnergyAustralia's fleet capital investment forecasting process, corporate property strategy and non–system IT capex proposal and notes that EnergyAustralia's proposed non–system capex for IT systems and buildings is greater than expenditure in the current regulatory control period.

The AER has reviewed the benchmark analysis of EnergyAustralia's proposed IT capex and notes that the proposed IT capex is slightly above that of comparable distributors. The AER notes that EnergyAustralia's IT investment in the current regulatory control period was less than the depreciation charge on its IT assets. Consequently expenditure in the current regulatory control period has not reflected

1106 Wilson Cook, volume 2, p. 44.
1107 Wilson Cook, volume 2, p. 44.
1108 Wilson Cook, volume 2, p. 45.
1109 Wilson Cook, volume 2, p. 45.
1110 Wilson Cook, volume 2, p. 45.
1111 Wilson Cook, volume 2, p. 45.

EnergyAustralia's renewal requirements. Given this under expenditure, the AER is satisfied that the proposed non–system IT capex reasonably reflects the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives

The AER notes that EnergyAustralia's corporate property strategy indicated that an increase in staff numbers was a significant driver of the proposed increase in non–system building expenditure. Having reviewed the corporate property strategy the AER agrees with Wilson Cook that EnergyAustralia followed a robust process and that the proposed expenditure was reasonable.

The AER also notes Wilson Cook's top down assessment of EnergyAustralia's proposed non–system capex which found the proposed capex to be in the middle of the range of the group analysed.

Having considered these factors, and the advice provided by Wilson Cook, the AER is satisfied that the proposed non–system capex reasonably reflects the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives.

L.5.5 'Black spot' reliability program

EnergyAustralia has included as part of its reliability investment plan a 'black spot' reliability program. This program is designed to improve performance for individual customers on the worst served segments of the network.

EnergyAustralia proposal

In its regulatory proposal EnergyAustralia notes that the NSW DRP licence conditions do not focus on the reliability experienced by individual customers. Schedules 2 and 3 of the licence conditions address average feeder category and individual feeder level performance respectively. However, for some feeder categories, particularly those with significant segmentation through the use of reclosers and fuses, some customers further away from the zone substation can experience a level of performance significantly below the feeder average.[1112]

Under the customer service standards in schedule five of the licence conditions, customers can seek a compensation payment from EnergyAustralia for very poor performance. However, EnergyAustralia argued that these standards are not useable as a 'proactive minimum individual customer service standard' primarily because of the duration threshold in the standards. Consequently EnergyAustralia developed the 'black spot' reliability program to address this perceived 'individual customer gap' in the licence conditions.[1113]

The 'black spot' reliability program is based on reliability thresholds (for outage frequency and outage duration) determined by EnergyAustralia from analysis of past customer level reliability data. EnergyAustralia identified those customers who

[1112] EnergyAustralia, *Regulatory proposal*, p. 65.
[1113] EnergyAustralia, *Regulatory proposal*, Attachment 4.9, p. 22.

repeatedly exceeded the thresholds and whose performance was unlikely to be addressed by its other reliability projects.[1114]

To improve the network performance experienced by these customers EnergyAustralia proposed a program of work on individual distributions centres or low voltage distributors as well as some work on small areas at the tail of 11kV feeders. The proposed capex for these works is outlined in table L.16.

Table L.16: EnergyAustralia's proposed 'black spot' reliability program capex ($m, real 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
'Black spot' reliability capex	3.1	3.1	3.2	3.3	3.3	16.1

Source: EnergyAustralia, *Regulatory proposal*, *Reliability investment plan development,* p. 27.

Consultant review

Wilson Cook did not specifically address EnergyAustralia's 'black spot' reliability program. However, it did address the program as part of its assessment of reliability improvement capex. In assessing EnergyAustralia's reliability improvement capex, Wilson Cook stated that it considered EnergyAustralia's proposed reliability improvement capex to be 'reasonable when based on the method of compliance chosen by EnergyAustralia'.[1115]

AER considerations

The AER is required to determine whether EnergyAustralia's proposed forecast capex reasonably reflects the capex criteria of the transitional chapter 6 rules. In turn, the capex criteria are set out in the context of that required to achieve the capex objectives, being to:

1. meet or manage the expected demand for standard control services over the regulatory control period

2. comply with all applicable regulatory obligations or requirements associated with the provision of standard control services

3. maintain the quality, reliability and security of supply of standard control services

4. maintain the reliability, safety and security of the distribution system through the supply of standard control services.

The AER notes that EnergyAustralia stated in it regulatory proposal that, through its 'black spot' program, it is seeking to fill 'the individual customer gap in the DRP licence conditions'.[1116] Consequently the objective of the 'black spot' reliability program is not to comply with an applicable regulatory obligation or requirement. Nor

[1114] EnergyAustralia, *Regulatory proposal*, Attachment 4.9, p. 22.
[1115] Wilson Cook, volume 2, pp. 38–39.
[1116] EnergyAustralia, *Regulatory proposal*, p. 65.

is the program required to meet or manage the expected demand for standard control services.

The capex objectives in clauses 6.5.7(a)(3) and 6.5.7(a)(4) of the transitional chapter 6 rules refer to maintaining the quality, reliability, safety and security of standard control services and the distribution system. EnergyAustralia has provided no evidence that the 'black spot' reliability program is required to meet either of these objectives. Rather, EnergyAustralia argues that the 'black spot' reliability program will be used to 'initiate appropriate reliability improvements'.[1117] The AER considers that EnergyAustralia has not demonstrated that the 'black spot' reliability program is required to maintain quality, reliability and security of supply of standard control services or the reliability, safety and security of the distribution system.

Consequently, the AER is not satisfied that the objective of the 'black spot' reliability program, as described by EnergyAustralia, is consistent with the capex objectives and accordingly is not satisfied that the associated costs reasonably reflect the capex criteria, being the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives.

The AER notes that, although it does not consider the objective of the 'black spot' reliability program to be consistent with the capex objectives, it does not express a view on the merits of improving the reliability of service to the worst served customers on EnergyAustralia's network. Nor does the AER express a view on whether the proposed 'black spot' reliability program should proceed. The AER notes that the 'black spot' reliability program represents a small proportion of EnergyAustralia's proposed capex and that, under the ex ante incentive framework, EnergyAustralia may proceed with the program if it considers it appropriate to do so.

L.5.6 Replacement of feeder cables 908 and 909

In the ACCC's 2005 revenue determination for EnergyAustralia, the ACCC accepted that feeder cables 908 and 909 would need to be replaced during the current regulatory control period but considered the forecast costs of the project to be uncertain.[1118] Consequently, the ACCC classified this as a contingent project and included $37 million ($2003–04) as an indicative capex allowance being the minimum amount it considered the project would cost. The ACCC anticipated that EnergyAustralia would make a contingent project application to amend the ACCC determination to include additional revenue as soon as it had an accurate forecast of the cost of the project.[1119]

EnergyAustralia lodged a contingent project application with the AER on 9 May 2008 to replace feeder cables 908 and 909. The AER assessed EnergyAustralia's application and was satisfied, subjected to amendment, that the proposed expenditure

[1117] EnergyAustralia, *Regulatory proposal*, p. 65.
[1118] ACCC, *NSW and ACT transmission network revenue cap EnergyAustralia 2004–05 to 2008–09: Decision*, April 2005, p. 67–68.
[1119] ACCC, *NSW and ACT transmission network revenue cap EnergyAustralia*, p. 67–68.

reflected prudent and efficient costs and a realistic expectation of demand forecasts and cost inputs.[1120]

The AER amended EnergyAustralia's proposed expenditure on the basis that it considered that several items were allocated a higher than appropriate contingency allowance. Consequently the AER determined that a total forecast capex of $134 million ($2003–04) for this contingent project to be appropriate. This was $8.9 million less than the total capex requested by EnergyAustralia.

EnergyAustralia informed the AER in its contingent project application that work would commence on the project in July 2008 and be completed by June 2010. Consequently, the capex for this contingent project will be incurred in both the current and the next regulatory control periods.

EnergyAustralia proposal

EnergyAustralia noted in its regulatory proposal that it would spend $114 million ($2008–09) on feeders 245 and 246 which replace feeders 908 and 909.[1121] This figure includes only the replacement cable project and does not include the cost of the Bunnerong connections, which were included as part of the contingent project. The total incurred and proposed capex for the contingent project are outlined in table L.17.

Table L.17: Incurred and proposed capex for the replacement of feeders 908 and 909 ($m, 2008–09)

	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	Total
EnergyAustralia proposal	0.4	0.9	1.2	3.8	39.3	96.5	17.9	160.0

Source: EnergyAustralia, email 7 October 2008.

Consultant review

Wilson Cook reviewed the replacement of feeders 908 and 909 and noted that these feeders have poor availability, affecting the security of supply to Bunnerong sub–transmission substation. Wilson Cook considered that these feeders, the only remaining 132kV gas-filled cables on EnergyAustralia's network, were obsolete, had unacceptable outage rates and lacked adequate spares. After assessing the options analysis conducted by EnergyAustralia, Wilson Cook was 'satisfied that the option chosen represents the best solution'.[1122]

AER considerations

In determining the allowance for the remaining forecast capex to be incurred during the next regulatory control period for this contingent project, the AER has applied clause 6A.6.7 of the NER as required by the relevant transitional provision for EnergyAustralia (clause 11.6.19(g) of the NER).

[1120] AER, *Contingent project application: EnergyAustralia Replacement of feeder cables 908 and 909: Decision*, July 2008.
[1121] EnergyAustralia, *Regulatory proposal*, p. 100.
[1122] Wilson Cook, volume 2, p. 22.

According to clause 6A.6.7(h), the capex that EnergyAustralia proposed in the next regulatory control period for the replacement of feeder cables 908 and 909 should be equal to the difference between the total capex determined by the AER for the contingent project and the total capex incurred by EnergyAustralia in the current regulatory control period.

EnergyAustralia proposed a total capex for the replacement of feeders 908 and 909 of $160 million ($2008–09), which is $7.6 million ($2008–09) greater than the $152 million ($2008–09) allowed in the AER's contingent project decision. However, the AER notes that EnergyAustralia submitted its regulatory proposal on 2 June 2008, prior to the publication of the AER's contingent project decision in July 2008.

In applying clause 6A.6.7 and the AER's contingent project decision, the AER does not agree with EnergyAustralia's proposed $114 million in the next regulatory control period. Instead the AER considers the capex allowance for the replacement of feeders 908 and 909 for the next regulatory control period should be $107 million ($2008–09). This is the difference between the total capex determined by the AER for the contingent project, $152 million ($2008–09), and the total capex incurred in the current period by EnergyAustralia, $46 million ($2008–09).

The AER notes that EnergyAustralia's regulatory proposal includes some capex in 2010–11, which represents a deferral of expenditure from that allowed in the AER's contingent project decision. In the absence of evidence to the contrary, the AER considers this deferral prudent and efficient.

To determine the efficient allocation of capex between 2009–10 and 2010–11, the AER considered adjusting EnergyAustralia proposed capex for either 2009–10 or 2010–11, or adjusting capex for both years on a pro-rata basis. The AER considered that of these options, the pro-rata option appeared most reasonable and the adjustments to EnergyAustralia's proposed capex in table L.18 were calculated on that basis.

Table L.18: Incurred and proposed capex for the replacement of feeders 908 and 909 ($m, 2008–09)

	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	Total
EnergyAustralia proposal	0.4	0.9	1.2	3.8	39.3	96.5	17.9	160.0
AER contingent project decision	0.4	0.9	0.9	6.9	43.6	99.8	0	152.4
AER draft decision	0.4	0.9	1.2	3.8	39.3	90.2	16.7	152.4
Adjustment	0	0	0	0	0	–6.4	–1.2	–7.6

Note: Totals may not add due to rounding

L.5.7 Deliverability of capex proposal

This section examines the methods proposed by EnergyAustralia to deliver its proposed capex program within the next regulatory control period in the context of determining whether the AER is satisfied that EnergyAustralia's forecast capex reasonably reflects the capex criteria.

EnergyAustralia proposal

EnergyAustralia recognised the need to increase its resources to deliver the proposed capex program and stated that is has taken measures to ensure that it is able to do so. It proposes to:

- increase the capability of its staff through the use of standardised designs, advanced design software, network automation and the deployment of mobile computing
- increase the work undertaken by contractors, for example, for cable laying, civil and building work
- establish alliance agreements with private sector construction companies and consultants to undertake major projects under turn-key-style arrangements.[1123]

Submissions

The EMRF considered that the AER must ensure that capex claims for augmentation and replacement:

> … can be justified in terms of ability to implement in the current economic climate and represents a reasonable assessment in terms of fundamentals underpinning a sensible capex program.[1124]

EnergyAustralia's stated that its licence conditions, generally, do not allow its capacity driven projects to be deferred beyond 2014. EnergyAustralia also noted that, for replacement expenditure, its planning process considered the long-term (that is, 15 to 20 year) risk to the network. It stated that the consequences of delaying these strategic replacement programs could inhibit effective supply from the network and result in further significant increases in replacement expenditure in the 2014–19 regulatory control period.[1125]

Consultant review

Wilson Cook reviewed EnergyAustralia's implementation plans and considered that there were no reasons to conclude that the necessary resources could not be mobilised to implement the program. It concluded that EnergyAustralia had put forward a reasonable implementation strategy.[1126]

AER considerations

The AER has reviewed matters relating to the deliverability of EnergyAustralia's proposed forecast capex. It notes that EnergyAustralia's forecast capex program represents a significant increase compared to that undertaken in the current regulatory control period. In light of this, EnergyAustralia notes that, in the absence of any

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[1123] EnergyAustralia, *Regulatory proposal*, p. 75.
[1124] EMRF, p.16.
[1125] EnergyAustralia, *Response to request for submissions*, p. 4.
[1126] Wilson Cook, volume 2, p. 40.

increases in the rate of physical investment, increases in costs above CPI have contributed approximately 10 per cent to the observed increase in capex between the current and next regulatory control periods.[1127]

As figure L.1 illustrates above, EnergyAustralia's capex over the current regulatory control period has increased by approximately $140 million (or 23 per cent) in real terms each year. Notwithstanding the significant (50 per cent) increase in expenditure for 2009–10, the AER expects EnergyAustralia to be able to achieve similar rates of expansion over the next regulatory control period in a sustainable fashion.

The AER notes that significant analysis has been undertaken by EnergyAustralia to match its capital program to projected levels of resources and expansion of its delivery capability. EnergyAustralia reviewed all major projects to assess whether they could be deferred while maintaining compliance with its licence conditions. This analysis included an assessment of the potential impacts of demand management.[1128]

The AER also notes EnergyAustralia's delivery strategy which seeks to increase the capability of EnergyAustralia's staff, increase the work undertaken by accredited service providers, outsources major projects to contractors and utilise strategic alliances.[1129]

The AER notes, however, that the other NSW DNSPs and TransGrid have also proposed increases of similar magnitude and this will result in an increased demand for equipment and services at the same time. There is also a risk EnergyAustralia may face financial resource constraints should the current credit crisis persist.[1130] Physical resource constraints are also likely to be addressed, to some extent, by an expectation that the Australian economy is entering a period of reduced activity which will see a decline in demand for resources from other sectors of the economy.

Based on its own review of EnergyAustralia's proposed delivery and deferral strategies, and the advice of Wilson Cook, the AER is satisfied that the deliverability of the forecast capex program will not be constrained by resource availability. The AER considers that EnergyAustralia's approach to determining future resource requirements is sound and its existing, and future, plans to ensure program deliverability are robust. The AER also considers that the deliverability of EnergyAustralia's forecast capex program is consistent with the capex objectives generally, and in so far as this aspect is concerned is satisfied it reasonably reflects the capex criteria.

[1127] EnergyAustralia, *Regulatory proposal*, Attachment 11.1, p. 4.
[1128] EnergyAustralia, *Regulatory proposal*, p. 74.
[1129] EnergyAustralia, *Regulatory proposal*, p. 75.
[1130] The AER notes that the NSW Government's Mini Budget 2008–09 provides for an $857 million reduction over three years in the borrowing capacity of the NSW DNSPs and TransGrid. The AER has assessed this financing constraint against the proposed capex programs from 2009–10 to 2011–12, and is satisfied that this need not adversely impact on the deliverability of the program. The reduction in the borrowing program represents a relatively small proportion of the capex program and its impact may be offset by increased internal efficiencies in each of the businesses and or by a change in the timing of dividend payments to the to the shareholder. See: <http://www.treasury.nsw.gov.au/__data/assets/pdf_file/0016/12706/08–09_Mini-Budget.pdf>

However, given the concurrent levels of investment proposed for the broader NSW electricity network, the AER will carefully monitor the expenditures of EnergyAustralia on an annual basis and through its annual regulatory reports will publicly publish the actual capex spent by EnergyAustralia, including any under or over spends if they occur.

L.6 AER conclusion

The AER has reviewed EnergyAustralia's proposed forecast capex allowance and, for the reasons outlined in this appendix, is not satisfied that the proposed forecast capex allowance of EnergyAustralia reasonably reflects the capex criteria, under clause 6.5.7(c). In reaching this conclusion, the AER has regarded the capex factors set out in 6.5.7(e). In particular the AER considers:

- the non-civil zone substation capex of a prudent operator in the circumstances of EnergyAustralia is 3 per cent less than that proposed by EnergyAustralia

- the expenditure associated with EnergyAustralia's application of input cost escalators does not reflect a realistic expectation of the cost inputs required to achieve the capex objectives

- EnergyAustralia's inclusion of the 'black spot' reliability program is not consistent with the capex objectives and accordingly the AER not satisfied that the associated costs reasonably reflect the capex criteria

- the proposed capex for the replacement of feeders 908 and 909, which were the subject of an AER contingent project decision, did not comply with the relevant transitional provision relating to the treatment of contingent projects for EnergyAustralia (clause 11.6.19(g)).

As the AER is not satisfied that the proposed capex allowance reasonably reflects the capex criteria, under clause 6.5.7(d) the AER must not accept the forecast capex proposed by EnergyAustralia. Under clause 6.12.1(3)(ii), the AER is therefore required to provide an estimate of the capex for EnergyAustralia over the next regulatory control period it is satisfied reasonably reflects the capex criteria, taking into account the capex factors. Taking into account the adjustment listed above, this allowance is $8435 million, which is outlined in tables L.19 and L.20.

Table L.19: AER's draft decision on EnergyAustralia's distribution capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total EnergyAustralia proposed capex	1319.7	1432.8	1611.2	1483.6	1533.3	7380.6
Correction of errors	–15.2	–20.4	–24.6	–17.1	–22.8	–100.0
Adjustment for cost escalators	3.0	–1.6	–15.2	–25.5	–44.1	–83.5
Adjustment for substation cost estimates	–4.3	–5.9	–5.0	–4.3	–3.5	–23.0
Adjustment for 'black spot' reliability project	–3.2	–3.2	–3.2	–3.3	–3.3	–16.2
Total AER approved capex allowance	1300.0	1401.8	1563.1	1433.4	1459.6	7157.9

Table L.20 AER's draft decision on EnergyAustralia's transmission capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total EnergyAustralia proposed capex	264.2	170.5	266.6	346.7	229.9	1278.0
Correction of errors	11.1	12.4	6.2	5.9	8.8	44.4
Adjustment for cost escalators	–3.4	–1.2	–5.9	–9.7	–6.9	–27.0
Adjustment for substation cost estimates	–1.6	–1.7	–2.0	–3.2	–2.4	–10.9
Adjustment for replacement of feeders 908 & 909	–6.4	–1.2	–	–	–	–7.6
Total AER approved capex allowance	264.0	178.9	264.9	339.7	229.3	1276.9

Appendix M: Integral Energy forecast capital expenditure

M.1 Introduction

This appendix is to be read in conjunction with chapter 7 of this draft decision. It sets out the AER's detailed considerations and conclusions on Integral Energy's proposed capex allowance for the next regulatory control period which it is satisfied reasonably reflects the capex criteria. The general approach used by the AER to assess Integral Energy's capex proposal and the relevant regulatory requirements is set out in chapter 7. This appendix includes:

- an overview of Integral Energy's capex proposal
- specific comments on the proposal from stakeholders
- the review and findings of the AER's consultant, Wilson Cook
- the issues and the AER's reasoning and considerations, including a discussion of proposed capex by category
- the AER's conclusions on and estimate of the forecast capex allowance for Integral Energy it is satisfied reasonably reflects the capex criteria for the next regulatory control period.

M.2 Integral Energy proposal

Integral Energy proposed a capex allowance totalling $2953 million ($2008–09) for the next regulatory control period. Table M.1 shows the annual profile of Integral Energy's capex proposal by category. Figure M.1 compares Integral Energy's forecast capex with actual expenditure incurred in the current regulatory control period.

Integral Energy's proposed forecast capex for the next regulatory control period is approximately 58 per cent higher than that it will spend in the current regulatory control period. Integral Energy's increased capex requirement is driven by network demand growth, renewal and replacement of ageing assets and network augmentation required to comply with regulatory obligations. Integral Energy noted collectively, replacement, augmentation and compliance expenditure account for 87 per cent of its total forecast capex program.[1131]

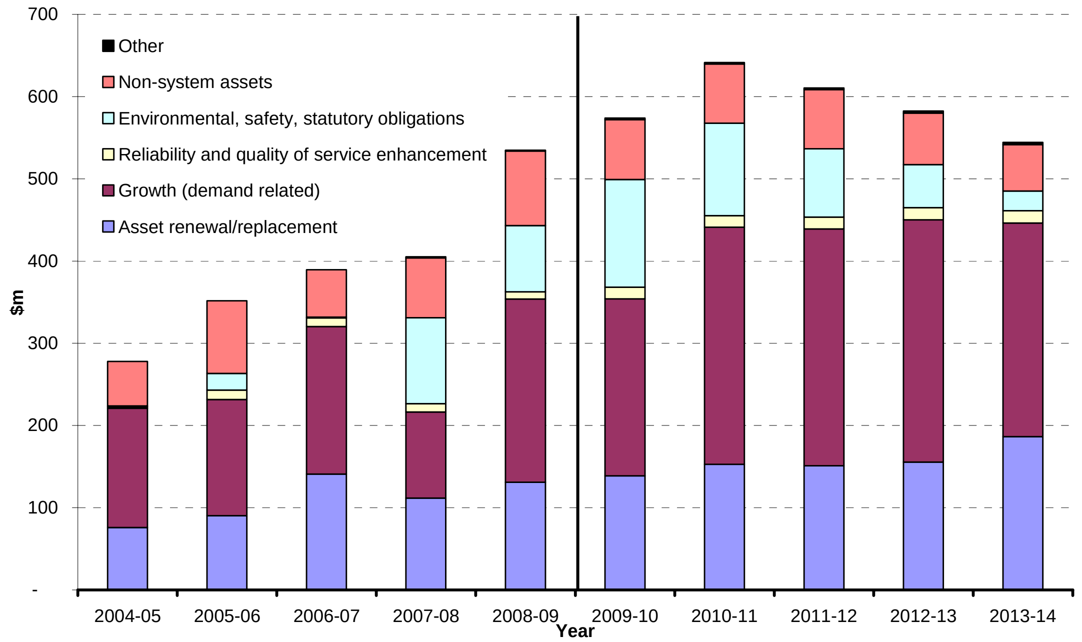
[1131] Integral Energy, *Regulatory Proposal*, p. 110.

Table M.1: Integral Energy's capex proposal by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Growth	215.2	288.3	288.1	294.9	259.8	1346.2
Asset renewal/replacement	138.8	152.8	151.0	155.4	186.5	784.4
Reliability and quality of service enhancement	14.3	14.2	14.4	14.7	14.9	72.6
Compliance obligations	131.1	112.2	83.3	52.5	23.9	402.9
Other (emergency spares)	1.8	1.8	1.8	2.5	2.5	10.5
Total System	501.1	569.4	538.6	519.9	487.6	2616.6
Non–system assets	72.8	72.1	71.8	62.6	56.7	336.1
Total	573.9	641.5	610.4	582.5	544.3	2952.7

Source: Integral Energy, *Regulatory proposal*, p.10.
Note: Totals may not add up due to rounding.

Figure M.1: Integral Energy's actual and proposed capex by category ($m, 2008–09)



Source: Integral Energy, *Regulatory proposal*, RIN template 2.2.1. Data for 2004–09 converted to 2008–09 dollars.

Integral Energy proposed $1346 million augmentation capex, which represents an increase of approximately 70 per cent (in real terms) on the current period. Integral Energy considered this expenditure is required to serve forecast peak demand of 3.6 per cent annually, as well as increased customer numbers and energy consumption. Integral Energy stated its network is predominantly summer peaking, and is being affected by an increasing number of high temperature events and lower equipment ratings during summer periods.[1132]

Integral Energy further proposed $784 million in asset renewal and replacement capex, an increase of 43 per cent (in real terms) on the current period. Of this, Integral Energy proposed to invest $417 million in transmission and zone substations, $142 million in distribution mains and $79 million in transmission.[1133] An ageing asset base, declining serviceability and deterioration of the overall system load factor are the justifications provided by Integral Energy for increases in asset renewal and replacement capex.[1134]

For the next regulatory control period, Integral Energy forecast capex of approximately $403 million to satisfy statutory and compliance obligations. This increase is nearly double the capex on this program in the current regulatory control period. Integral Energy stated this capex largely reflects expenditure for compliance with the NSW Design Reliability and Performance (NSW DRP) licence conditions. Expenditure in this category for the next regulatory control period included investment on zone substations and distribution feeders of $228 million and $111 million, respectively.[1135]

Integral Energy proposed non–system capex for the next regulatory control period is approximately 3 per cent lower when compared with the current regulatory control period. Its motor vehicle capex (down 0.8 per cent, in real terms) is driven by forecast increases in staff numbers. It also noted its ICT capex is 27 per cent above that for the current regulatory control period and justified this increase against efficiency needs and subsequent business automation. Integral Energy stated specific ICT work programs include:[1136]

- outage management system development and integration
- field force automation
- geographic information system upgrade and enhancement
- program management systems.

Integral Energy noted its proposed forecast capex on land and buildings in the next regulatory control period is approximately 38 per cent (in real terms) lower than that of the current period, given the significant expenditure that occurred in the current regulatory control period. Integral Energy stated the primary drivers of this land and buildings capex include the redevelopment, modification and expansion of sites to achieve safe and environmentally sound work practices and compliance requirements.[1137]

[1132] Integral Energy, *Regulatory proposal*, p. 66.
[1133] Integral Energy, *Regulatory proposal*, p. 115.
[1134] Integral Energy, *Regulatory proposal*, pp. 65, 110.
[1135] Integral Energy, *Regulatory proposal*, pp. 117–118.
[1136] Integral Energy, *Regulatory proposal*, pp. 119–120.
[1137] Integral Energy, *Regulatory proposal*, p. 120.

Integral Energy has based its proposed forecast capex for all categories on forecast project and program requirements using assumed unit costs taken from historic contract values. It stated all costs are calculated in real 2007-08 dollars then escalated according to real input price changes as well as one year of CPI to derive its proposal in 2008–09 dollar terms.[1138]

M.3 Submissions

The AER received one submission from the Energy Markets Reform Forum (EMRF) which commented specifically on Integral Energy's forecast capex. The EMRF noted that, based on its trend analysis, Integral Energy appears to be seeking capex well in excess of its historical trend of perhaps 10 per cent of its claimed capex.[1139]

Comments relating to the NSW DNSPs' capex proposals generally are addressed in chapter 7 of this draft decision.

M.4 Consultant review

The AER engaged Wilson Cook to provide an independent assessment of Integral Energy's proposed capex and make recommendations on allowances for prudent capex derived using efficient costs for the next regulatory control period.

As part of its review, Wilson Cook evaluated Integral Energy's regulatory proposal, sought additional information on specific projects and programs and engaged in further discussions with Integral Energy. In summary, based on its review, Wilson Cook found that:[1140]

- the primary factors driving Integral Energy's capex program were the continued growth in peak demand, replacement of ageing assets and the reliability and security of supply requirements in its licence conditions
- the projects appeared prudent and efficient
- the cost estimates used for project costing were generally reasonable for the scope of work concerned
- the application of weighted real price escalators for individual inputs appeared reasonable[1141]
- the capex program is deliverable.

In assessing Integral Energy's forecast capex, under its terms of reference, Wilson Cook considered the following key factors:[1142]

[1138] Integral Energy, *Regulatory proposal*, p. 124.
[1139] EMRF, p. 17.
[1140] Wilson Cook, volume 3, pp. 8–31.
[1141] Wilson Cook did not express a reasonableness of input assumptions regarding future cost movements, nor verify Integral Energy's methodology.
[1142] Wilson Cook, volume 1, pp. 7–12.

- prudence and efficiency of the proposed expenditures[1143]
- external factors and obligations identified by Integral Energy
- consistency of expenditure projections with the demand forecasts accepted by the AER
- unit costs, escalation rates and methodologies for materials cost escalation
- expenditure drivers including the need to address demand growth, ageing assets and safety and environmental issues
- appropriateness and consistent application of policies and procedures.

As shown in table M.2, Wilson Cook concluded Integral Energy's system capex is reasonable in scope and cost with the exception of elements of replacement capex, where a reduction totalling $29 million is recommended.

Wilson Cook's specific findings on each area of Integral Energy's capex proposal are described in sections M.5.1 to M.5.5 of this appendix.

Table M.2: Wilson Cook's recommended capex allowance for Integral Energy ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Integral Energy proposal	573.9	641.5	610.4	582.5	544.3	2,952.7
Less adjustments to system assets						
Other substation renewal projects	–	–	–	–	–15	–15
Unspecified civil renewals	–	–2	–2	–2	–1	–7
Unspecified sub–transmission renewal	–	–	–1	–2	–3	–6
Wilson Cook recommendation	573.9	639.5	607.4	578.5	525.3	2924.7

Source: Wilson Cook report, Volume 3, pp. 9, 27.
Note: Totals may not add up due to rounding.

M.5 Issues and AER considerations

This section presents the AER's consideration of the following aspects of Integral Energy's proposal:

1143 Wilson Cook, volume 1, p. 9. Where Wilson Cook has considered there was an appropriate balance between the factors it considers comprises prudence and efficiency, it has concluded in its report that the expenditure is reasonable.

- its policies and procedures
- its cost estimation processes
- the application of input cost escalators
- proposed expenditure by major category
- the deliverability of the proposal.

M.5.1 Policies and Procedures

This section examines whether Integral Energy's capex planning practices are appropriate and provide a framework that is likely to result in prudent and efficient investment decisions. The AER considers that assessing these practices in this manner is relevant for determining whether the AER is satisfied that Integral Energy's forecast capex reasonably reflects the capex criteria.

Integral Energy's proposal

In considering its capital program, Integral Energy stated its planning processes explicitly considered the drivers of expenditure set out in the capex objectives of the NER. Further, Integral Energy concluded its analysis and governance processes address matters raised in the NER criteria.[1144]

Integral Energy's approach to network planning and asset management is subject to oversight by its executive level Capital Governance Committee, chaired by its CEO. Up until the end of 2007, the role of Integral Energy's Capital Governance Committee was to:[1145]

- consider proposals for network system capex projects and programs
- consider proposals for ICT capex, projects and programs
- consider proposals for property acquisition, construction and maintenance capex projects and programs
- consider proposals for motor vehicle capex projects and programs
- ensure the selection and delivery of capex projects and programs are consistent with corporate objectives, specific identified strategies, operational plans and regulatory requirements.

From 2008, the Capital Governance Committee's role was expanded to include opex for network assets.[1146]

Integral Energy has applied a network planning framework which is represented in its 10 year strategic asset management plan. Integral Energy states that its strategic asset

[1144] Integral Energy, *Regulatory proposal*, p. 126.
[1145] Integral Energy, *Regulatory proposal*, p. 87.
[1146] Integral Energy, *Regulatory proposal*, p. 87.

management plan represents a single coordinated asset management plan which documents how its individual network capital and maintenance plans support strategic outcomes.[1147] The strategic asset management plan specifically takes into account:

- externally imposed obligations and requirements
- information about the network (e.g. capacity, condition and age)
- forecasts of demand growth and connections by location.

Consultant review

Wilson Cook considered Integral Energy to have followed reasonable policies and procedures, including the identification of need and least cost solutions when making investment decisions.[1148] Wilson Cook stated much of the documentation provided was conventional, however, it noted weaknesses in Integral Energy's cases for replacement capex, where expenditure provisions deviated from historical trends. Wilson Cook concluded Integral Energy provided insufficient documentation to justify proposed replacement related capex expenditure departing from previous trends.[1149]

AER considerations

The AER has reviewed Integral Energy's capital governance framework and considers it contains appropriate delivery strategies, consistent with good industry practice. During meetings with Integral Energy planning staff and Wilson Cook, the AER reviewed Integral Energy's approach to network planning processes and asset management. In its review, the AER considered a sample of key capex projects which are major contributors to Integral Energy's proposed capital program.

The AER notes Integral Energy's approach to network planning and asset management is subject to end-to-end oversight by an executive level Capital Governance Committee, chaired by Integral Energy's Chief Executive Officer. The Capital Governance Committee focuses on considering proposals for network system capex and opex programs, ICT capex, property-related capex, motor vehicle capex. Further, the Committee ensures the selection and delivery of capex projects and programs are consistent with corporate objectives, specified identified strategies, operational plans and regulatory requirements.

Overall, the AER is satisfied that Integral Energy observed appropriate processes and procedures in determining and authorising the scope, timing and need for the proposed projects. This conclusion is consistent with the views expressed by Wilson Cook, which have not recommended any adjustments to Integral Energy's forecast capex based on its findings in relation to Integral Energy's capital governance framework.

The AER is satisfied that Integral Energy's planning processes and proposed levels of investment demonstrate a level of assurance and good practice on the part of Integral

[1147] Integral Energy, Regulatory proposal, p. 77.
[1148] Wilson Cook, volume 3, pp. 15 and 23.
[1149] Wilson Cook, volume 1, p.12; Wilson Cook, volume 3, pp. 21–23.

Energy that supports the observation that its system capex proposal is based on an effective and efficient identification of investment needs. The AER considers this to be relevant in determining whether Integral Energy's forecast capex reasonably reflects the capex criteria.

M.5.2 Cost estimation processes

This section examines the methods adopted by Integral Energy to estimate costs for identified investment needs in the context of determining whether the AER is satisfied that its forecast capex reasonably reflects the capex criteria.

Integral Energy's proposal

Integral Energy has based its proposed capex for all categories on forecast project and program requirements using assumed unit costs taken from historic contract values.[1150]

Integral Energy commissioned Parsons Brinckerhoff Australia Pty Ltd (PB) to advise whether the associated costs of its proposed capex program are consistent with requirements of the transitional chapter 6 rules and appear efficient and prudent. PB reviewed a sample of Integral Energy's proposed projects and in each case determined both costs and unit rates appeared prudent and reasonable.[1151]

Consultant review

The AER engaged Wilson Cook to develop independent forecasts of unit costs in advance of receiving the DNSPs' proposals to enable cost comparisons across DNSPs when preparing their expenditure forecasts. Wilson Cook found, however, that this was not possible as the DNSPs used various methods for cost estimation, relying generally on the reported cost of completed work, internal costing programmes or independent reviews and not on types of unit costs which would enable such comparisons.[1152]

Wilson Cook considered Integral Energy's proposal and PB's review, and concluded Integral Energy's cost estimates were reasonable for the scope of work concerned.[1153]

AER considerations

The AER reviewed Integral Energy's proposed unit rates and PB's comparative review of these costs. The AER noted PB's review that forecast capex for nine zone substations was reasonable, although they had been 'generically estimated at $30m' leading it to suggest that Integral Energy 'endeavour to be more prescriptive in describing the anticipated scope of works for such projects'.[1154] Also, PB noted that Integral Energy's cost estimates for major projects and programs, particularly replacement costs for transformers, were on the high side of its benchmark and Integral Energy's own historic costs. Integral Energy advised forecast estimates

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[1150] Integral Energy, *Regulatory proposal*, p. 124.
[1151] PB, *Review of assumptions underpinning capital and operating expenditure forecasts*, May 2008, p. 29.
[1152] Wilson Cook, volume 1, p. 10.
[1153] Wilson Cook, volume 3, p. 24.
[1154] PB, *Review*, May 2008, p. 60.

reflected the use of the latest contract prices and installation costs.[1155] The AER anticipates that these updated unit costs would be verifiable and consistently applied by Integral Energy, and notes PB's concern that the consistency and transparency of the cost estimating approach could be improved. However, while PB has highlighted some concerns with Integral Energy's estimation processes, it concludes Integral Energy appears to have robust processes in place to produce reasonable cost estimates for projects and programs.[1156] The AER is satisfied the unit costs applied by Integral Energy reflect both recent historical expenditure and good industry practice and appear efficient within the context of the industry as it presently operates.[1157]

The AER also notes Integral Energy has instituted a productivity improvement program entailing a 2 per cent per annum improvement in labour productivity which is reflected in the forecast of capitalised overhead expenditure. The AER notes that Integral Energy has an integrated capex and opex budgeting process and applied the 2 per cent productivity factor to the overhead pool prior to allocating capitalised overheads, thus incorporating savings within capitalised overheads.[1158] This represents a pro-active measure by Integral Energy and serves to underline the efficiency of its proposed cost inputs.

The AER is satisfied unit costs reasonably reflect the capex criteria, in particular, a realistic expectation of efficient cost inputs required by a prudent operator in the circumstances of Integral Energy to achieve the capex objectives.

M.5.3 Application of input cost escalators

This section examines whether the cost escalators used by Integral Energy to develop its capex proposal reflect a realistic expectation of input costs required to meet the capex objectives in the context of determining whether the AER is satisfied that its forecast capex reasonably reflects the capex criteria.

Integral Energy proposal

Integral Energy has anticipated that costs associated with a number of its key inputs will increase faster than CPI and proposed that its capex be adjusted to account for this. Integral Energy commissioned the Competition Economists Group (CEG) to prepare forecasts for real price changes in various inputs that form part of Integral Energy's capex proposal (e.g. land, labour).[1159] Further details on CEG's recommended escalators and underlying methodologies applicable to the NSW DNSPs are contained in appendix N.

The impact of Integral Energy's proposed input cost escalators is illustrated in table M.3.

[1155] PB, *Review*, May 2008, p. 26.
[1156] PB, *Review*, May 2008, p. 26.
[1157] Sections M.5.3 and M.5.4.2 further discuss cost estimation processes.
[1158] Integral Energy, email to AER, 12 September 2008.
[1159] Integral Energy, *Regulatory proposal*, p. 122.

Table M3: Impact of Integral Energy's cost escalator factors

	2009–10	2010–11	2011–12	2012–13	2013–14
Base capex ($m 2007–08)	555.6	616.9	580.4	547.7	506.8
Capex with real cost escalators ($m 2007–08)	561.0	627.1	596.7	569.4	532.1
Real capex cost escalation ($m 2007–08)	5.5	10.2	16.3	21.8	25.3
CPI 2007–08 – 2008–09	1.023	1.023	1.023	1.023	1.023
Base capex ($m 2008–09)	568.4	631.1	593.7	560.3	518.4
Capex with real cost escalators ($m 2008–09)	573.9	641.5	610.4	582.5	544.3
Real capex cost escalation ($m)	5.6	10.4	16.7	22.3	25.9

Source: Integral Energy, email to AER Integral Energy: Escalators- request for information, 17 October 2008.

Integral Energy's weightings for each capex component are detailed in table M.4.

Integral Energy commissioned PB to review the application of its proposed cost escalators to base estimates for specialist labour and materials for the next regulatory control period. PB found forecasts of major input cost escalators have been applied in accordance with recommendations outlined in CEG's report and, on the balance of information, appear reasonable.

PB also noted the following observations affecting the amount of capex forecast by Integral Energy:[1160]

- more than 34 per cent of the capex that occurred in the base year (2006–07) was not subjected to price escalation resulting in a conservative application of the escalation factors (i.e. this proportion is not increased in real terms)
- Integral Energy classified its costs into various components based on expenditure in 2006–07, which, in the case of land, may overstate the costs escalated in each year as expenditure on land as a proportion of total capex is actually less during the period
- the proportion of labour adopted (25.6 per cent) appears to be relatively low by comparison to recent submissions to the AER
- Integral Energy should consider applying the real escalators to all projects rather than just those that are yet to be approved by its Board, given that 'there should be no difference between the application of labour and material real cost escalators based on the rigour of the cost estimating technique or whether the project has been endorsed or not'.[1161] PB notes that this would have the effect of increasing the amount of proposed capex from $82 million to $108 million.

[1160] PB, *Review*, May 2008, p. 56.
[1161] PB, *Review*, May 2008, p. 56.

Table M.4: Integral Energy's weightings for each capex component

	Weight	2009	2010	2011	2012	2013	2014
Labour	25.6	3.6	3.9	1.9	2.8	3.5	3.7
Primary Equipment	4.3	0.1	–0.3	–0.2	–0.1	–0.1	–0.1
Secondary Systems	0.9	0.0	0.0	0.0	0.0	0.0	0.0
Oil	0.2	12.3	–3.8	–1.3	–0.5	–2.0	–0.9
Power Transformers	4.3	0.1	–0.8	–0.5	–0.3	–0.4	–0.4
Distribution Equipment	2.0	0.1	–0.3	–0.2	–0.1	–0.1	–0.1
Distribution Transformers	5.2	0.1	–0.8	–0.5	–0.3	–0.4	–0.4
Copper Cable	1.7	–1.1	–3.0	–2.0	–1.3	–1.5	–1.4
Aluminium Cable	0.8	2.2	–0.4	–0.2	0.1	–0.1	0.0
Concrete Poles	0.6	0.0	0.0	0.0	0.0	0.0	0.0
Wood Poles	0.4	0.0	0.0	0.0	0.0	0.0	0.0
Copper Conductor	0.1	–2.4	–4.1	–2.7	–1.8	–2.0	–2.0
Aluminium Conductor	0.5	2.1	–0.3	–0.1	0.2	0.0	0.0
Buildings	2.3	2.1	0.9	0.7	1.1	1.9	2.6
Civil	5.6	2.1	0.9	0.7	1.1	1.9	2.6
Fencing	1.6	2.1	0.9	0.7	1.1	1.9	2.6
Major Projects (Land)	3.8	4.1	4.1	4.1	4.1	4.1	4.1
Capitalised Overheads (ex land)	5.7	0.0	0.0	0.0	0.0	0.0	0.0
Balance	34.3	0.0	0.0	0.0	0.0	0.0	0.0
Annual Escalator (above CPI)		1.33	1.08	0.62	0.92	1.16	1.28
Cumulative over 2007/08		1.33	2.43	3.06	4.01	5.22	6.57

Source: Integral Energy, *Regulatory proposal*, p. 124.

Consultant review

Wilson Cook did not consider the development of escalator rates as appropriate, given Integral Energy obtained independent advice to project future material and price movements. Wilson Cook considered escalation rates assumed for the main material or asset categories as modest and did not reflect a continuation of the rapid escalation of costs evident in the electricity supply industry experienced in Australasia in recent years.[1162]

AER considerations

The AER's detailed considerations and decision on each escalator and associated forecasting method arising out of CEG's recommendations are contained in appendix N to this draft decision.

With respect to the escalators proposed by Integral Energy as part of its forecast capex allowance, the AER has made adjustments to the method used to forecast copper, steel and aluminium as proposed by CEG, and used updated data with respect to forecast construction costs, crude oil and exchange rates which are used in the conversion of costs into Australian dollar terms.

The AER considers that its conclusions from the recent ElectraNet decision are still applicable with respect to the methodology used for estimating each of these cost factors (i.e. copper, aluminium and crude oil). In most cases, CEG has not presented any new compelling evidence justifying a departure from the approach previously accepted by the AER (see appendix N).

The AER considers that PB may have overstated the conservative application of Integral Energy's real cost escalators since:

- the AER would expect that, to some extent, cost escalations would be minimised following Board approval of expenditures as the organisation is then able to enter into contracts and by doing so fix the price of various cost inputs
- the AER does not anticipate that the use of uniform weightings for each year of the regulatory control period is likely to be material for Integral Energy as a DNSP. By comparison, the impact of doing so for TransGrid resulted in a change of $4.7 million to its proposal[1163], which reflects a more heterogenous, transmission investment portfolio from year to year
- the 25.6 per cent of capex which is identified as labour is roughly between the 33.0 per cent proposed by EnergyAustralia and 19.1 per cent proposed by Country Energy[1164]

The AER does note however, that the 34 per cent of capex which Integral Energy has not subjected to real escalation is high by comparison to the 3.6 per cent proposed by EnergyAustralia and zero per cent proposed by Country Energy.[1165]

In summary, the AER is not satisfied that Integral Energy's proposed cost escalation assumptions reasonably reflects the capex criteria, in particular that it is a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives as stated in clause 6.5.7(c)(3). The AER requested Integral Energy to

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1162 Wilson Cook, volume 3, p. 42.
1163 AER, *Draft decision*: *TransGrid transmission determination*, November 2008, pp.71–72.
1164 PB, *Review*, May 2008, p. 57.
1165 PB, *Review*, May 2008, p. 56.

remodel its proposed capex program on the basis of the AER's decision with respect to escalators, which has resulted a $9.3 million reduction.[1166] Accordingly, the AER is satisfied that the reduction of $9.3 million to Integral Energy's forecast capex, as detailed in table M.5 reasonably reflects the capex criteria.

Table M.5: Integral Energy's reduction in capex due to amended real cost escalators ($m, 2008–09)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Cost escalator adjustment	–2.0	–1.4	–1.0	–2.5	–2.4	–9.3

M.5.4 Review by expenditure type

M.5.4.1 Growth capex

This section examines the scope, timing and costs of Integral Energy's proposed expenditure by category (e.g. growth, replacement, compliance, reliability and non–system capex) in the context of determining whether the AER is satisfied that its forecast capex reasonably reflects the capex criteria.

Integral Proposal

Integral Energy proposed growth expenditure of $1346 million in the next regulatory control period, this is an increase of 68 per cent on the current period. Growth expenditure accounts for approximately 46 per cent of its total proposed capex and is shown in table M.6.[1167]

Table M.6: Integral Energy's proposed growth capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	2013–14
Growth capex	215.2	288.3	288.1	294.9	259.8	259.8

Source: Integral Energy, regulatory proposal, p. 104.

Approximately 74 per cent of the proposed growth capex is attributable to major projects and programs. The following major projects comprise the largest items in the program:[1168]

- Liverpool transmission substation establishment and associated works
- Abbotsbury zone substation
- Camellia 132kV busbar and Parramatta CBD West zone substation

[1166] The AER has not fully verified Integral Energy's calculations for the purposes of this draft decision. As such this adjustment is indicative and will be confirmed for the AER's final distribution determination.

[1167] Integral Energy, *Regulatory proposal*, p. 111.

[1168] Integral Energy, *Regulatory proposal*, pp. 113–114.

- Doonside zone substation
- Cheriton Avenue substation.

A further 7 per cent of growth expenditure is attributable to Integral Energy's distribution works program. Expenditure in this category exhibits an increase of ten fold on the current regulatory control period. The distribution works program relates to normal high voltage distribution feeder work and achieving feeder compliance with respect to the NSW DRP licence conditions.[1169]

Approximately 12 per cent of Integral Energy's growth capex relates to customer–driven capex (comprising of industrial and commercial connections, non–urban extensions and underground residential development). Growth in customer numbers estimates the number of new connections required and associated forecast network connection expenditure.[1170]

Integral Energy's other growth related capex includes asset relocations, low voltage development and metering, which collectively account for around 7 per cent of growth capex.[1171]

Integral Energy commissioned PB to review its growth related capex. PB found Integral Energy's documentation was of high quality and demonstrated a systematic approach to the determination of network investment requirements for compliance and growth–related drivers. With respect to Integral Energy's proposed cost estimates for its proposed growth–related capex, PB concluded they appeared efficient and reasonable.[1172]

Integral Energy's growth–related capex is largely explained in terms of serving forecast peak demand throughout the network. Integral Energy produced its own demand forecasts for the next regulatory control period and engaged CRA International (CRA) to review all material underlying assumptions and methodology. Further, CRA was required to verify assumptions and techniques, where appropriate. CRA found Integral Energy's forecasts of maximum demand, energy consumption and corresponding growth rates are:

> … based on sound evidence and are reasonable for the purposes of the 2009 regulatory proposal.[1173]

Consultant review

Integral Energy provided Wilson Cook and the AER with a list of major projects and programs and supporting documentation, including area plans and project justifications. Further, Wilson Cook engaged in discussions with Integral Energy pertaining to its major projects and programs and found Integral Energy planning staff well equipped to provide necessary information and satisfactory responses to questions posed. Wilson Cook considered Integral Energy's network planning

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[1169] Integral Energy, *Regulatory proposal*, p. 112 and appendix J.3.
[1170] Integral Energy, *Regulatory proposal*, p. 112 and appendix J.3.
[1171] Integral Energy, *Regulatory proposal*, pp. 111–112.
[1172] PB, *Review*, May 2008, p. 48.
[1173] CRA International, *Integral Energy: Energy and Demand Forecasting*, May 2008, p.2.

documentation and project justification reasonable however, noted cases where plans remained subject to final design and approval, in accordance with normal distribution engineering practice. Wilson Cook further considered plans for separate works in each area constituted reasonable options for network development.[1174]

Wilson Cook noted Integral Energy's distribution works program was developed from a bottom up assessment for the year ahead and is projected from a base year using data for individual feeders. However, Wilson Cook considered that insufficient documentation was provided for it to review Integral Energy's forecasting methodology. Wilson Cook noted PB's review of Integral Energy's methodology behind its Distribution Works Program, which found that the capex forecasts are reasonable to ensure no feeders are overloaded by 2013–14.[1175]

Wilson Cook noted customer–driven capex reflects direct customer or developer enquiries and information including future development activities, which are subject to considerable uncertainty. Despite limited detail in methods of estimation for this expenditure, Wilson Cook noted it aligns with capex in the current period and therefore appears prudent and efficient.[1176]

Based on its review and the supporting documentation provided by Integral Energy, Wilson Cook concluded that the plans and indicative timing of Integral Energy's proposed growth–related capex were reasonable, and concluded that capex proposed in this category was efficient.[1177]

The AER engaged McLennan Magasanik Associates (MMA) to review Integral Energy's maximum demand forecasts, which underpin its proposed capex program.[1178] MMA found methodological flaws with Integral Energy's global and spatial maximum demand forecasting processes.

MMA found Integral Energy's global maximum demand forecasts were significantly higher than recent history, both starting at a higher level than the trendline, and projecting growth at a rate much faster than recent history.[1179] MMA concluded that the Integral Energy spatial maximum demand forecast methodology was inadequate, and that the spatial maximum demand forecasts are likely to be significantly over-optimistic.[1180] MMA recommended that the AER should view Integral Energy's maximum demand forecasts conservatively and that the AER should be generally conservative in approving its growth driven capex proposal for the next regulatory control period.[1181]

MMA's review and the AER's consideration of Integral Energy's demand forecasts and forecast methodology is further outlined in chapter 6.

1174 Wilson Cook, volume 3, p. 14.
1175 Wilson Cook, volume 3, pp. 14–15.
1176 Wilson Cook, volume 3, p. 15.
1177 Wilson Cook, volume 3, pp. 14 and 18.
1178 MMA, *Regulatory proposal 2009–14 –Review of Integral Energy's maximum demand forecasts*, 15 August 2008, confidential.
1179 MMA, *Integral Energy's maximum demand forecasts,* p. 1.
1180 MMA, *Integral Energy's maximum demand forecasts,* pp. 52–53.
1181 MMA, *Integral Energy's maximum demand forecasts,* p. 5.

AER considerations

In the course of its review, the AER requested Integral Energy to address a number of methodological concerns raised by MMA, and prepare a revised maximum demand forecast consistent with recent trends in maximum demand and corresponding macroeconomic drivers.[1182] The AER requested that a revised capex forecast be prepared on the basis of the revised maximum demand forecast.[1183]

In its response, Integral Energy advised the AER that it had identified an error with its weather normalisation data which, when corrected, reduced the gap between global and spatial demand forecasts. Integral Energy revised its spatial demand forecasts downwards as a result of incorporating MMA's recommendations relating to spot loads and lot releases. Upon incorporating these adjustments, Integral Energy noted that there was no impact on its total capex proposal. It stated that the insensitivity of its growth capex to maximum demand forecasts was due to the bulk of works in this category being already deferred for commissioning at a time beyond that required to meet demand constraints.[1184]

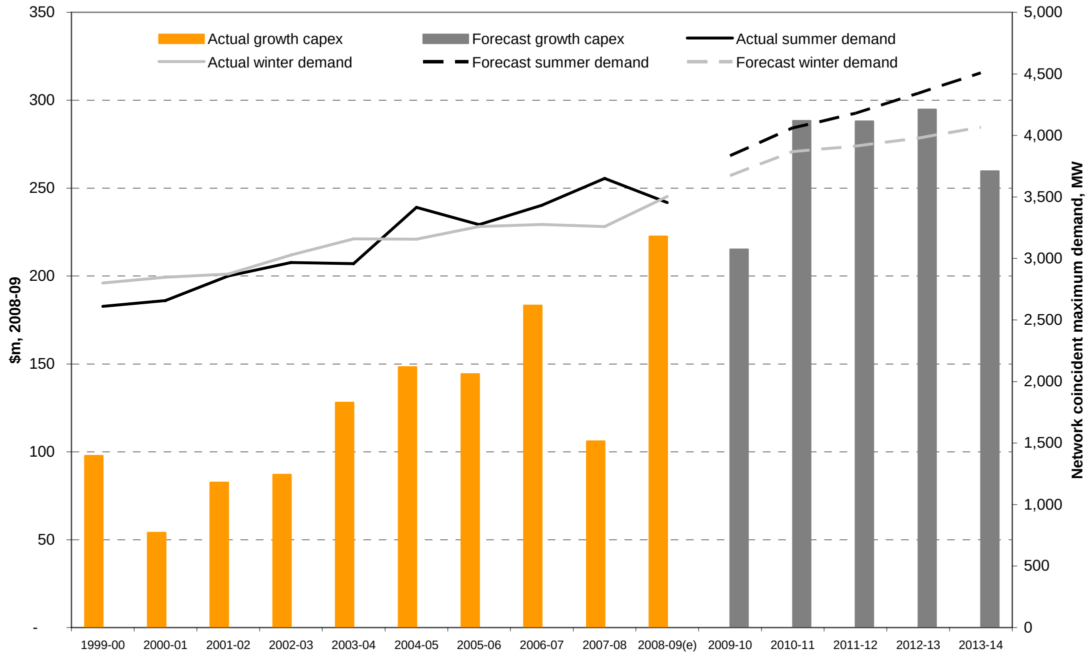
Following Integral Energy's response, the AER reviewed the revised loads for specific zone substations. The AER reviewed existing capacity and projected growth for specified zone substations to identify the required timing for proposed augmentation investment. The AER found the affected proposed capex was driven by augmentation needs, not by forecast system maximum demand. The AER concluded that the revised maximum demand forecast resulted in no material impact on Integral Energy's proposed capex and consider the timing and costs of the augmentation projects to be efficient.

Notwithstanding MMA's recommendations concerning further improvements that Integral Energy could make to its forecasting processes, the AER considers Integral Energy's revised maximum demand forecasts provide a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the transitional chapter 6 rules.

Regarding the comments made by the EMRF, the AER has undertaken a comparison of changes in Integral Energy's growth capex relative to peak demand growth, as illustrated in figure M.2.

[1182] AER, letter to Integral Energy, 11 August 2008.
[1183] AER, letter to Integral Energy, 11 August 2008.
[1184] Integral Energy, response to 11 August 2008 letter from the AER on Integral Energy's Maximum Demand forecast for the 2009–14 regulatory period, 29 August 2008.

Figure M.2: Integral Energy's growth capex and peak demand



Source: AER calculations; Integral Energy, RIN templates 2.2.1, 2.3.8.

In general, Integral Energy's growth capex appears to show some correlation with growth in peak demand for the system as a whole, although the extent to which a trend is present in the historic data depends on the accuracy of the estimated capex for 2008–09. The step increase in expenditure in 2010–11 is matched by a higher than trend increase in forecast summer peak demand. Notwithstanding the accuracy of Integral Energy's demand forecasts, this high level analysis does not identify any significant disjoint between growth capex and peak system demand. The AER notes factors including the impact of licence conditions and customer numbers have contributed to Integral Energy's growth capex and drive investment required for the whole network. In contrast, demand at the disaggregated level is a better indicator of the key drivers of growth capex and drives investment for individual parts of the network.[1185]

The AER has reviewed Integral Energy's supporting documentation, including PB's review of assumptions underpinning Integral Energy's capex forecasts, and engaged in discussions with Integral Energy about its growth-related capex. The AER has also considered the advice provided by Wilson Cook and its own assessment of the impact of demand forecasts on the timing of specific projects. Taking into account all of these factors, the AER is satisfied that the proposed growth-related capex reasonably reflects the efficient costs required to achieve the capex objectives and is based on a realistic expectation of demand forecasts and cost inputs, consistent with the capex criteria in clause 6.5.7(c).

[1185] Integral Energy's demand management projects are discussed in Chapter 14 of this draft decision.

M.5.4.2 Replacement capex

Integral Energy's proposal

Integral Energy proposed asset renewal and replacement expenditure in the amount of $784 million ($2008–09), forecast to increase approximately 42 per cent (in real terms) from the current regulatory control period. Replacement capex represents around 27 per cent of the total forecast capex program. Table M.7 below sets out the main replacement capex projects and programs for the next regulatory control period.

Table M.7: Forecast asset renewal/replacement capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Distribution Substations	10.3	10.4	10.4	11.5	11.7	54.3
Distribution Mains	25.7	26.2	27.6	29.4	32.8	141.8
Transmission Substations	68.2	85.5	79.5	80.3	103.8	417.3
Transmission Mains	15.2	13.3	15.2	16.4	19.1	79.2
Metering	8.9	8.9	10.8	11.0	7.0	46.7
Other renewal/replacement	10.4	8.4	7.4	6.8	12.1	45.1
Total Renewal/Replacement	138.8	152.8	151.0	155.4	186.5	784.4

Source: Integral Energy, *Regulatory proposal*, p. 115.

Approximately 53 per cent of Integral Energy's total forecast replacement program is directed at transmission and zone substation equipment ($417 million collectively), given nearly a third of such equipment is now at, or close to, the end of its useful life.[1186]

The major asset renewal/replacement projects identified by Integral Energy include the following:[1187]

- Granville zone substation rebuild – to be rebuilt as a 132/11kV substation
- Penrith transmission substation – rebuild the substation
- Rydalmere zone substation renewal – replacement of 66kV and 11kV switchgear
- Guildford transmission substation renewal – proposed to completely renew the substation.

Other specified substation projects, for which business cases are yet to be developed, are outlined in Integral Energy's Strategic Asset Renewal Plan.

1186 Integral Energy, *Regulatory proposal*, p. 114. Integral note 25 of its zone and sub–transmission substations are 45 years or older, and an additional 70 will reach 45 years within the next 10 years.
1187 Integral Energy, *Regulatory proposal*, appendix J.1.

Integral Energy's proposed expenditure for distribution mains includes the replacement of high voltage steel mains, cast iron cable terminations and air break switches, and replacement of low voltage concentric aluminium cable. The sub–transmission mains category includes the replacement of underground pilot cables, wood pole replacement and steel tower refurbishments.

Other replacement capex categories included in Integral Energy's replacement capex includes the replacement of distribution substations, meters, relays, remote terminal units and communication system items.

Consultant review

Wilson Cook reviewed in detail a number of Integral Energy's transmission and zone substation projects. In each instance, Wilson Cook considered the proposed expenditure to be prudent and efficient.[1188]

With respect to other substation renewal projects, Wilson Cook reviewed documentation provided by Integral Energy and engaged in further discussion with its planning staff. Wilson Cook accepted that the scope of work involved and timing may change in such projects, yet noted expenditure in this category increased in the final year to a level higher than historical trends. Wilson Cook concluded a level of expenditure based on established levels of work ought to take precedence over an increased level of expenditure which deviates from expenditure trends and was not supported by adequate reasoning. Further information could have been provided to substantiate claims for increased capex under this category. Subsequently, Wilson Cook recommended an adjustment of $15 million to the provision for other substation renewal projects within the next regulatory control period.[1189]

In reviewing Integral Energy's replacement capex pertaining to transformers, Wilson Cook was satisfied that Integral Energy followed reasonable policies and procedures to determine its forecast capex. Wilson Cook considered the proposed number of transformer replacements as reasonable, as it is consistent with recent replacement levels and reflects the age profile of this asset category.[1190]

Wilson Cook further reviewed Integral Energy's substation circuit breaker replacement program. Wilson Cook considered that although quantification of expenditure is not well supported by documentation, forecast expenditure levels are consistent with historical trends and, on balance, accepted these costs as reasonable.[1191]

Wilson Cook undertook a review of the civil works capex proposed by Integral Energy. It considered the specific projects to be prudent, however, it noted the proposed capex for unspecified works lacked sufficient documentation to support justifications in departing from expenditure trends for this capex category. On this basis, Wilson Cook recommended an adjustment of $7 million for the next regulatory

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[1188] Wilson Cook, volume 3, pp. 20–21.
[1189] Wilson Cook, volume 3, p. 21, 27
[1190] Wilson Cook, volume 3, p. 22.
[1191] Wilson Cook, volume 3, p. 22.

control period which better aligned with historical expenditure under this capex category.[1192]

In reviewing Integral Energy's distribution mains category, Wilson Cook considered the scope of the replacement work proposed was consistent with the reported fault rates and that no adjustment was required.[1193]

Wilson Cook considered that Integral Energy's proposed sub–transmission mains activities appeared reasonable, but that the $12 million provision for unspecified works was again not supported by sufficient reasoning or justifications to support the deviations from expenditure trends. Wilson Cook engaged in further discussion with Integral Energy on this expenditure however, concluded that this expenditure should be removed to maintain the same level of expenditure in each of the years within in next regulatory control period.[1194]

With respect to other replacement capex, Wilson Cook was satisfied that the scope, timing and efficiency of the proposed expenditure were reasonable and aligned with historical trends.[1195]

AER considerations

The AER has reviewed documentation provided by Integral Energy, including its strategic asset replacement program, its strategic asset management plan and information relating to specific projects provided during consultation. The AER is satisfied this documentation demonstrates a level of assurance and good practice which supports the need for replacement capex identified by Integral Energy. The AER has also considered the advice provided by Wilson Cook and is satisfied that Integral Energy's replacement capex is generally prudent and efficient. However, as noted by Wilson Cook, the following expenditures result in a divergence from historical levels and have not been sufficiently justified by Integral Energy:[1196]

- $15 million for the provision for other substation renewal projects
- $7 million for the provision for un-specified civil works
- $6 million for the provision for un-specified work on sub–transmission mains.

The AER is not satisfied that Integral Energy's proposed replacement capex reasonably reflects the efficient costs that a prudent operator in the circumstances of Integral Energy would require to achieve the capex objectives. The AER has therefore decided to make an adjustment to Integral Energy's proposed replacement capex totalling $29 million which better aligns with Integral Energy's expenditure trends and reasonably satisfies the capex criteria.

1192 Wilson Cook, volume 3, p. 22.
1193 Wilson Cook, volume 3, p. 22.
1194 Wilson Cook, volume 3, p. 23.
1195 Wilson Cook, volume 3, p. 23.
1196 Wilson Cook, volume 3, p. 27.

M.5.4.3 Reliability and quality improvement capex

Schedule 2 of the NSW DRP licence conditions set minimum reliability standards (SAIDI and SAIFI) across the main feeder categories (CBD, urban, short rural and long rural).[1197] The performance standards include both duration (system average interruption duration index, or SAIDI) and frequency (system average interruption frequency index, or SAIFI) measures.

Integral Energy proposal

Integral Energy has proposed reliability expenditure of $73 million in the next regulatory control period, which is approximately 2 per cent of its total capex proposal. Integral has noted its feeder types are performing well compared to performance standards under the licence requirements.[1198] This is supported by the data in table M.8 which show that Integral Energy's historical average reliability performance is much better than the minimum required under the licence conditions (which were introduced in August 2005 and revised in 2007).

Table M.8: Comparison of SAIDI and SAIFI performance

Year ending June	2004	2005	2006	2007	2008	2009	2010	From 2011
SAIDI- Minutes per customer								
Urban feeder								
Actual	81.0	54.3	66.7	66.0	-	-	-	-
Licence target	n/a	n/a	90	88	86	84	82	80
Short rural								
Actual	202.1	169.8	184.4	175.0				
Licence target	n/a	n/a	300	300	300	300	300	300
SAIFI- Number per customer								
Urban feeder								
Actual	1.1	0.8	0.9	0.9	-	-	-	-
Licence target	n/a	n/a	1.30	1.28	1.26	1.24	1.22	1.20
Short rural								
Actual	2.2	2.1	2.0	2.0	-	-	-	-
Licence target	n/a	n/a	2.8	2.8	2.8	2.8	2.8	2.8

Source: Integral Energy, *Network Performance Report 2006–07*, p. 57, NSW DRP Licence Conditions.

Consultants review

Wilson Cook considered Integral Energy's reliability improvement capex and concluded proposed expenditure levels are reasonable based on the expected decrease in SAIDI across all feeder types. Further, Wilson Cook noted the development of

[1197] Note that it is actually correct to refer to these as maximum standards as they are expressed in terms of interruptions and minutes off supply, however in this decision they are referred to as minimum standards for the convenience of discussion.

[1198] Integral Energy, *Network Reliability Strategy and reliability works program*, *2008–09*, p. 5.

programs to remedy non-compliant feeders and to address poor-performing areas of the network.[1199]

AER considerations

The AER notes improving reliability performance is a key driver of Integral Energy's capex in the next regulatory control period. With respect to its urban SAIDI, Integral Energy anticipates a reliability improvement of 15 per cent to 80 minutes by the end of the 2009 regulatory control period. The AER further notes Integral Energy has set a 'stretch' reliability target of 75 minutes for the same period, a 20 per cent improvement on current levels.[1200]

The AER notes the vast majority of Integral Energy's feeders are performing better than average levels required and acknowledges variations in the performance of poor-performing feeders is not sufficient enough to result in average feeder performance to fall below the required standard. The AER further notes Integral Energy is expecting to achieve 100 per cent compliance with schedule 2 of the NSW DRP licence conditions for all years within the next regulatory control period.[1201]

The AER has reviewed documentation provided by Integral Energy, including its Network Reliability Strategy and Reliability Works Program, designed to achieve mandatory feeder reliability performance levels. The AER is satisfied Integral Energy's documentation outlines efficient strategies and objectives to target 100 per cent compliance, 100 per cent of the time. Together with advice provided by Wilson Cook, the AER is satisfied that the reliability improvement capex proposed by Integral Energy reasonably reflects efficient costs of achieving the capex objectives under clause 6.5.7(2).

M.5.4.4 Statutory obligations, environmental and safety capex

Integral proposal

Integral Energy proposed $403 million expenditure in this category, which accounts for approximately 14 per cent of its total proposed capex program. This category largely reflects network elements which currently, and are forecast, to require investment to meet the NSW DRP licence conditions leading up to 2013–2014. Table M.9 outlines forecast capex required for compliance.

Integral Energy noted the licence conditions pose a significant requirement for network augmentation. Integral Energy identified the network elements that currently require or are forecast to require investment in the next regulatory control period to comply with the licence conditions include nine transmission substations, 43 sub–transmission feeders, 27 zone substations and 478 distribution feeders.[1202]

[1199] Wilson Cook, volume 3, p. 26.
[1200] Integral Energy, *Regulatory proposal*, p. 76.
[1201] Integral Energy, email to AER, 1 October 2008.
[1202] Integral Energy, *Regulatory proposal*, p. 117.

Table M.9: Forecast compliance capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Sub-transmission substations	22.1	13.3	6.1	2.5	0.6	44.7
Sub-transmission lines	1.4	3.5	3.1	0.0	0.0	7.9
Zone substations	92.7	77.5	31.9	25.9	0.0	228.0
Distribution feeders	12.7	15.7	39.9	21.8	20.9	111.2
Other compliance	2.2	2.2	2.2	2.2	2.2	11.1
Total compliance capex	131.1	112.2	83.3	52.5	23.9	402.9

Source: Integral Energy, regulatory proposal, p. 118.
Note: Totals may not add due to rounding

Integral noted a cost classification distinction has been made between works required to achieve and maintain compliance. Namely, expenditure to upgrade locations assessed as requiring investment as at 1 July 2008 is classified as environmental, safety and statutory obligations compliance expenditure. Locations forecast to require investment post 1 July 2008 are classified elsewhere according to the underlying cause of non-compliance, generally growth, reliability and quality of supply.[1203]

Consultant review

In reviewing Integral Energy's statutory obligation capex, Wilson Cook reviewed Integral Energy's regulatory information notice (RIN) template and network development plans. Wilson Cook noted the proposed capex in this category is predominantly made up of bringing non-compliant parts of the network into compliance with the licence conditions. In reviewing this proposed capex, Wilson Cook followed the same process of review when determining options for network development under the 'growth capex' category. Wilson Cook deemed the proposed expenditure at the transmission, substation and distribution levels as reasonable. Wilson Cook further noted 3 per cent of this proposed expenditure was for a small-scale trial interval meter rollout and environmental enhancement works. After consideration, Wilson Cook accepted the proposed expenditure under this category as reasonable.[1204]

AER considerations

The AER notes that Integral Energy's forecast environmental, safety and statutory compliance forecast capex is approximately two-thirds higher than the equivalent capex incurred expenditure in the current regulatory control period and that the forecast capex is driven primarily by meeting compliance of the NSW DRP Licence Conditions which impose a significant requirement for network augmentation. The AER recognises this expenditure is required to comply with NSW Government regulatory obligations, relating to the reliability and security of supply which is prima

[1203] Integral Energy, *Regulatory proposal*, pp. 117–118.
[1204] Wilson Cook, volume 3, pp. 25–26.

facie consistent with achieving the capex objectives set out in clauses 6.5.7(2) and 6.5.7(4).

The AER has reviewed Integral Energy's proposed capex for this category and it's Strategic Asset Management Plan, in addition to the application of processes in assessing network locations against Licence Conditions criteria. The AER is satisfied Integral Energy's approach reflects good industry practice. Together with advice provided by Wilson Cook and is satisfied that capex proposed under this category reasonably reflects the efficient costs that a prudent operator in the circumstances for Integral Energy would require to meet the capex objectives.

M.5.4.5 Non–system capex

Integral Energy's proposal

Integral Energy proposed non–system capex of $336 million ($2008–09) in the next regulatory control period, a decrease of 8 per cent from the current period. Integral Energy's proposed non–system expenditure is outlined in table M.10. Non–system expenditure accounts for approximately 11 per cent of its total proposed capex.

Table M.10: Integral Energy's proposed non–system capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
ICT	22.2	23.2	23.6	19.1	19.1	107.1
Motor Vehicles	24.7	23.3	25.1	22.8	21.8	117.7
Land and Buildings	19.1	19.0	16.4	14.1	9.2	77.8
Furniture, Fittings, Plant and Equipment	6.8	6.7	6.7	6.7	6.7	33.5
Total Non–system Assets	72.8	72.1	71.8	62.6	56.7	336.1

Source: Integral Energy regulatory proposal, p 119.
NB: Totals may not add due to rounding

The proposed capex for information and communications technology (ICT) is greater than expenditure in the current period, while land and buildings expenditure is forecast to be lower. Non–system capex proposed for motor vehicles, furniture, fittings, plant and equipment is projected to be similar to expenditure in the current regulatory control period.[1205]

Integral Energy commissioned KPMG to review its Network ICT Investment Plan for the next regulatory control period. KPMG found Integral Energy's investment agenda and programs to parallel many of its industry peers.[1206]

Integral Energy commissioned PB to review its forecast fleet and land and buildings expenditure. PB considered the estimation methods for additional vehicle

[1205] Integral Energy, RIN.
[1206] KPMG, *Report on Network ICT Investment Plan for the 2009 Network Determination*, May 2008. p. 2–3.

requirements and Integral Energy's vehicle renewal policy reasonable. Further, PB concluded the bottom up estimation approach utilised by Integral Energy in its forecast for land and buildings capex is reasonable.[1207]

Consultant review

Wilson Cook compared Integral Energy's average non–system capex on a 'cost-per-customer' and 'cost-per-size' against the other ACT and NSW DNSPs forecasts and the regulatory allowances of Ergon and Energex from the 2005 Queensland network determination.[1208] Wilson Cook considers 'cost-per-size' the best benchmark as it takes into account the main parameters which drive non–system capex. Wilson Cook found Integral Energy's non–system capex to fall in the middle range of the group analysed. From its top-down perspective benchmarking analysis, Wilson Cook concluded Integral Energy's overall level of non–system capex was reasonable.[1209]

Wilson Cook further undertook a bottom-up review of a number of specific expenditure categories and projects within Integral Energy's proposed non–system capex. It reviewed Integral Energy's five-year and annual planning approach by which it develops its proposed IT expenditure, which aligns with its network business priorities. Wilson Cook further reviewed supporting documents provided by Integral Energy for specific IT projects.[1210]

Wilson Cook considered the approach taken by Integral Energy to forecast staffing numbers required to deliver the proposed capex program, which were in turn used to determine vehicle requirements and forecast fleet growth. Wilson Cook noted that Integral Energy's forecast fleet capex comprised mainly of replacement expenditure on its existing fleet, in accordance with its vehicle replacement policies. The fleet capex forecast also included increases to support the delivery of its proposed capital program. Wilson Cook considered the approach taken by Integral Energy to determine its forecast motor vehicle expenditure as appropriate and forecast levels to be reasonable.[1211]

Wilson Cook reviewed land and building capex and noted it is driven by forecast growth in personnel, the delivery of suitable facilities for effective operational requirements and increasing compliance requirements for environmentally sound work practices. Wilson Cook reviewed documentation on Integral Energy's land and buildings expenditure and was provided with details of works initially considered for the next regulatory control period, but have since been deferred. Wilson Cook

1207 PB, *Review*, pp. 31–32.

1208 Size is taken as a composite variable C0.5L0.3D0.2 where C equals the number of consumers, L equals the km of line and D equals the maximum demand, representing the networks by their key characteristics. This measure of size was developed by Ofgem but Wilson Cook has substituted demand for energy throughout in the formula on the ground that demand is a stronger driver of expenditure in a distribution lines business than is energy. Further details of the composite size variable are given in section 3 of volume 1 of Wilson Cook's report.

1209 Wilson Cook, volume 3, p. 31.

1210 Wilson Cook, volume 3, pp. 29–31.

1211 Wilson Cook, volume 3, p. 31.

considered the review undertaken by Integral Energy and concluded that a robust process had been followed and that the proposed expenditure was reasonable.[1212]

Wilson Cook noted that Integral Energy's proposed expenditure on furniture, fittings, plant and equipment was slightly less than that in the current regulatory control period. Based on the historical trend Wilson Cook considered the proposed capex reasonable.[1213]

Based on its top-down and bottom-up reviews, Wilson Cook concluded no adjustments were required for Integral Energy's proposed non–system capex.[1214]

AER considerations

The AER has considered the documentation in support of Integral Energy's non–system capex and was involved in discussions on this expenditure between Integral Energy and Wilson Cook.

The AER considers that Wilson Cook's benchmarking of non–system capex has been effective in providing a general reasonableness check of the size of expenditures proposed. In this regard, its review of project documentation in a 'bottom up' sense has been effectively used to validate its findings from a top down perspective.

The AER considered Integral Energy's non–system capex trend and is satisfied proposed non–system capex does not diverge from previous expenditure trends.

The AER considered PB's review of Integral Energy's assumptions underpinning its capex. The AER considered the impact of forecast staff increases on Integral Energy's non–system capex and its link to the volume of capital works forecast for the next regulatory control period.

On the basis of these considerations, and the advice provided by Wilson Cook, the AER considers that the non–system capex reasonably reflects the efficient costs a prudent operator in the circumstances of Integral Energy, is required to achieve the capex objectives.

M.5.5 Deliverability of capex proposal

Integral Energy proposal

Integral Energy's proposed capital program represents a significant increase in expenditure (i.e. 50 per cent) on expenditure in the current regulatory period.[1215]

Integral Energy recognised the concerns of its stakeholders about the deliverability of its capex program. Integral Energy implemented a workforce plan to ensure sufficient labour resources are available to deliver its proposed capex program. Integral Energy

[1212] Wilson Cook, volume 3, p. 31.
[1213] Wilson Cook, volume 3, p. 31.
[1214] Wilson Cook, volume 3, p. 31.
[1215] Integral Energy, RIN.

also noted increases in labour requirements were not significant relative to the entire capex program, given the increased volume of its high cost assets.[1216]

During the current regulatory control period, Integral Energy implemented (or has commenced implementing) a range of initiatives to ensure the capital program is delivered in an efficient and sustainable manner, including:[1217]

- design standardisation
- supply chain management
- alternative delivery models
- increased internal staffing.

Based on its history of successfully delivering an increased capex program, Integral stated it is confident it will deliver its proposed capital program for the next regulatory control period.[1218]

Integral Energy commissioned PB to review its proposed delivery strategy for its capex programs for the 2009 regulatory period. PB recommended Integral Energy prepare a single document which incorporates all its strategies and initiatives outlined in separate documents. PB concluded Integral Energy's delivery strategy appears reasonable and achievable.[1219]

Consultant review

Wilson Cook reviewed Integral Energy's delivery strategy and noted it includes design standardisation, the management of its work program and supply contracts, continued use of a mix of internal and external resources and increased internal staffing, including more apprenticeships. Wilson Cook considered there were no reasons to conclude that the necessary resources could not be mobilised to implement the program. It concluded that Integral Energy put forward a reasonable implementation strategy.[1220]

AER considerations

The AER notes Integral Energy's forecast capex program for the next regulatory control period represents a substantial increase from that of the current regulatory control period. In annual terms, the average proposed expenditure allowance of $591 million ($2008–09) is, however, of a similar magnitude to the $535 million expected to be spent in 2008–09. Taking account of the build up in Integral Energy's project delivery in 2008–09, the AER considers that Integral Energy should have many of its deliverability strategies for the next regulatory control period already in place to deliver on such a significant increase in its capex. Furthermore, when comparing the dollar amounts of expenditures incurred in the current period and those forecast for

[1216] Integral Energy, *Regulatory proposal*, p. 90.
[1217] Integral Energy, *Regulatory proposal*, pp.90–91.
[1218] Integral Energy, *Regulatory proposal*, p. 12.
[1219] PB, *Review*, p. 29.
[1220] Wilson Cook, volume 3, pp. 26–27.

the next period, a proportion of the proposed capex program will reflect the impact of expected increases in real costs rather than physical investment effort.

The AER notes significant analysis undertaken by Integral Energy on the timing of individual projects to achieve an even labour requirement over the next regulatory control period. The AER notes Integral Energy has rearranged projects for later in the regulatory control period to enable a consistent approach in maintaining a sustainable long term capital program.[1221]

Although the strategies proposed by Integral Energy appear reasonable as noted by Wilson Cook, the AER does have some concerns that the DNSPs will be seeking the same resources concurrently using overlapping delivery strategies, including with TransGrid. In conjunction with this, Integral Energy may face financing constraints due to the rising cost of debt should the current credit crisis persist.[1222]. Further physical resource constraints are also likely to be addressed, to some extent, by an expectation that the Australian economy is entering a period of reduced activity which will see a decline in demand for resources from other sectors of the economy.

Given concerns about the concurrent levels of investment proposed for the broader NSW electricity network, the AER will carefully monitor the expenditures of Integral Energy. The AER through its annual regulatory reports will publicly publish the actual capex spend by Integral Energy, including any under or over spends if they occur.

Based on its own review of Integral Energy's workforce plan, and the advice of Wilson Cook, the AER considers the deliverability of Integral Energy's forecast capex program is consistent with the capex objectives generally, and in so far as this aspect is concerned is satisfied it reasonably reflects the criteria.

M.6 AER conclusion

The AER has reviewed Integral Energy's proposed forecast capex allowance and, for the reasons set out in this appendix, the AER is not satisfied that the proposed forecast capital allowance of Integral Energy reasonably reflects the capex criteria under clause 6.5.7(c). In reaching this conclusion, the AER has regarded the capex factors set out in 6.5.7(e). In particular, the AER considers:

- Integral Energy's application of replacement capex does not reasonably reflect the efficient costs required to achieve the capex objectives, especially that associated with other substation renewal projects, the unspecified civil works and the unspecified work on the sub–transmission mains

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[1221] Integral Energy, *Regulatory proposal*, p. 90.

[1222] The AER notes that the NSW Government's Mini Budget 2008–09 provides for an $857 million reduction over three years in the borrowing capacity of the NSW DNSPs and TransGrid. The AER has assessed this financing constraint against the proposed capex programs from 2009–10 to 2011–12, and is satisfied that this need not adversely impact on the deliverability of the program. The reduction in the borrowing program represents a relatively small proportion of the capex program and its impact may be offset by increased internal efficiencies in each of the businesses and or by a change in the timing of dividend payments to the to the shareholder. See: <http://www.treasury.nsw.gov.au/__data/assets/pdf_file/0016/12706/08–09_Mini-Budget.pdf>

- The expenditure associated with Integral Energy's application of its proposal input cost escalators do not reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives and has accordingly proposed amended real input cost escalators

As the AER is not satisfied that the proposed capex allowance reasonably reflects the capex criteria, under clause 6.5.7(d) the AER must not accept the forecast capex proposed by Integral Energy. Under clause 6.12.1(3)(ii), the AER is therefore required to provide an estimate of the capex for each DNSP over the next regulatory control period it is satisfied reasonably reflects the capex criteria, taking into account the capex factors. To this end, the AER proposes the following adjustments to Integral Energy's proposed forecast capex as set out in table M.11.

These adjustments result in an estimate of forecast capex of $2913.7 million. The AER is satisfied this estimate will reasonably reflect the capex criteria in clause 6.5.7(c), being the efficient costs that a prudent operator in the circumstances of Integral Energy would required, and is a realistic expectation of the demand forecast and cost inputs required, to achieve the capex objectives at clause 6.5.7(a).

Table M.11: AER decision - Integral Energy capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Integral Energy proposal	573.9	641.5	610.4	582.5	544.3	2952.7
AER adjustments arising from replacement capex	–	–2.1	–3.1	–4.4	–20.1	–29.8
AER adjustments arising from real cost escalators[a]	–2.0	–1.4	–1.0	–2.5	–2.4	–9.3
AER approved capex allowance	571.9	638.0	606.3	575.5	521.9	2913.7

a Note: includes impact of revised inflation on 2007–08 base capex
Note: Totals may not add due to rounding

Appendix N: Cost escalators

N.1 Introduction

In recent decisions for electricity TNSPs (including Powerlink, SP AusNet and ElectraNet) the AER has allowed capex and/or opex allowances to be escalated in real terms for input cost increases.[1223] This involves the disaggregation of expenditure allowances into specific inputs (e.g. labour, land and materials) which are priced in terms of a base year. These base year costs are increased or decreased for each year of the regulatory control period relative to changes in the nominal price level, which is taken into account when prices and revenues are adjusted at the aggregated level under the CPI–X control mechanism.

The methodology employed to determine the cost escalators generally combines independent forecast movements in the price of input components with 'weightings' for the relative contribution of each of the components to final equipment/project costs. This in turn generates real capex and opex forecasts for the regulatory control period. The weightings are typically specific to each regulated business given differences in composition of their respective expenditure forecasts.

The underlying objective of real cost escalations was to take account of the commodities boom and skills shortages in the engineering field in Australia. In light of these external factors, it was considered that cost escalation at CPI no longer reasonably reflected a realistic expectation of the movement in some of the equipment and labour costs faced by electricity network service providers (NSPs).[1224] It was also communicated by the AER at the time of allowing real cost escalations that the regime should symmetrically allow for real cost decreases.[1225] This was to allow end-users to receive the benefit of real cost reductions as well as facing the cost of real increases.

Given that there is no futures market for the procurement and installation of electrical equipment (e.g. transformers, switchgear), in previous decisions cost escalations have been estimated with reference to the expected growth in key input 'cost factors' such as:

- copper
- aluminium
- crude oil

[1223] AER, *Powerlink revenue cap decision*, pp. 60–70;
AER, *Draft Decision – SP AusNet transmission determination 2008–09 to 2013-14*, 31 August 2007, pp. 87–91, 316–331;
AER, *Final Decision – ElectraNet transmission determination 2008–09 to 2012-13*, 11 April 2008, pp. 29–48.

[1224] Transitional chapter 6 rules, clause 6.5.7(c)(3).

[1225] AER, *Final Decision – SP AusNet transmission determination 2008–09 to 2013-14*, January 2008, p. 80.

- construction costs
- electricity, gas and water (EGW) sector labour costs
- land/easement costs
- other inputs (such as steel) were escalated at CPI.

During its revenue reset process, ElectraNet engaged the Competition Economists Group (CEG) to develop forecasts for each of the cost factors and used them to escalate its proposed capex program. In its final decision, the AER accepted its consultant Sinclair Knight Merz's (SKM) recommendation that CEG's proposed real cost escalators for materials are reasonable, subject to a number of adjustments.[1226] In particular the AER accepted SKM's recommendations that:

- London Metal Exchange (LME) forward contract prices (i.e. 27 months) provide the best estimate of the price of aluminium and copper for a relevant future date
- monthly average futures prices should be used rather than a single day price
- Consensus Economics' 5−10 year forecasts for aluminium and copper prices represent the best available long-term forecast
- CEG's proposed adjustment to the long-term Consensus Economics aluminium and copper forecasts to reflect the higher LME futures forecast prices is not reasonable
- for the purposes of interpolation, Consensus Economics' 5−10 year forecast for aluminium and copper prices should be interpreted as the mid-point of 7.5 years, rather than 10 years as proposed by CEG.[1227]

The AER has been mindful of the arguments presented and conclusions reached in its determination for ElectraNet when assessing the NSW DNSPs' proposals. This appendix presents the AER's assessment of the methodology and data sources for the proposed escalators. Where possible, the values of the escalators presented here will be updated at the time of the AER's final decision and determination.

N.2 Current proposal

As part of their regulatory proposals, the NSW DNSPs engaged CEG to develop real cost escalation forecasts for the next regulatory control period.[1228] For the most part CEG has maintained its methodology used to forecast aluminium, copper, crude oil prices and construction costs based on the report it prepared for ElectraNet, including

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[1226] AER, *Final Decision – ElectraNet transmission determination*, pp. 29–48.

[1227] Consensus Economics is an international economic survey organisation. See: http://www.consensuseconomics.com/.

[1228] CEG, *Escalation factors affecting expenditure forecasts: a report for NSW electricity businesses*, April 2008.

its proposed adjustments to the Consensus Economics aluminium and copper price forecasts.

The AER considers that its conclusions from the recent ElectraNet decision are still applicable with respect to the methodology used for estimating each of these cost factors (i.e. copper, aluminium and crude oil). In most cases, CEG has not presented any new compelling evidence justifying a departure from the approach previously accepted by the AER. The AER has also calculated forecasts for this draft decision using the latest available data, and intends to update this data for its final decision.

In its latest report CEG has proposed a number of additional cost factors not previously applied to the overall cost escalation methodology, including:[1229]

- variances in prices charged by equipment manufacturers to reflect their market power (producer margins)
- the proportion of general labour costs used in the manufacture of electrical equipment (producer labour costs)
- indirect general labour costs associated with the processing of raw materials (e.g. steel).

The AER has concerns that these additional cost factors represent a departure from the AER's intention to account for the effects of the recent commodities boom and skilled labour shortages in Australia. The effect of their addition would be to offset the expected declines in commodities prices and the symmetry of the cost escalators envisaged by the AER and set out in its decision for SP AusNet.[1230] Moreover, they represent a move towards compensation for all input costs at a fine level of detail and go beyond the AER's general obligation to provide businesses a reasonable opportunity to recover efficient costs, and in this sense are also inconsistent with the incentive frameworks for capex and opex.

Notwithstanding these general concerns, the AER also considers that these additional proposed real cost factors do not meet the underlying objective for inclusion in forecast costs under clause 6.5.7(c) of the transitional chapter 6 rules. Specifically, given the inherent uncertainties around the existence of and estimation of real movements in these cost factors, the AER does not consider that further departures from CPI are warranted. It is important to note that the AER accepts that such costs are likely to be included in base (unit) cost estimates. However, what is questionable is the extent to which real growth is expected and whether it can be forecast on a reasonable basis.

This appendix presents the AER's assessment of the methodology and data sources for the proposed escalators. Where possible, the values of the escalators presented here will be updated at the time of the AER's final decision and determination.

[1229] CEG, *NSW electricity businesses*, pp. 27–38.
[1230] AER, *Final Decision – SP AusNet transmission determination,* p. X.

N.3 Labour cost escalators

This section discusses the real labour cost escalations proposed by the NSW DNSPs to apply to their forecast capex and opex allowances over the next regulatory control period. The proposed labour cost escalators fall into two categories:

- electricity, gas and water (EGW) or utility sector-specific labour cost forecasts
- general labour cost forecasts.

These two categories of labour costs are discussed separately below.

N.3.1 Electricity, gas and water (EGW) sector labour escalators

N.3.1.1 CEG/NSW DNSPs

The NSW DNSPs obtained advice from CEG on forecast annual labour escalation rates for the EGW sector.[1231]

CEG relied on forecasts produced by Macromonitor and Econtech to derive its labour escalators for the EGW or utility sectors in NSW. The labour cost escalators from Macromonitor and Econtech are shown in table N.1.

Table N.1: CEG's real labour cost growth rates for the EGW sector (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Macromonitor (NSW)[a]	4.2	4.4	2.3	–1.2	1.7	3.7	4.2
Econtech (AUS)	2.0	2.8	5.6	5.0	3.9	3.4	3.1

Source: CEG, NSW electricity businesses, April 2008, p. 7.
(a) Productivity adjusted.

The Econtech national forecasts used by CEG are based on a report to the AER for the SP AusNet and VENCorp revenue resets.[1232]

The report by Macromonitor was commissioned by TransGrid, Transend and the NSW DNSPs. The Macromonitor report calculates productivity adjusted or unit labour costs for the EGW sectors in NSW and Tasmania.[1233]

Macromonitor noted that the actual labour cost involved with undertaking a given amount of activity is not purely determined by the rate of wages per hour, but also by the number of hours work required. Macromonitor stated that in examining the changes in an organisation's labour costs over time, a more meaningful measure than nominal wages is labour cost per unit of output, or per unit of activity. The change in

[1231] CEG, *NSW electricity businesses*, April 2008.
[1232] Econtech, *Labour cost growth forecasts*, attachment D, 13 August 2007.
[1233] Macromonitor, *Forecasts of cost indicators for the electricity transmission sector, New South Wales & Tasmania*, February 2008.

this measure over time reflects both changes in wages and changes in labour productivity.[1234]

Macromonitor has forecast annual productivity declines in the utility sector over the next few years which become positive from 2011–12. Between 2007–08 and 2013–14, Macromonitor has forecast an average annual productivity reduction of 0.7 per cent in the NSW EGW sector.[1235] Macromonitor attributes the decline in productivity to a continuing upturn in the economy, together with a tight labour market and difficulties in attracting and retaining skilled staff.

CEG deflated Macromonitor's nominal labour cost escalators using its estimate of CPI to obtain the real escalators.[1236] CEG also calculated real unit labour costs by using Macromonitor's forecast average annual change in productivity growth for the period, rather than individual forecasts for each year. CEG derived real unit labour costs by subtracting average productivity growth from growth in real wages.[1237]

CEG recommended that averaging the escalation rates calculated by Econtech and Macromonitor provides an appropriate forecast of labour cost escalators for the EGW sector in NSW. CEG did not provide any justification for averaging data from the two sources. The labour cost escalators recommended by CEG are shown in table N.2.

Table N.2: CEG's real wage growth for the EGW sectors in Tasmania and NSW (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Tasmania	2.2	3.2	4.0	2.7	3.1	3.9	4.0
NSW	3.1	3.60	3.9	1.90	2.80	3.5	3.7

Source: CEG, *NSW electricity businesses*, April 2008, p. 8;
CEG, *Transend*, April 2008, p. 8.

N.3.1.2 Econtech

The AER engaged Econtech to provide advice on wage forecasts for the EGW sectors in NSW, ACT and Tasmania.[1238] Econtech's labour cost growth rates for these sectors in NSW, Tasmania, the ACT and nationally are shown in table N.3.

[1234] Macromonitor, p. 8.
[1235] CEG, *NSW electricity businesses*, April 2008, p. 10.
[1236] CEG use its own CPI forecasts to deflate Macromonitor's labour cost forecast.
[1237] CEG, *NSW electricity businesses*, April 2008, p. 10.
[1238] Econtech, *Labour cost growth forecasts*. Econtech is an economic consulting firm that specialises in economic modelling, forecasting and policy analysis. Econtech merged with KPMG in August 2008.

Table N.3: Econtech's real labour escalation rates for the EGW sector (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
NSW	1.2	2.8	3.9	3.4	3.0	2.8	2.1
Tasmania	–3.0	2.0	2.9	2.8	2.5	2.4	1.9
ACT	9.4	2.0	3.7	3.6	3.3	3.1	2.4
Australia	–0.8	2.2	3.3	3.1	2.8	2.6	2.1

Source: Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, 19 September 2008, Appendix D, p. 25 and pp. 10 – 12.

Econtech determined these forecasts using an updated version of the model it developed for its report to the AER in August 2007. In particular, the forecasts provided by Econtech incorporate:[1239]

- a simplified, but enhanced approach to labour cost forecasting
- national accounts data from December 2007 (which was published by the Australian Bureau of Statistics (ABS) in March 2008)
- average weekly earnings data obtained by request from the ABS in August 2008
- policy measures introduced in the 2008–09 federal budget
- an extension of the forecast period from 2015–16 to 2016–17.

These forecasts are broadly consistent with Econtech's national forecasts. Over the next regulatory control period, Econtech has forecast an average growth rate of 2.8 per cent (real) for the NSW utilities sector, 2.3 per cent (real) for the Tasmanian utilities sector and 3.0 per cent (real) for the ACT utilities sector. In comparison, the forecast average growth rate for the utility industry in Australia is 2.6 per cent (real).

Econtech made the following observations on the utility sectors in NSW, Tasmania and the ACT:[1240]

- The forecast annual wage growth for the utility sectors in NSW, Tasmania and the ACT are expected to be higher than the all-industry average over the forecast period.
- The shortage of skilled workers in the utility sectors continues to be a significant driver of labour costs. Electrical and engineering professionals are included in the Department of Education, Employment and Workplace Relations (DEEWR) "Skill Shortage List" for NSW, Tasmania and the ACT.

[1239] Econtech, *Labour cost growth forecasts,* p. 4.
[1240] Econtech, *Labour cost growth forecasts,* p. 4.

- A number of initiatives have been introduced to increase the supply of skilled workers. For example, the Australian Government, through its Skilling Australia Policy, will provide 450,000 new training places over the next four years. However, most of these initiatives represent a long-term solution and are therefore not expected to have a material impact in the short-term.

- The Australian Government has put in place a number of initiatives to lift permanent and temporary migration. Such initiatives have the potential to relieve skills shortages in the short-term, however, there are concerns over the ability of this additional labour to meet industry demand.

- An aging workforce in the utility industry may also put further strain on the supply of skilled labour.

- The fact that electricity, gas and water are essential services means that businesses have a greater imperative to attract and maintain skilled workers, and are more likely to absorb wage increases in order to maintain labour supply.

- The utility industry has had difficulty in retaining skilled staff due to demand booms in related industries. The utility industry employs a large proportion of electricians, electrical and other engineers which are occupations also employed extensively by the construction and mining industries.

Econtech reviewed the methodology used by CEG to forecast labour cost growth rates in the EGW sectors in NSW and Tasmania. Econtech stated that CEG's approach of averaging the Macromonitor and Econtech labour cost forecasts was misguided because these forecasts were not comparable. Averaging the two forecasts is methodologically unsound and likely to provide inappropriate forecasts of labour cost escalation. In particular, Econtech noted:[1241]

- The report prepared by Macromonitor does not contain any description of the methodology used to forecast wages growth, which makes it difficult to evaluate the labour cost growth forecasts produced by Macromonitor. Further, Macromonitor does not use any econometric techniques to derive its forecasts.[1242]

- While reasons were put forward in the Macromonitor report to explain forecasts of productivity, there was no clear methodology provided that outlined how productivity was forecast.

- Unlike the Macromonitor forecasts, the Econtech forecasts of wages growth do not remove productivity growth. Econtech's forecasts of wage growth represent the general increase in labour costs over and above inflation as well as specific compensation to labour for increases in productivity. Since Econtech's forecasts

[1241] Econtech, *Labour cost growth forecasts*, p. 38–42.
[1242] Macromonitor, p. 3.

incorporate compensation for increases in productivity, they are not equivalent to the Macromonitor labour cost forecasts.[1243]

- The 2007 Econtech labour forecasts adopted by CEG are based on the national economy, whereas the Macromonitor forecasts are specific for NSW and Tasmania.

N.3.1.3 AER considerations

The AER has examined the EGW wage growth forecasts put forward by CEG for NSW and Tasmania. Based on Econtech's advice the AER does not consider that the averaging methodology employed by CEG to forecast wages growth in the utility sectors for NSW and Tasmania is sufficiently robust. In particular, the AER notes Econtech's advice that the Macromonitor and Econtech forecasts are not comparable and that averaging the two forecasts is methodologically unsound and likely to provide inappropriate forecasts of labour cost escalation.[1244]

In addition to the inappropriateness of averaging data from Econtech and Macromonitor, the AER does not consider that the CEG proposed labour cost growth rates are a reasonable reflection of the likely future labour costs as they are not based on the most recent information. The AER notes Econtech's advice that since it provided forecasts of labour cost growth rates to the AER in August 2007 (which were used by CEG and SKM), the economic climate has changed considerably, resulting in some pressure being taken off wages growth.[1245] In particular, Econtech stated that:

> Projections of annual labour cost growth rates for overall state and territories have moderated in the past 12 months. The Reserve Bank of Australia (RBA) raised the official cash rate by 25 base points on four separate occasions since August 2007. The extent of the slowdown in household spending and credit expansion from within the household and business sector lead to the RBA to cut interest rates by 25 base points in September 2008. Despite this interest rate cut, the outlook for economic growth remains weak and the unemployment rate is expected to rise over the forecast period. These factors have combined to take some pressure off wages growth at the state and national level, since the last forecasts provided to the AER in 2007.[1246]

The AER also does not consider it appropriate to rely on the forecasts presented by Macromonitor because there is no description of the methodology used to forecast wages growth or productivity.

For these reasons the AER does not consider CEG's proposed labour cost growth rates for the EGW sector in NSW provide reasonable inputs to deriving the efficient

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[1243] Econtech's labour cost model incorporates labour productivity via the employment forecasts used in MM2 (macroeconomic model of the Australian economy). MM2 incorporates labour productivity assumptions through its own labour productivity index, PSkill. PSkill is an input into the model and not an output. MM2 also incorporates assumptions regarding the growth in labour efficiency for each industry. Labour efficiency in each industry is then used to augment PSkill.

[1244] Econtech, *Labour cost growth forecasts,* p. 42.

[1245] Econtech, *Labour cost growth forecasts*, p. 24.

[1246] Econtech, *Labour cost growth forecasts*, p. 24.

costs a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives.

The AER notes that each NSW DNSP operates under a separate Enterprise Bargaining Agreement (EBAs) or Award. The AER requested each DNSP to provide the actual wage increases set out under their respective EBA or Award. The wage increases for 2007–08 are shown in table N.4. The AER notes that given the EBAs or Awards the NSW DNSPs are individually operating under will expire within the next six months or so, the actual wage increases for 2008–09 are generally not available.

Table N.4: Actual wage increases under individual EBAs or Awards for 2007–08 (per cent)

	Country Energy	EnergyAustralia	Integral Energy
Actual wage increase (nominal)	3.0	6.0	6.1
Actual wage increase (real)	–1.4	1.4	1.5

Source: Country Energy response to AER request for information, confidential, 17 September 2008; EnergyAustralia response to AER request for information, confidential, 24 September 2008; EnergyAustralia, Errors of fact and confidentiality on advanced copy of the AER's draft determination, 24 November 2008, p. 11;
Integral Energy response to AER request for information, confidential, 17 September 2008.

Note: The AER derived the real EBA rates by using the actual CPI for 2007–08 of 4.5 per cent.

Given that the actual wage data is available for 2007–08, the AER will apply the actual wage rate provided for under each EBA or Award. From 2008–09 onwards the AER will apply Econtech's NSW labour cost forecasts to the EnergyAustralia, Country Energy and Integral Energy opex and capex proposals.

AER conclusions

The AER's conclusions on EGW growth rates are provided in table 5. On average, the Econtech labour cost growth forecasts are lower than the CEG forecasts for NSW during the next regulatory control period. This is largely because the economic climate has changed considerably since the last Econtech forecasts provided to the AER in 2007, resulting in some pressure being taken off wages growth.

The AER considers that the application of the Econtech forecasts for wages growth in the EGW sector for NSW reflects the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the capex and opex objectives.

Table N.5: AER's conclusion on NSW EGW real labour growth rates (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
AER's EGW labour	−1.4 (CE) 1.4 (EA) 1.5 (IE)	2.8	3.9	3.4	3.0	2.8	2.1	3.0

Source: CEG, NSW electricity businesses, p. 8; Econtech, p. 10.
Note: The AER derived the real growth rates for 2007–08 using the actual CPI for 2007–08 of 4.5 per cent.
The average is calculated for 2009–10 to 2013–14.

N.3.2 General labour escalators

N.3.2.1 CEG

CEG recommended that the NSW DNSPs apply Econtech's forecast for wages across the Australian economy as an appropriate estimate of general labour costs. The general labour cost forecast recommended by CEG is taken from Econtech's Australian National State and Industry Outlook (ANSIO) December 2007 report and is outlined in table N.6.

Table N.6: CEG's real general wage growth (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
General wage	1.8	1.6	2.4	1.9	1.8	2.0	2.0

Source: CEG, *NSW electricity businesses*, April 2008.

EnergyAustralia and Country Energy have applied CEG's recommended general labour escalator to various aspects of their proposed opex and capex proposals, to account for real cost increases for more generic categories of direct labour. For example, EnergyAustralia applied the CEG forecast for general wages to contracted services labour (other than civil construction) related to its capex, to contracted services labour related with its maintenance activities and to labour associated with corporate support as part of its opex.

CEG recommended that the DNSPs apply the Econtech general wage cost to escalate equipment cost inputs (incurred by equipment manufacturers) for the next regulatory control period.[1247] CEG stated that DNSPs could face higher equipment costs due to increased producers wage costs and these indirect labour costs should be recoverable under the AER's regulatory framework.

CEG produced its estimates for producer labour costs using the ABS input-output tables.[1248] These tables examine the supply and use of goods and services in the Australian economy by identifying the inputs (including employee compensation)

[1247] CEG, *Escalation factors affecting expenditure forecasts*, April 2008.
[1248] ABS, *Australian National Accounts: Input-Output Tables 2001/02*, Catalogue Number 5209.0.55.001, Table 2.

used by a particular industry relative to defined outputs. All the data in the ABS input-output tables are specific to the Australian economy.

CEG stated that it has:[1249]

> …estimated the proportion of inputs associated with labour in each relevant industry by calculating the ratio of the compensation of employees against the combined sum of this and the total value of production.

CEG calculated the proportion of labour used to produce each relevant ABS output category to be 27 per cent.[1250] The categories examined were:

- primary plant and materials supply
- secondary systems and materials supply
- transformers
- aluminium conductor
- copper cable/conductor.

CEG then recommended using Econtech's Australian general wage cost forecasts to escalate the labour component of the above equipment categories over the next regulatory control period.[1251]

N.3.2.2 AER considerations—direct labour costs

The AER accepts that a general labour cost forecast is appropriate to escalate general direct labour costs (i.e. other than EGW) incurred by the DNSPs.

As part of its report to the AER, Econtech also provided advice on general wage forecasts for all industries across Australia. A comparison of Econtech's general wage forecast with the forecasts recommend by CEG is shown in table N.7.

Table N.7: CEG and Econtech's real labour escalators for general wages (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
CEG	1.8	1.6	2.4	1.9	1.8	2.0	2.0	2.02
Econtech	0.6	1.0	1.1	0.7	0.7	0.8	0.6	0.78

Source: CEG, *NSW electricity businesses*, p. 31;
Econtech, *Labour cost growth forecasts*, p. 25.
Note: The average is calculated for 2009–10 to 2013–14.

As can be seen from table N.7 there is a material difference between the general wage forecasts provided by CEG and Econtech's general wage forecasts.

1249 CEG, *NSW electricity businesses*, p. 30.
1250 CEG, *NSW electricity businesses*, p. 31.
1251 CEG, *NSW electricity businesses*, p. 31.

The AER notes that the general wage forecasts used by CEG were taken from Econtech reports published in 2007. Econtech stated that, since it provided forecasts of labour cost growth rates to the AER in August 2007, the economic climate has changed considerably.[1252]

The AER notes that Econtech's latest ANSIO for June 2008 also predicts a decline in average earnings for general wages.

Given the change in economic conditions since 2007, the AER does not consider that the general wage forecasts proposed by CEG are reasonable for the purposes of forecasting efficient input costs for the next regulatory control period required to meet the capex and opex objectives of the transitional chapter 6 rules.

Accordingly, where applicable the AER will apply Econtech's latest general wage forecasts to the NSW DNSPs' capex and opex proposals.

N.3.2.3 AER conclusions—direct labour costs

The AER's conclusion on a general labour cost escalator is set out in table N.8.

Table N.8: AER's conclusion on real general wage growth (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
AER	0.6	1.0	1.1	0.7	0.7	0.8	0.6	0.8

Source: Econtech, *Labour cost growth forecasts*, p. 25.

N.3.2.4 AER considerations—indirect labour costs

The AER notes that EnergyAustralia and Country Energy have applied the Econtech labour cost escalator to equipment cost inputs. This is intended to represent the labour costs incurred by the producers of manufactured equipment that is purchased by NSPs.

The AER notes CEG's proposal to weight general labour costs at 27 per cent of the total costs of various electrical equipment. As noted in section N.2, the AER considers that the introduction of a new labour component in equipment costs is inappropriate as it:

- represents a movement beyond the AER's obligation to provide regulated businesses a reasonable opportunity to recover efficient costs towards providing compensation for changes in input costs at a very fine level of detail. The AER considers it sufficient to monitor whether the cost of finished goods, as opposed to the component parts, need to be escalated above or below CPI
- is not supported by robust data.

The AER notes that some amount of producers' labour costs will already be embedded in the NSPs' base cost estimates of equipment (i.e. as at 30 June 2007). However, what is questionable is the extent to which the existing producers' labour

[1252] Econtech, *Labour cost growth forecasts*, p. 5.

costs embedded in base costs are expected to change in real terms over the next regulatory control period, and if a real change is expected, how to reliably measure it.

The data used by CEG assumes that Australian manufacturing conditions (as measured in the ABS input-output tables) and wage growth rates are the same as in those countries where equipment is purchased from. It also assumes that labour and other factor productivity is held constant. These issues have not been addressed by CEG to substantiate its recommended position.

N.3.2.5 AER conclusions—indirect labour costs

The AER does not accept the producer wage cost escalator proposed by CEG as it does not meet the underlying objective for inclusion in forecast costs under clause 6.5.7(c) of the transitional chapter 6 rules. On the basis of the information presented, the AER is not satisfied that expenditure associated with a real escalation of indirect labour costs is required to meet the capex and opex objectives.

N.4 Land/easement cost escalators

This section discusses the real land/easement cost escalations proposed by the NSW DNSPs to apply to their forecast expenditure proposals over the next regulatory control period.

N.4.1 Proposals

The NSW DNSPs obtained advice from CEG on forecast movements for land prices in NSW.[1253] CEG based its average real annual escalation forecasts on estimates supplied by BIS Shrapnel.[1254] CEG forecast 4.1 per cent per annum for both Sydney CBD B Grade and non-CBD B Grade properties.[1255]

CEG noted the difficulty in predicting annual changes in real estate growth, given the variability with investors' perceptions of expected growth in rental prices. Further, CEG noted the difficulty in forecasting real estate growth over widespread areas in which the NSW DNSPs operate.

N.4.2 AER considerations

The AER notes that CEG did not outline a transparent methodology to derive its average land value escalators. Further, CEG's recommended average annual land escalators for Sydney CBD B Grade and non-CBD B Grade property of 4.1 per cent (in real terms) is based on nominal estimates provided by BIS Shrapnel. The BIS Shrapnel report did not provide a clear methodology that it used to derive estimates and did not include non-CBD B Grade property data.

1253 CEG, *NSW electricity businesses*.

1254 BIS Shrapnel, *Sydney Commercial Property Prospects 2007 – 2021*, May 2007.

1255 CEG, *NSW electricity businesses*, p. 1. B Grade property refers to non-price property, eg, land not typically suited for retail or office development; Non-CBD B Grade property is based on the average forecast for North Sydney, Chatswood, Parramatta and North Ryde.

In previous transmission determinations, the AER utilised ABS long-term historical land data to develop forecast proxies for land and easement escalation rates.[1256] The AER considers the use of a long-term historical average as a reasonable forecast due to long-term data being less exposed to business cycle fluctuations. Therefore, to test the appropriateness of the forecast land escalators proposed by CEG, the AER considered NSW land value data published by the ABS, using its entire data series (1989–2007).[1257] The AER derived an equal weighted average rate based on NSW land types published by the ABS (residential, commercial and rural), deflated by CPI to calculate a real growth rate that is generally consistent with that recommended by CEG.

Based on the long-term historical trends of land value growth published by the ABS, the AER considers that the proposed average land/easement escalator of 4.1 per cent provides a reasonable measure of forecast real land value growth expected in NSW.

N.4.2.1 AER conclusions

The AER's conclusions on the real land escalators for NSW are set out in table N.10.

Table N.10: AER's conclusion on real land escalators for NSW (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Land	4.1	4.1	4.1	4.1	4.1	4.1	4.1

N.5 Materials cost escalators

This section discusses the real materials cost escalators proposed by the NSW DNSPs to apply to their forecast capex and/or opex allowances over the next regulatory control period. The proposed materials cost escalators are as follows:

- copper and aluminium
- steel
- crude oil
- exchange rates (used to develop the materials cost escalators)
- producer margins
- construction costs (includes labour and materials costs).

These cost escalators are discussed below.

1256 AER, *Powerlink Draft Determination*, 8 December 2006, p. 76;
AER, *SP AusNet Draft Determination*, 31 August 2007, pp. 189–190;
AER, *ElectraNet Final Decision*, 11 April 2008, p. 34.

1257 ABS, *Australian System of National Accounts, 2006-07,* ABS Cat No. 5204.0, Table 83.

N.5.1 Aluminium and copper

N.5.1.1 ElectraNet transmission determination

Following the AER's draft decision which rejected ElectraNet's non-labour (materials) cost escalators, ElectraNet engaged CEG to develop forecast materials cost escalators for its capex program.

In determining escalators for aluminium and copper CEG used London Metal Exchange (LME) actual and futures prices of these base metals for the period up to June 2009. From this point CEG determined forecasts through a straight-line interpolation between the latest available LME forecast and Consensus Economics' long-term forecast. The Consensus Economics' long-term forecast used in this calculation was adjusted by CEG to reflect the difference between the forecast for April 2010 (as implied by the 27-month LME futures price as at January 2008) and the mean Consensus Economics forecast for March 2010—an approach CEG considered to be consistent with the view that futures prices provides the most reliable forecasts of metals prices.[1258]

SKM, in its final report for the AER, commented that applying an upward adjustment to Consensus Economics' long-term forecasts detracts from the economic assumptions made by forecasters and that they would have considered the latest market information (such as LME forward contracts) in their forecasts.[1259] SKM consequently recommended that the upward adjustments be removed from the calculation of escalators for aluminium and copper.

In its final decision the AER accepted SKM's recommendation to not adjust Consensus Economics' long-term aluminium and copper price forecasts. It also accepted SKM's recommendations that:

- LME forward contract prices provide the best estimate of the price of aluminium and copper for a relevant future date
- a monthly average futures price be used rather than the single day futures price
- the interpolation of the Consensus Economics' long-term price forecast should be to the mid-point of 7.5 years, rather than 10 years.

For further discussion of these issues see chapter 3 of the AER's final decision for ElectraNet.[1260]

N.5.1.2 CEG/NSW DNSPs

The NSW DNSPs engaged CEG to develop aluminium and copper cost escalators. CEG used two data sources to develop its aluminium and copper price forecasts:

[1258] In this case, CEG adjusted Consensus Economics' long-term forecasts for aluminium and copper by 9 per cent and 18 per cent respectively.

[1259] SKM, *ElectraNet Transmission Network Revised Revenue Proposal 2008-2013*, 24 April 2008.

[1260] AER, *Final Decision, ElectraNet Transmission Determination*.

- LME actual prices to March 2008, then forward contracts (3, 15 and 27 months) for short-term price forecasts out to June 2010
- Consensus Economics long-term price forecasts from July 2010 to 2017.

The Consensus Economics report provides a single mean price forecast of long-term aluminium and copper prices (among other commodities), which it developed from a survey of over 20 commodity price forecasters. As with the report it prepared for ElectraNet, for the purposes of data interpolation, CEG has defined the 'long-term' to be 10 years, being the end point of the 5 to 10 year period defined as 'long-term' by Consensus Economics.

To merge the LME forward contract price forecasts with Consensus Economics' long-term forecasts, CEG interpolated the LME forecasts as at June 2010 with an adjusted Consensus Economics' long-term forecast. As with the report it prepared for ElectraNet, CEG observed that the Consensus Economics' forecasts were lower than the LME 27-month forward contract price in the period out to June 2010 by an average of 21 per cent and 30 per cent for aluminium and copper respectively. Subsequently, CEG scaled up Consensus Economics' long-term forecast by these percentage differences.[1261]

CEG's proposed real copper and aluminium cost escalators for the 2007–14 period are presented in table N.11.

Table N.11: CEG's proposed real cost escalators for copper and aluminium (per cent)

	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
Copper	–0.4	–3.7	–6.3	–4.2	–2.8	–3.1	–3.1
Aluminium	–5.6	3.5	–0.5	–0.2	0.3	0.0	0.0

Source: CEG, *NSW electricity businesses*, p. 1.

N.5.1.3 AER considerations

The AER considers that a linear interpolation between the LME forecasts and the Consensus Economics' long-term forecast appears to be the most reasonable approach to merge the short-term LME data with Consensus Economics long-term forecasts. The AER does not, however, consider that an upward adjustment (21 per cent and 30 per cent for aluminium and copper respectively) to Consensus Economics' data prior to interpolation is appropriate. Interpolation between these two data sources, without adjustment of Consensus data, is the same methodology approved by the AER in its determination for ElectraNet. The AER considers this methodology provides reasonable estimates of efficient cost inputs that the NSW DNSPs require to achieve their capex and opex objectives under the transitional chapter 6 rules.

In the ElectraNet revenue reset process, the AER engaged SKM to review and provide advice on CEG's methodology. SKM provided a number of reasons why Consensus

[1261] CEG, *NSW electricity businesses*, pp. 17–18.

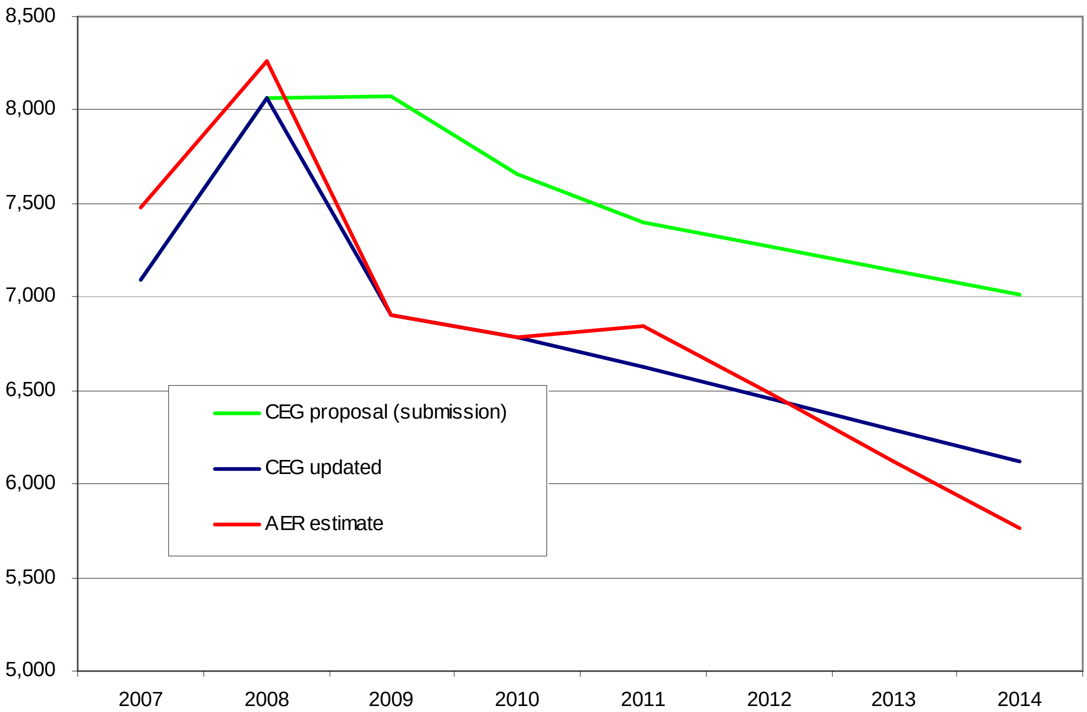
Economics' long-term forecasts should not be adjusted in accordance with the CEG proposal:

> … the assumption that the experienced forecasters developing the various predictions that constitute the long-term Consensus Economics prices, would be well aware of 27 month LME prices, and principles of linear interpolation, yet still chose to predict long-term prices at the levels presented.
>
> … CEG's adjustment, based on the difference between the LME 27 month contract price and the corresponding Consensus Forecast of the spot price 27 months out, is highly dependent on the volatility presented within the 27 month LME price. This methodology would therefore determine that the magnitude of the adjustment to the Consensus long term forecast prices would be subject to significant variations, depending on the specific date on which the 27 month LME price was sourced.[1262]

The AER has therefore developed its own projections using LME futures prices up to 2010 and Consensus Economics' long-term (7.5 years) forecast, then interpolating between the two data sources.

The AER's updated (as at September 2008) estimates for copper and aluminium price forecasts are shown alongside CEG's proposed approach (based on January 2008 and updated August 2008 data) forecasts in figures N.1 and N.2.[1263]

Figure N.1: AER's estimate and CEG's proposal on forecast copper price ($US/tonne, nominal)

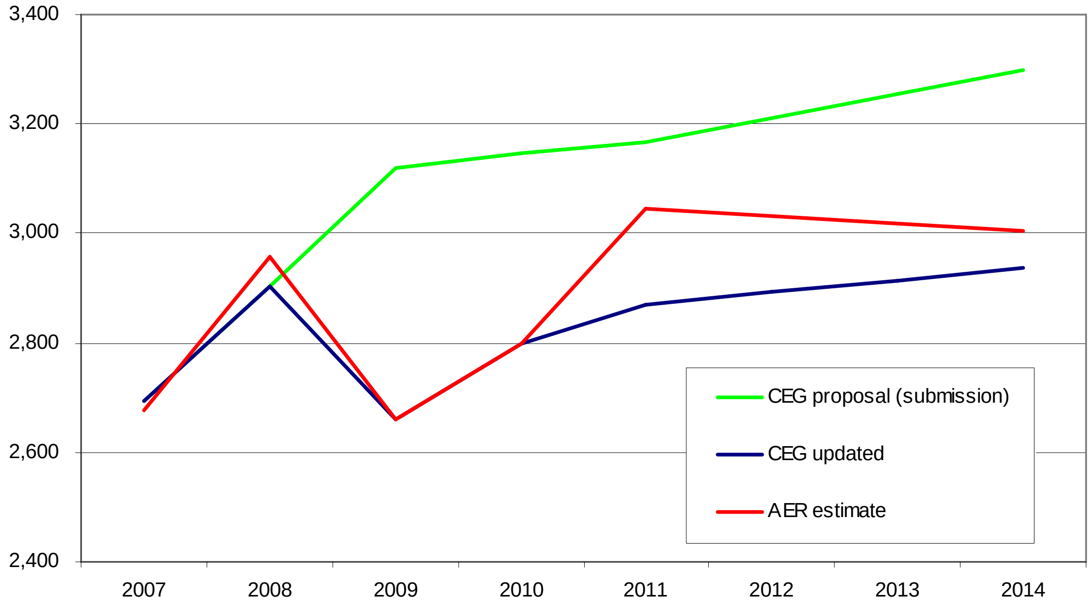


[1262] SKM, *ElectraNet Transmission Network Revised Revenue Proposal 2008-2013*, p. 38.

[1263] Note that figures 3 and 4 are in $USD prices/tonne to avoid complications associated with exchange rate movements. In $USD the individual impact of new data and the removal of the CEG adjustment can be more easily illustrated.

Source: CEG, *NSW electricity businesses*, pp. 11–17; AER analysis.

Figure N.2: AER's estimate and CEG's proposal on forecast aluminium price ($US/tonne, nominal)



Source: CEG, *NSW electricity businesses*, pp. 17–19; AER analysis.

As figures N.1 and N.2 illustrate, copper and aluminium price forecasts have decreased since CEG's proposal was made. For comparative purposes the AER has calculated the CEG forecasts using updated data. The difference between the 'AER estimate' and 'CEG updated' series over 2010–14 reflects the key difference in methodology, with the AER not escalating the Consensus Economics long-term forecast to reflect the difference between that forecast and LME futures prices.

The AER also assumes the mid-point (7.5 years) for Consensus Economics' long-term forecast, rather than the end point (10 years) as proposed by CEG.

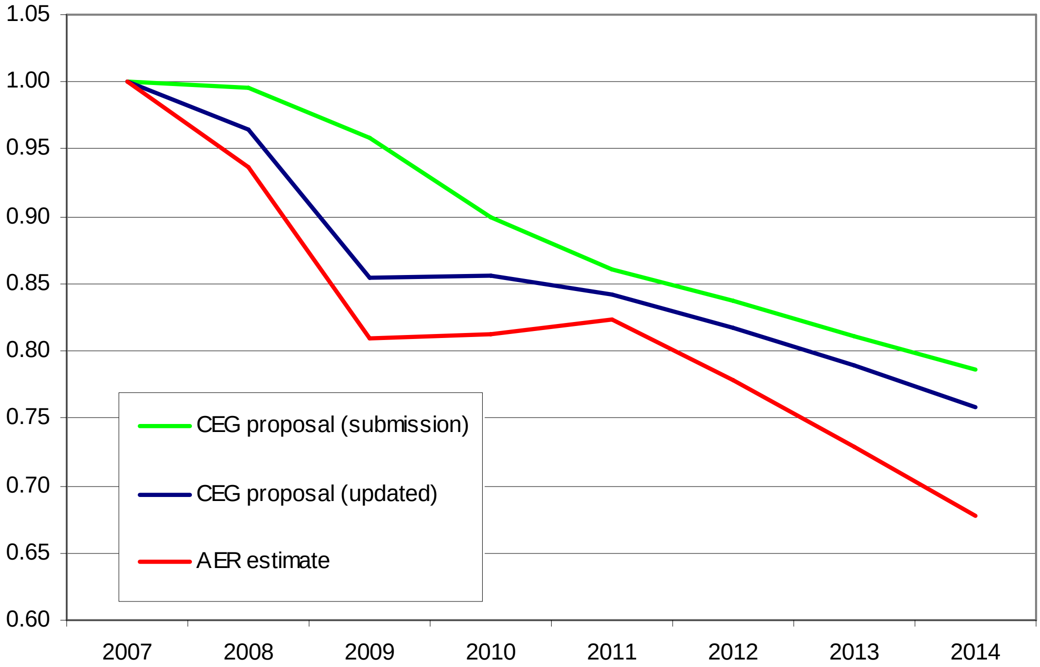
Since all aluminium and copper prices from LME and Consensus Economics were in nominal US dollar (USD) terms, all the projections were converted into nominal Australian dollars (AUD) using the following steps:

- convert nominal USD to nominal AUD using the RBA's latest actual and Econtech's forecast exchange rates[1264] (see section N.5.4)
- convert nominal AUD to real AUD June 2009 using actual and forecast CPI based on the AER's methodology[1265]
- convert into a real cost escalation index (with a base year of 30 June 2007).

[1264] Econtech, *Australian National, State and Industry Outlook*, 22 July 2008.
[1265]. RBA, *Statement on Monetary Policy*, August 2008 and http://www.rba.gov.au/Statistics/measures_of_cpi.html.

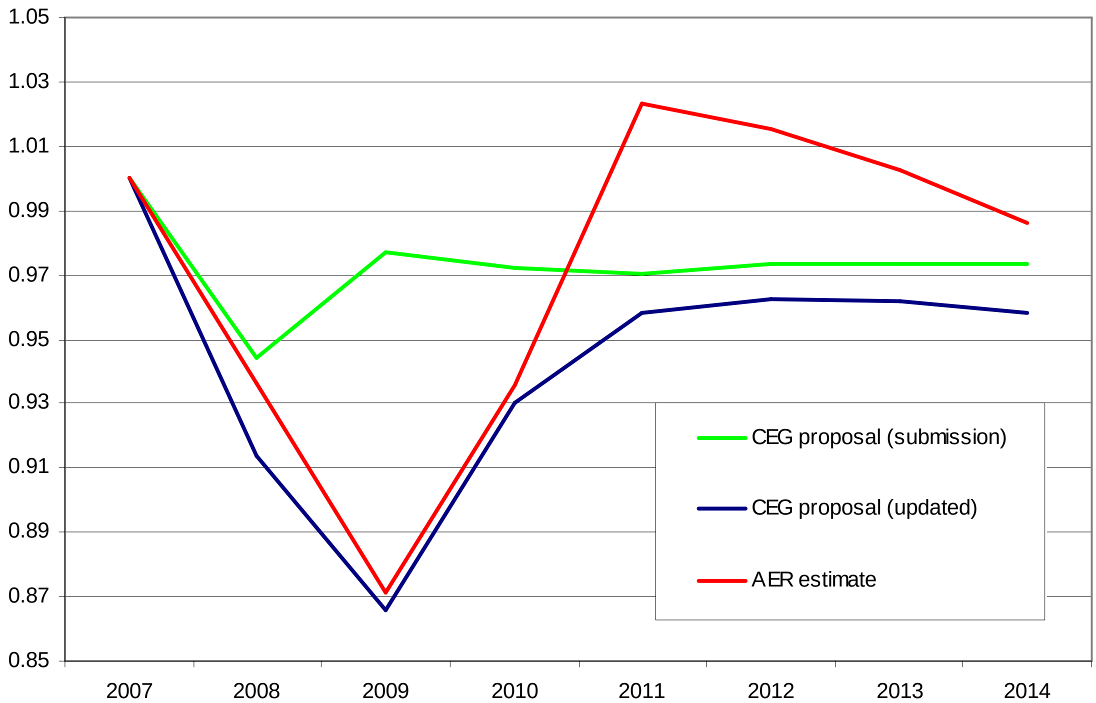
The conversion to real AUD has quite a substantial impact on the results, as shown in figures N.3 and N.4.

Figure N.3: AER's estimate and CEG's proposal on copper cost escalators (index, real $AUD/tonne June 2009, base year = 2007)



Source: CEG, *NSW electricity businesses*, pp. 11–17; AER analysis

Figure N.4: AER's estimate and CEG's proposal on aluminium cost escalators (index, real $AUD/tonne June 2009, base year = 2007)



Source: CEG, *NSW electricity businesses*, pp. 17–19; AER analysis.

In accordance with its preference to use updated data where possible and based on the methodology applied in this draft determination, the AER will incorporate updated LME and Consensus Economics data for its final determination.

N.5.1.4 AER conclusions

The AER is not satisfied that the methodology recommended by CEG and relied upon by the NSW DNSPs reflects a realistic expectation of input costs, required to meet the capex and opex objectives of the transitional chapter 6 rules, over the next regulatory control period.

The AER considers it is appropriate to forecast copper and aluminium prices by using LME futures prices up to 2010 and the long-term Consensus Economics forecast (7.5 years), then interpolate between the two data sources. However, adjusting the long term price of copper and aluminium by the difference between the LME 27–month forward contract price and the corresponding Consensus Economics long-term forecast is inappropriate and unnecessary.

Based on September/October 2008 data for this draft determination, the AER's conclusions on real copper and aluminium escalators for the 2007–14 period are presented in table N.12.

Table N.12: AER's conclusions on real copper and aluminium cost escalators (per cent)

	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
Copper	–6.3	–13.5	0.3	1.4	–5.6	–6.3	–7.0
Aluminium	–6.3	–7.0	7.5	9.3	–0.8	–1.3	–1.6

N.5.2 Steel

N.5.2.1 CEG/NSW DNSPs

CEG stated that because there is currently no futures market for 'mill gate' steel to forecast steel prices, it has relied on Consensus Economics short and long-term price forecasts for hot–rolled coil (HRC) steel traded in the US and in Europe.[1266] CEG took the average of the US and European long-term forecasts over the 5 to 10 year horizon, which produced a forecast average decrease in real HRC prices of 11 per cent over next 10 years. CEG considered the long-term should be interpreted as 10 years and, based on this assumption, forecast an average annual real price reduction of 1.2 per cent for HRC steel.[1267]

CEG then used ABS input-output data to derive the cost contribution of materials and inputs used by producers that transform HRC steel into products for use by Australian NSPs. CEG looked at three types of fabricated steel products, and derived the average

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[1266] Consensus Economics, *Energy & metals consensus forecasts: Minerals Monitor*, 28 January 2008.
[1267] CEG, *NSW electricity businesses*, p. 23.

weighting of ‘iron and steel’ content as 14 per cent and ‘employee compensation’ as 26 per cent of fabricated steel, by cost.[1268]

CEG has applied its HRC real escalator of –1.2 per cent to the iron and steel component (weighted at 14 per cent), and adopted an Econtech general wage (real) growth forecasts from December 2007 for the employee compensation component (weighted at 26 per cent). The CEG methodology assumes that all other cost components (weighted at 60 per cent) of the fabricated steel product would remain unchanged in real terms. Table N.13 sets out CEG’s recommended real escalators for steel products, as derived using the weighted input components.

Table N.13: CEG’s proposed real escalators for steel products (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Steel products	0.2	0.1	0.3	0.2	0.2	0.2	0.2

Source: CEG, *NSW electricity businesses*, p. 1.

N.5.2.2 AER considerations

The AER has concerns with the derivation of CEG’s fabricated steel escalator and considers the approach should be modified to be consistent with the escalators used for other base metals such as copper and aluminium. The AER’s reasoning and subsequent amendments to the CEG methodology, and the resulting steel escalator, are set out below.

HRC steel component

The Consensus Economics estimates applied by CEG are derived from commodity price forecasters’ long and short-term HRC steel price expectations for trading in the US and European markets. The AER accepts that CEG’s reliance on US and European forecasts may not produce an ideal forecast for the cost of fabricated steel used in the production of equipment purchased by NSPs, as this may be sourced from other markets. However, in the absence of more geographically accurate forecasts, the AER considers that the averaging of the US and European long-term market forecasts results in a reasonable approximation for the future price of HRC steel that affects the costs faced by Australian NSPs. The AER will reconsider the appropriateness of using these data should an alternative source arise in the future.

The AER notes that the updated Consensus Economics data reports price expectations in Europe relative to metric tonnes whilst those in the US represent ‘short tons’.[1269] This difference does not appear to have been noted by CEG in its original analysis. To allow meaningful average future price movements to be derived from these two data sets, the AER has scaled the US short ton data to metric tonnes, before taking the average of both series.

[1268] CEG sourced these data from ABS catalogue No 5209.0.55.001. The three types of steel products categories referenced are structural metal products, sheet metal products and fabricated metal products.

[1269] A metric tonne is equivalent to 1.1023 short tons.

The AER has obtained the most recent Consensus Economics HRC steel price forecasts[1270] and has recalculated the HRC component escalator, using the methodology set out in CEG's report, but taking the long-run forecast to represent 7.5 years for the purposes of data interpolation. This is consistent with the assumption that a 5 to 10 year horizon is reflective of the long-term, of which 7.5 years is the mid point. For the period to 2007–08 the AER has obtained Bloomberg historical data on HRC steel prices in the US and Europe.

As figure N.5 illustrates, HRC steel prices have increased significantly since 2007 and are expected to peak in 2008 before declining over the next regulatory control period.

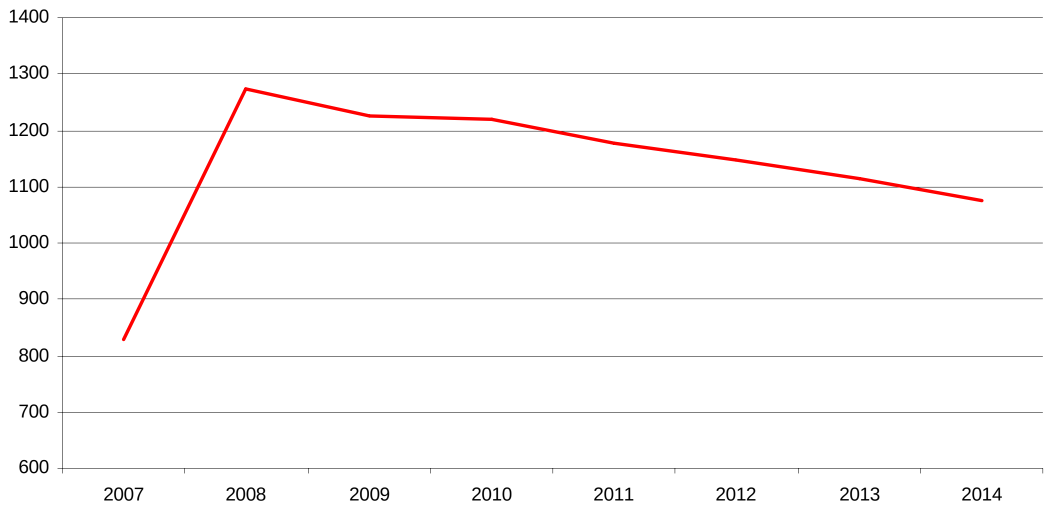
Table 14 sets out the AER's updated actual and forecast HRC steel prices.

Table 14: AER's estimate of real HRC steel prices (AUD/metric tonne)

	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
HRC prices	827.6	1273.3	1225.6	1218.8	1177.3	1147.9	1113.5	1075.7
% change	–	53.8	–3.7	–0.6	–3.4	–2.5	–3.0	–3.4

Source: Consensus Economics, June 2008; AER analysis.
Note: Average of US and European HRC contract prices

Figure N.5: AER's estimate of HRC steel prices (real AUD/metric tonne, June 2009)



Labour and "other" components

CEG has incorporated a labour component into its estimate of fabricated steel escalators, weighted at 26 per cent of production cost. CEG has assumed that this cost component will experience positive real growth during the next regulatory control

1270 Consensus Economics, *Energy & metals consensus forecasts: Minerals Monitor*, 28 July 2008.

period. The rate of this growth has been estimated using Econtech's general wage forecasts across the Australian economy.[1271]

The remaining input cost components of fabricated steel identified by CEG include profits margins and taxes. These are weighted at 60 per cent by input cost and are assumed to remain constant in real terms in the calculation of the CEG fabricated steel escalator.[1272]

CEG has used Australian ABS input-output tables to derive the proportion of labour costs in fabricated steel production in Australia. The AER's considerations on the CEG methodology for introducing a producers' labour input cost component and producers margin escalator (see section N.2 and N.3.2.5) are also applicable in the case of steel manufacturing. The AER has concerns about the introduction of this type of cost escalation factor, and also notes that CEG has not substantiated that the Australian input-output and wage data presented are relevant to its claims. Accordingly, the AER does not accept CEG's proposed labour cost component for steel.

CEG has developed escalators for other base metals such as copper and aluminium, and has relied on the prices of less processed inputs as proxies for copper and aluminium products used in equipment purchased by NSPs. The AER considers the same approach should be applied for fabricated steel, and has decided to use the most recent long-term Consensus Economics HRC steel forecasts as a proxy for changes in the price of fabricated steel, weighted at 100 per cent. This therefore removes the distinction between CEG's proposed input components to the fabricated steel escalator and simplifies the derivation of the escalator. This is consistent with the approach to forecasting other metals cost escalators.

N.5.2.3 AER conclusions

The AER is not satisfied that the methodology for forecasting steel prices, including recognition of indirect labour, profits and taxes in these prices, recommended by CEG and relied upon by the NSW DNSPs, reflects a realistic expectation of input costs over the next regulatory control period.

For this draft decision the AER has obtained updated Consensus Economics HRC steel price forecasts and has recalculated the HRC component escalator taking the long-run Consensus forecast to represent 7.5 years for the purposes of data interpolation. For the period to 2007–08 the AER has obtained Bloomberg historical data on HRC steel prices in the US and Europe. For its final decision and determination the AER will consider the use of latest data under this methodology.

The AER's conclusion on CEG's proposed real steel cost escalators for the next regulatory control period is set out in table N.15.

[1271] CEG, *NSW electricity businesses*, p. 31.
[1272] CEG, *NSW electricity businesses*, p. 29.

Table 15: AER's conclusion on real fabricated steel escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
AER	45.4	3.4	–1.7	–2.4	–2.5	–3.0	–3.4

N.5.3 Crude oil

N.5.3.1 CEG/NSW DNSPs

CEG stated that the New York Mercantile Exchange (NYMEX) crude oil light futures price is a reliable predictor of future crude oil prices.[1273]

The escalations are calculated using:

- US Department of Energy for historical data to June 2007
- the NYMEX crude oil light futures data, converted to Australian dollars (AUD) using Reserve Bank of Australia (RBA) historical exchange rate data and the AUD/US exchange rate forecast from the Econtech 2007 ANSIO report.

CEG has proposed (based on data downloaded on 6 January 2008) escalation rates for crude oil set out in table N.16.

Table N.16: CEG's proposed real escalators for crude oil ($nominal)

	2006-07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
USD prices	60.0	85.3	99.4	96.9	96.5	97.0	96.3	96.7
% change		42.2	16.5	–2.5	–0.4	0.5	–0.7	0.4
AUD price	76.3	97.8	112.9	111.2	112.4	114.6	115.1	116.9
% change		28.1	15.4	–1.4	1.0	2.0	0.5	1.5

Source: CEG, *NSW electricity businesses*, p. 25.

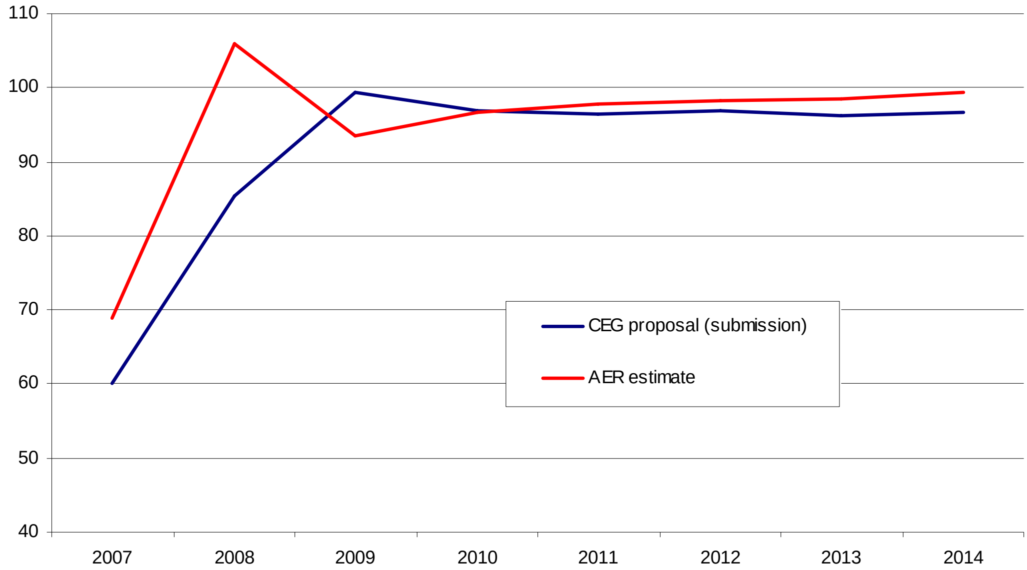
N.5.3.2 AER considerations

In its recent ElectraNet transmission determination, the AER accepted CEG's proposed data sources and considered that they can be used to provide reliable estimates of both actual and forecast crude oil price escalators.[1274] The AER remains of this view and maintains its position that the NYMEX crude oil light futures prices should be averaged over 20 trading days to remove day-to-day volatility.

The AER has taken a 20-day average of daily NYMEX crude oil light futures prices, which results in updated crude oil forecasts.[1275] The AER's updated estimate of crude oil prices ($US/barrel, nominal) is presented alongside CEG's proposed estimates in figure N.6.

[1273] CEG, *NSW electricity businesses*, p. 25.
[1274] AER, *ElectraNet final decision*, pp. 42–45.
[1275] The AER's sample period was between 22 September and 17 October 2008.

Figure N.6: AER's estimate of crude oil prices (AUD/barrel, nominal)



As figure N.6 indicates, crude oil futures prices are relatively unchanged since the CEG report.

The AER converted the NYMEX forecasts into real Australian dollars using Econtech's forecast exchange rate (see section N.5.4), and the AER's methodology for forecast CPI (see chapter 11).

N.5.3.3 AER conclusions

The AER considers that the 20 day average of NYMEX crude oil light futures prices produces forecasts that reflect a realistic expectation of input costs, required to meet the capex and opex objectives of the transitional chapter 6 rules, over the next regulatory control period. In accordance with its preference to use the most recent data where possible, the AER's final determination will incorporate updated NYMEX data when the determination is published in April 2009.

Using data published at the time of this draft decision, the AER's conclusion on crude oil escalators is set out in table N.17.

Table N.17: AER's conclusion on real crude oil (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
AER	43.5	–13.4	1.5	1.7	0.1	–0.6	–0.1

N.5.4 Exchange rate

N.5.4.1 CEG/NSW DNSPs

CEG proposed using Econtech's 2007 ANSIO report forecast of AUD/USD exchange rates, as set out in table N.18.

Table N.18: CEG's proposal on AUD/USD exchange rate forecast, as at 1 July

	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
AUD per USD	0.85	0.88	0.88	0.87	0.85	0.84	0.83

Source: CEG, *NSW electricity businesses*, p. 40.

N.5.4.2 AER considerations

The AUD/USD exchange rate forecasts are used to convert escalators based on futures/market prices (e.g. crude oil, steel prices etc) which are only quoted in US dollar terms.

Exchange rates are a particularly volatile economic variable, driven by numerous factors and are consequently notoriously difficult to forecast in the short, medium and long-term. While the AER accepted the use of an Econtech exchange rate forecast in its recent ElectraNet transmission determination, it notes that the potential volatility of exchange rates brings any single source of forecast into question. Table N.19 sets out Econtech's June 2008 AUD/USD exchange rate forecast.

Table N.19: Econtech's AUD/USD exchange rate forecast, as at 1 July

	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
AUD per USD	0.85	0.96	0.88	0.84	0.82	0.80	0.75

Source: Econtech, *Australian National State and Industry Outlook*, 22 June 2008, p. 110.

Events in recent months demonstrate the volatility of exchange rate movements, with the AUD/USD exchange rate peaking at US$0.98 on 16 July 2008 before falling back (by 42 per cent) towards US$0.69 on 17 October 2008. The peak in July was heavily influenced by positive sentiment towards the AUD driven by Australian/US interest rate differentials, strong commodity prices, the downturn in the US economy, housing market and US bank write-downs. The recent reduction resulted from negative sentiment on the AUD stemming from reductions in official interest rates and slowing commodity price growth.

The exchange rate forecasts proposed by both CEG and SKM from Econtech use forecasts of an exchange rate at five points in time only through the next regulatory control period—that is, the exchange rate on 1 July of each year. However, irrespective of the accuracy of the Econtech's exchange rate forecasting, the very nature of a point in time forecast, particularly in a volatile market, is not necessarily likely to be representative of the AUS/USD exchange rate faced by businesses purchasing equipment throughout the next regulatory control period.

The AER notes that there is little apparent difference between Econtech's latest forecasts and those used as part of the NSW DNSPs' proposals, and will rely on the Econtech forecasts. As current exchange rates have moved significantly since the DNSPs submitted their proposals the AER will take account of the actual exchange rate at the time of its final decision and determination in 2009.

N.5.4.3 AER conclusions

The AER considers that an exchange rate forecast prepared by Econtech at the time of the final decision will represent a realistic expectation of forecast exchange rates over the next regulatory control period. Using more recent data from this source, the AER's conclusion on the AUD/USD exchange rate forecast for this draft decision is set out in table N.20. The AER will obtain updated data from this source for its final determination.

Table N.20: AER's conclusion on AUD/USD exchange rate forecast, as at 1 July

	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
AUD per USD	0.85	0.96	0.88	0.84	0.82	0.80	0.79

Source: Econtech, *Australian National State and Industry Outlook*, 22 June 2008, p. 110.

N.5.5 Producer's margin

N.5.5.1 CEG/NSW DNSPs

CEG has recommended that the NSW DNSPs apply a producer's margin to escalate equipment cost inputs for the next regulatory control period.[1276]

CEG proposed that this is a legitimate cost that DNSPs could face in the current economic environment, and should be recoverable under the AER's regulatory framework. According to CEG, a producer's margin reflects the currently limited global supply of transmission and distribution equipment compared to large growth in global demand.[1277]

The CEG methodology for calculating a real forecast producer's margin is based on averaging the growth rate of forecast margins from JP Morgan and Goldman Sachs for three European producers of electricity equipment – ABB, Prysmian and Nexans.[1278] Table N.21 sets out CEG's findings on a producer's margin escalator.

CEG noted that JP Morgan's figures are based on earnings before interest and taxes (EBIT) while Goldman Sachs figures are based on earnings before interest, taxes, depreciation and amortization (EBITDA). CEG acknowledged that given the limited data sources available to measure producers' margins:[1279]

> …it is always possible that ABB, Prysmian and Nexans are 'special cases' of equipment suppliers that, peculiar to the rest of their competitors, can expect to earn high margins in future years. However, while we cannot locate similar long term forecasts for other firms, we note that short term forecasts by Goldman Sachs has similarly robust forecasts of earnings growth across all firms in the sector.

1276 CEG, *Escalation factors affecting expenditure forecasts*, April 2008.
1277 CEG, *NSW electricity businesses*, pp. 32–34.
1278 CEG, *NSW electricity businesses*, p. 37.
1279 CEG, *NSW electricity businesses*, p. 35.

CEG also stated that it has assumed zero growth in producers' margins beyond the forecast horizon to 2011, given the absence of data.[1280]

Table N.21: CEG's proposal on real escalators for producer's margin (per cent)

	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
ABB Power Products (JP Morgan)	3.6	2.9	n/a	n/a	n/a	n/a	n/a
ABB Power Systems (JP Morgan)	7.5	5.8	n/a	n/a	n/a	n/a	n/a
Prysmian (JP Morgan)	18.8	9.9	6.3	7.6	n/a	n/a	n/a
ABB (Goldman Sachs)	5.1	3.0	n/a	n/a	n/a	n/a	n/a
Prysmian (Goldman Sachs)	9.9	5.4	6.0	n/a	n/a	n/a	n/a
Nexans (Goldman Sachs)	11.8	5.3	n/a	n/a	n/a	n/a	n/a
CEG's average producer's margin	9.5	5.4	6.1	7.6	0.0	0.0	0.0

Source: CEG, *Escalation factors affecting expenditure forecasts*, table 24.

N.5.5.2 AER considerations

As noted in section N.2, the AER considers that the introduction of a new producer's margin escalator is inappropriate as it:

- represents a movement beyond the AER's obligation to provide regulated businesses a reasonable opportunity to recover efficient costs towards providing . compensation for changes in input costs at a very fine level of detail. The AER considers it sufficient to monitor whether the cost of finished goods, as opposed to the component parts, need to be escalated above or below CPI
- is not supported by robust data.

Producers' margins will already be embedded in the DNSPs' base cost estimates (i.e. as at 31 June 2007). What is in question is the extent to which the existing producers' margins are expected to change in real terms over the forthcoming regulatory control period and, if a real change is expected, how to reliably measure it.

CEG has recommended the use of EBIT and EBITDA to measure producer's margins. The producer's margin being measured is defined as the difference between the price of a unit and the cost of producing that unit. Increases in EBIT (or EBITDA) could be the result of:

- an increase in prices, and/or

[1280] CEG, *NSW electricity businesses*, p. 37.

- an increase in volumes, and/or
- a decrease in costs.

This was noted by ABB (one of the equipment suppliers examined by CEG), in its latest financial report:

> EBIT and EBIT margin rose, mainly reflecting the improved cost efficiency of higher factory loadings, continuing operational improvements and a supportive pricing environment.[1281]

On this basis the AER considers that it is unreasonable to use EBIT (or EBITDA) as a direct proxy for margins (or increased prices). The AER does not consider it appropriate to allow the DNSPs to recover costs associated with other aspects of an increase in EBIT.

The AER also notes CEG's acknowledgement that there are limited long-term forecasts of producers' margins available, and considers this to be a significant issue in forming an estimate with any degree of reliability. CEG has used six forecasts (see table 19 above). Effectively CEG is basing its forecasts on a sample of three firms. In doing so CEG has not demonstrated that these firms are representative of the entire market supplying equipment to Australian electricity network service providers. Furthermore, as noted by PB, the forecasts of margins beyond 2009 are dependent on six data points of three companies from two different forecasters (Goldman Sachs and JP Morgan).

N.5.5.3 AER conclusions

As noted above the AER has general concerns regarding the introduction of a producer's margin escalator. Also, the data used to substantiate these costs are not robust. In the AER's view, the estimates of a producer's margin presented by CEG:

- are highly uncertain,
- are based on forecasts of few equipment suppliers, and
- contain unreasonable assumptions about the relationship between EBIT (and EBITDA) and price increases.

The AER rejects the producer's margin escalators proposed by CEG as it does not meet the underlying objective for inclusion in forecast costs under clause 6.5.7(c) of the transitional chapter 6 rules. Specifically, the information presented by CEG is not sufficient to satisfy the AER that the associated expenditure reasonably reflects a realistic expectation of cost inputs over the next regulatory control period. The AER considers their addition would represent a movement beyond the AER's obligation to provide a reasonable opportunity to recover efficient costs and also represent a level of compensation for costs that is inconsistent with the general incentive framework.

[1281] ABB's 2008 second quarter results, accessible at: http://www.abb.com/cawp/seitp202/b4ca86e07eeda409c125749000162bcb.aspx

The effect of the AER's decision is to not apply any real escalator to that proportion of costs identified by EnergyAustralia and Country Energy attributed to a producer's margin. That is, the proportion of base costs associated with producer's margins will be apportioned to the "other" escalation category and be escalated by CPI. Note that this decision is not applicable to Integral Energy as it did not propose to apply this escalator.

N.5.6 Construction costs

N.5.6.1 CEG/NSW DNSPs

The NSW DNSPs obtained advice from CEG to forecast construction cost escalators.[1282] The construction cost escalator incorporates both materials and labour costs. CEG concluded that an average of the total engineering construction cost escalators calculated by Econtech[1283] and Macromonitor[1284], deflated by CPI, provides an appropriate real estimate of construction costs. [1285]

The Econtech, Macromonitor and CEG construction cost forecasts are set out in table N.22.

Table N.22: CEG's proposal on real construction cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Econtech	0.2	0.6	1.3	1.1	1.2	1.8	2.4
Macromonitor	4.3	3.5	0.5	0.3	1.0	2.1	2.8
CEG	2.3	2.1	0.9	0.7	1.1	1.9	2.6

Source: CEG, *NSW electricity businesses*, April 2008, p.27.

N.5.6.2 AER considerations

The Econtech engineering construction cost forecasts used by CEG were obtained from the Construction Forecasting Council's (CFC) website. The AER has obtained updated engineering construction cost forecast from this source and deflated them by CPI in order to provide real forecasts.[1286] The AER notes that there is no publicly

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1282 CEG, *NSW electricity businesses*, April 2008; CEG, *Transend*, April 2008.

1283 The Econtech forecast was obtained from the construction council forecasting website at http://www.cfc.acif.com.au/. CEG advised that the data it used was updated on 15 November 2007.

1284 Macromonitor, *Australian Construction Outlook 2008*, November 2007; Macromonitor, *Forecasts of cost indicators for the electricity transmission sector, New South Wales & Tasmania*, February 2008, p. 19.

1285 The total engineering construction cost forecasts used by Macromonitor and Econtech are based on the ABS publication, *Engineering Construction Activity, Australia* (ABS catalogue no. 8762.0). This publication contains estimates of engineering construction activity in Australia, which were compiled from the Engineering Construction Survey. This survey measures the value of all engineering construction work undertaken in Australia. This value excludes the cost of land, repair and maintenance activity, the value of any transfers of existing assets, the value of installed machinery and equipment not integral to the structure and the expenses for relocation of utility services. However, a contract for the installation of machinery and equipment which is an integral part of a construction project is included. Construction projects covered by the survey include bridges, railways, pipelines, power stations, transmission/distribution electricity lines.

1286 Econtech, *Australian National State and Industry Outlook*, 22 July 2006.

available updated data on engineering construction costs from Macromonitor. The updated Econtech forecasts for engineering construction costs are shown in table N.23.

Table N.23: Econtech's real engineering construction cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
Updated Econtech engineering	–0.3	–1.9	0.4	1.2	1.1	1.0	1.0	0.9

Source: Construction Forecasting Council website http://www.cfc.acif.com.au/.
Note: The average is calculated for 2009–10 to 2013–14 (the next regulatory control period). The figures provided on CFC's website take into account data and other information available up to 1 May 2008.

There is some difference between the construction cost forecasts provided by CEG and the updated Econtech construction cost forecast. Given the change in economic conditions since 2007, the AER considers that it is reasonable to adopt the updated Econtech construction cost forecasts as they reflect the most recent information and therefore are a reasonable expectation of movements in construction costs into the next regulatory control period.

Further, the AER does not consider it appropriate to rely on the forecasts presented by Macromonitor because there is little information available on the methodology used to forecast engineering construction costs.

Accordingly, the AER is not satisfied that CEG's construction cost escalators reflect a realistic expectation input costs, required to meet the capex and opex objectives over the next regulatory control period. The AER will apply the updated Econtech construction cost forecasts EnergyAustralia's and Integral Energy's capex proposals. Note that this decision is not applicable to Country Energy as it did not identify any construction capex in its proposal.

N.5.6.3 AER conclusions

The AER's conclusion on forecast construction cost escalators is set out in table N.24.

Table N.24: AER's conclusion on real construction cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
AER	–0.3	–1.9	0.4	1.2	1.1	1.0	1.0	0.9

N.6 Lag in application of escalators

In its draft decision for the SP AusNet transmission determination, the AER reviewed a proposal from SKM to recognise a 1−2 year lag effect between base metals prices (i.e. copper, aluminium) and transmission equipment prices (i.e. power transformers, switchgear). Based on an analysis of the movements in base metals prices against relevant producer price indices (PPIs) published by the Australian Bureau of Statistics (ABS), the AER concluded that:

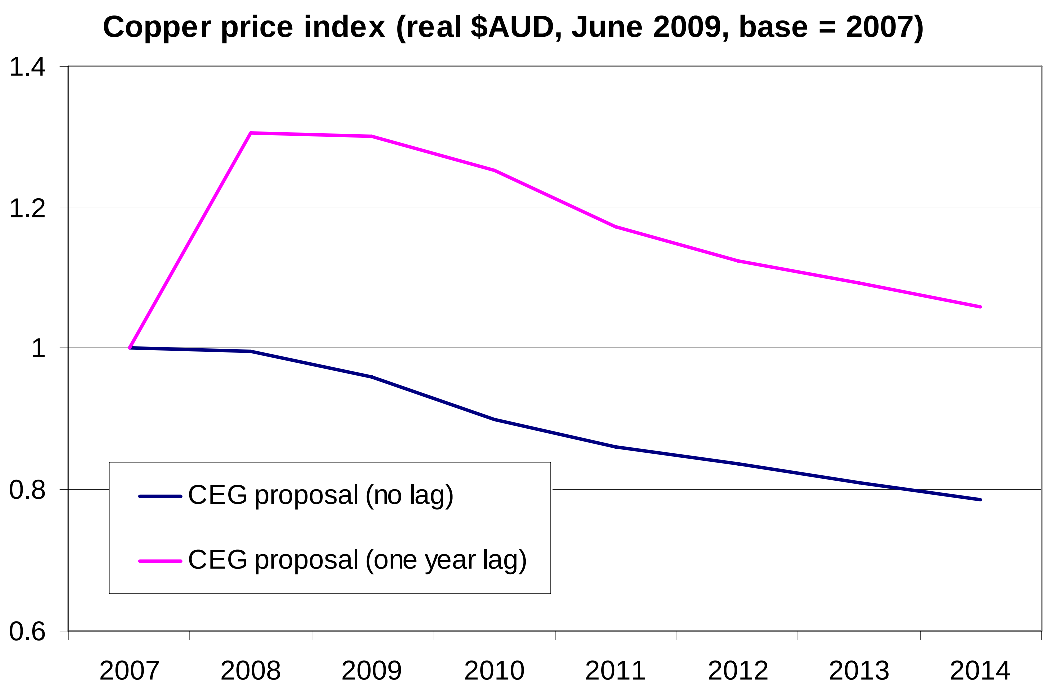
> On the balance of the available information SKM's assumption of a lag between movements in base metals prices and transmission equipment prices appears reasonable, however the AER considers that the lag is not likely to be greater than one year over the forthcoming regulatory control period.[1287]

The effect of this was to 'shift' the peak in base metals prices from 2006−07 to 2007−08, on the assumption that movements in transmission equipment prices lag movements in base metals prices by twelve months.

In its latest report CEG has recommended applying a one year lag to copper and aluminium, consistent with the AER's decision for SP AusNet.[1288] CEG also recommended applying a lag to crude oil prices, and EnergyAustralia has applied a one year lag to labour costs.

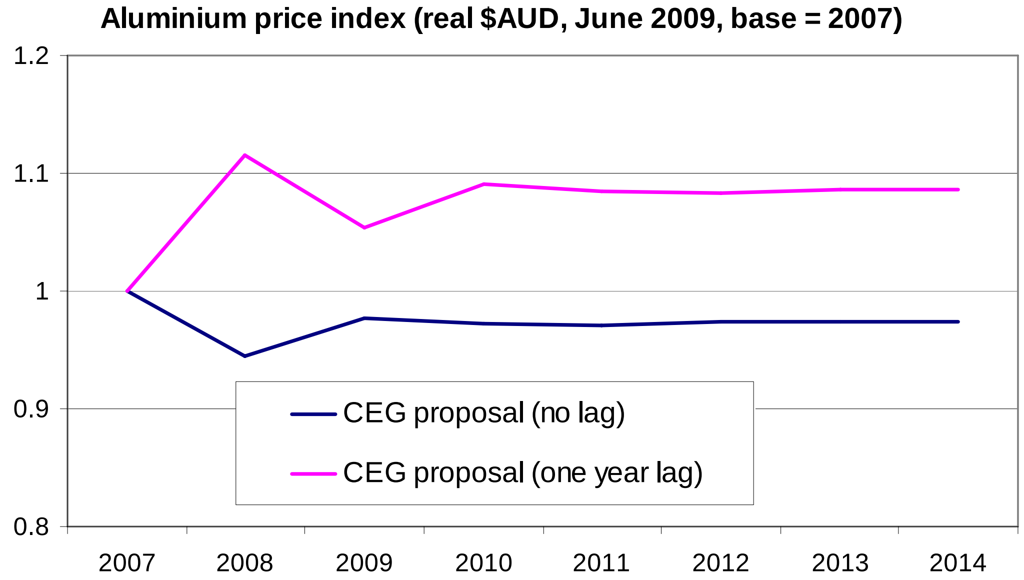
As figures N.7 and N.8 illustrate for copper and aluminium, the effect of the one year lag assumption is to increase the real escalation for these inputs applied over the 2007−14 period.

Figure N.7: CEG's proposal with one year lag in copper prices



[1287] AER, *SP AusNet Draft decision*, p. 90.
[1288] AER, *SP AusNet Draft decision*, p. 90.

Figure N.8: CEG's proposal with one year lag in aluminium prices



Source: CEG,[1289] AER analysis

It is noted that neither CEG nor the businesses currently subject to review have presented any new evidence to justify a lag between movements in base metals and equipment prices. In particular, there has been no evidence presented to support a lag between:

- movements in crude oil prices and electrical equipment prices
- movements in labour cost indices and the actual labour costs faced by network businesses e.g. as proposed by EnergyAustralia.

Therefore, given the lack of evidence to support the proposal, the AER is not satisfied that crude oil prices and labour costs estimated through the application of a lag reflect the cost inputs required to achieve the capex and opex objectives over the next regulatory control period.

The AER has also re-examined the case for a one year lag application of base metals such as copper and aluminium escalators, using similar analysis to that presented in the SP AusNet transmission determination and taking account of further data that is now available. It is noted that at the time of the SP AusNet decision, the extent of a lag in the data was somewhat unclear, as noted by the AER:

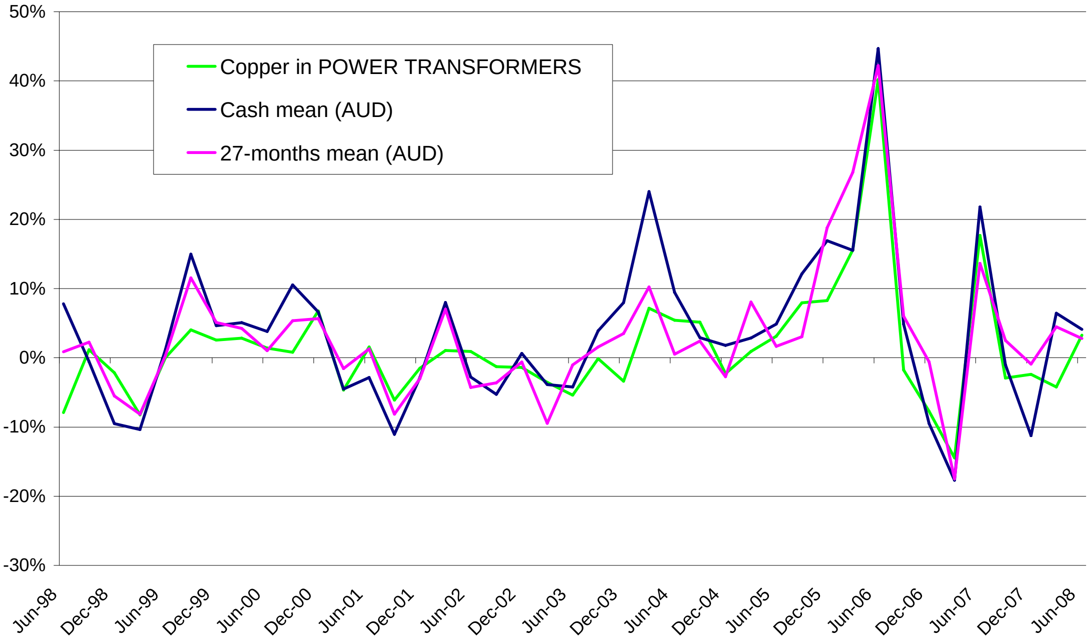
> Overall, growth in the PPI appears to track growth in base metals prices quite closely after 2005, possibly indicating a greater flexibility built into contracts after this point in time. The data tends to suggest that any significant lag (i.e. >1 year) persistent over the period 2003-2005 may have been transitory, and has since subsided. Further, given that base metals prices are expected to return to around the long-run average over the period 2006-07 to 2013-14, the

[1289] CEG, *NSW electricity businesses*, April 2008, pp. 40–43.

two indices may begin to track quite closely again (as in the pre-boom period 1998-2002).[1290]

Figures N.9 and N.10 show the quarterly change in LME prices for copper and aluminium against ABS PPIs over the period 1998−2008.

Figure N.9: LME and PPI copper prices, quarterly % change 1998–2007 (AUD, nominal)



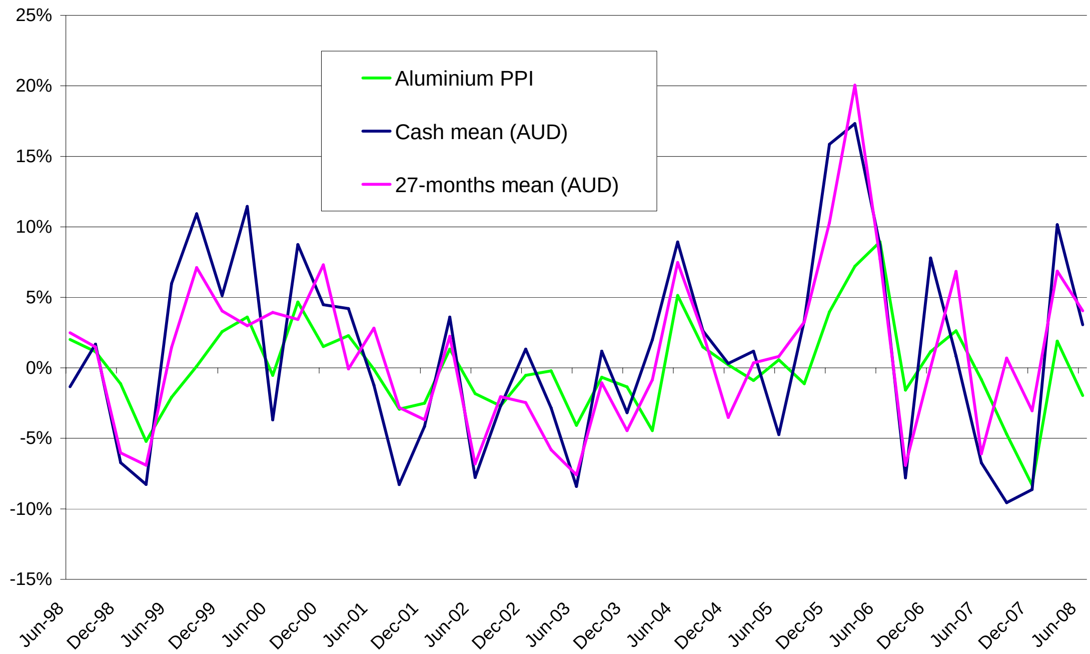
Sources: LME;[1291] ABS[1292]

[1290] AER, *SP AusNet Draft decision*, p. 322.

[1291] LME, *Average Official and Settlement Prices US$/TONNE – Copper* (cash mean, 27-month futures).
LME, *Average Official and Settlement Prices US$/TONNE – Aluminium* (cash mean, 27-month futures).
The LME data is converted into Australian dollars using actual USD/AUD data from the RBA.

[1292] ABS, Cat No: 6427.0 (Table 47) – *Producer Price Indexes, Copper Materials Used in the Manufacture of Electrical Equipment (Power Transformers)*, Australia.
ABS, Cat No: 6427.0 (Table 30) – *Producer Price Indexes, Indexes of Metallic Materials used in the Fabricated Metal Products Industry*, Australia.

Figure N.10: LME and PPI aluminium prices, quarterly % change 1998–2007 (AUD, nominal)



Sources: LME;[1293] ABS[1294]

Although the PPIs examined are imperfect proxies for the electrical equipment purchased by network businesses, the AER considers that they provide a useful indicator of the relative growth rates at various stages of production.

Based on the data presented in figures 9 and 10, the AER does not consider that a lag between movements in base metals and electrical equipment prices is evident. While the two indices clearly do not have a one-to-one relationship, there is a strong correlation—both in the magnitude and timing of price increases. Any lag between movements in base metals and movements in the PPIs selected for analysis appears to be, at most, three to six months, which does not support one year lags recommended by CEG.

On this basis the AER has revised its view from the SP AusNet decision, and now considers that there is no need to recognise a lag between movements in base metals prices and electrical equipment prices. Accordingly, the AER is not satisfied that copper and aluminium prices estimated through the application of a lag reflect the cost inputs required to achieve the capex and opex objectives over the next regulatory control period

[1293] LME, *Copper* (cash mean, 27-month futures).
LME, *Aluminium* (cash mean, 27-month futures).
The LME data is converted into Australian dollars using actual USD/AUD data from the RBA.

[1294] ABS, Cat No: 6427.0 (Table 47) – *Producer Price Indexes, Copper Materials Used in the Manufacture of Electrical Equipment (Power Transformers)*, Australia.
ABS, Cat No: 6427.0 (Table 30) – *Producer Price Indexes, Indexes of Metallic Materials used in the Fabricated Metal Products Industry*, Australia.

Appendix O: Country Energy controllable operating expenditure

O.1 Country Energy proposal

Table O.1 sets out Country Energy's current and forecast controllable opex by cost category and year.[1295]

Table O.1: Country Energy's controllable opex by category ($m, 2008–09)

	Actual			Estimated		Proposed				
	04−05	**05−06**	**06−07**	**07−08**	**08−09**	**09−10**	**10−11**	**11−12**	**12−13**	**13−14**
Network operating	23	29	29	24	17	18	18	18	18	19
Network maintenance	195	202	246	261	264	345	352	364	376	390
Other expenditure	44	34	43	43	36	37	38	40	41	42
Total	262	265	318	328	317	400	408	421	435	451

Source: Country Energy, RIN; and Wilson Cook, volume 4, p. 35.
Note: Totals may not add up due to rounding.

Country Energy's forecast controllable opex for the next regulatory control period is $2116 million, consisting of:[1296]

- network operating ($90 million)
- network maintenance expenditure ($1828 million)
- other opex ($199 million).

The total controllable opex proposed in the next regulatory control period is 42 per cent higher than the estimated $1491 million in the current regulatory control period. Country Energy indicated that the increase in controllable opex over the next regulatory control period reflects:[1297]

- new, deferred and backlog asset inspection and maintenance works to mitigate risk and improve network performance
- cost increases above inflation for labour and input materials
- increased workload due to additional assets.

The step change in opex in 2009−10 accounts for new, deferred and backlog work programs in the network maintenance expenditure category. Country Energy stated that this effectively results from the new policies and requirements that have been

[1295] Controllable opex is total opex less self insurance and debt and equity raising costs.
[1296] Country Energy, RIN proforma 2.2.2.
[1297] Country Energy, *Regulatory proposal*, pp. 55 and 63.

identified, and maintaining its expenditure close to the opex allowance for the current regulatory control period.[1298]

O.1.1 Opex forecasting methodology

Country Energy established an efficient base year and used a broad bottom-up methodology to establish its forecasts of efficient opex for the next regulatory control period. This approach incorporates current 'business as usual' operating and maintenance programs with adjustments for strategic inspection, vegetation control and maintenance programs. Costs were then escalated for increases in input costs and network growth.[1299]

O.1.2 Components of forecast opex

Efficient base year controllable costs

Country Energy used its 2006−07 opex as the base year for forecasting opex in the next regulatory control period. Country Energy stated that it selected 2006−07 on the basis that it is the latest year where actual audited regulatory accounts are available.[1300]

Impact of external factors

While Country Energy indicated that its forecast opex incorporates a step change from the current regulatory control period, Country Energy advised that it had not incorporated any specific step increases arising from new or future obligations in its opex forecasts.[1301]

Proposed step changes

Country Energy indicated that its 2009−10 opex forecast includes a step increase of $91 million to account for new, deferred and backlog asset inspection and maintenance programs to mitigate risk, improve network performance and support general business functions. Country Energy stated that many of these programs were to be commenced in the current regulatory control period in response to changes to Country Energy's licence conditions but were deferred to the next regulatory control period so that it could maintain its opex within the level provided in the current IPART determination.[1302]

Escalators

Country Energy engaged Competition Economists Group (CEG) to determine escalation trends in labour and non-labour (materials) costs for the current and next regulatory control periods.

From this information Country Energy calculated a weighted average real increase in labour and materials costs used to develop the opex forecasts of approximately 1.5 per cent per annum, excluding vegetation management costs. The weighted average real

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[1298] Country Energy, *Regulatory proposal*, p. 36.
[1299] Country Energy, *Regulatory proposal*, pp. 48–49.
[1300] Country Energy, *Regulatory proposal*, p. 46.
[1301] Wilson Cook, volume 4, p. 33.
[1302] Country Energy, *Regulatory proposal*, pp. 35 and 63.

increase in labour and materials costs used to develop the vegetation management forecast is approximately 2.4 per cent per annum. This is due to a high weighting of contractors' costs (which are forecast to escalate at the EGW labour rate), creating a higher weighted escalation rate than used for other maintenance activities.[1303] This real cost escalation adds approximately 10 per cent to the average annual opex in the next regulatory control period compared with the base year.[1304]

Country Energy indicated that growth related capex increases the size of the network and the number of assets to be maintained, operated and managed. Country Energy therefore applied an escalation factor to opex to reflect network growth. Country Energy increased its network-related opex by the proportion of average annual growth-related capex to the estimated total replacement cost of system assets. This ratio is then reduced by 25 per cent to reflect the fact that new assets will not incur condition-based maintenance costs. The result of this is a growth escalation rate of 1.75 per cent per annum.[1305]

The effect of network growth escalation adds approximately 7 per cent to the average annual opex for the next regulatory control period as compared with the base year.

Capex/opex trade off

Country Energy included a reduction in emergency response expenditure to reflect expected benefits from its reliability-related capex program.[1306] The reduction totals $15 million over the next regulatory control period. No trade off between replacement expenditure and opex has been included.[1307]

Productivity savings

Country Energy indicated that the level of proposed opex has been reduced by expected productivity gains due to the refinement of existing work practices. This saving has been calculated in accordance with Country Energy's resource plan and results in a reduction of $16 million in opex over the next regulatory control period.[1308]

O.2 Submissions

The EMRF stated that Country Energy proposed a forecast opex allowance in excess of historical opex spending and expected growth in demand.[1309]

The EUAA noted an increase in Country Energy's forecast opex for the next regulatory control period. It stated Country Energy's average annual forecast opex of $429 million over the next regulatory control period is close to a 40 per cent increase over the expected opex spend in the current regulatory control period of less than

1303 The AER's consideration of this matter is set out in chapter 8.
1304 Country Energy, *Regulatory proposal*, p. 47.
1305 Country Energy, *Regulatory proposal*, p. 55.
1306 Country Energy, *Regulatory proposal*, p. 55.
1307 Wilson Cook indicated that this was appropriate as Country Energy's replacement expenditure is not sufficient to reduce the average weighted age of the network over the next regulatory control period.
1308 Country Energy, *Regulatory proposal*, pp. 55 and 63.
1309 EMRF, pp. 28–29.

$300 million. It stated that it was difficult to assess whether the nature of Country Energy's business had changed so dramatically to warrant the increase.[1310]

O.3 Consultant review

Wilson Cook reviewed Country Energy's proposed opex from a top-down and bottom-up standpoint.

Wilson Cook concluded that the top-down analysis suggests that Country Energy's base year level of expenditure is low based on comparative benchmarking and may be below a prudent level to maintain targeted service levels. Wilson Cook noted that as a relatively new organisation, Country Energy may not have had the processes and systems in place to prepare an adequate forecast and justification for its expenditure at the time of the last regulatory review.[1311]

From the bottom-up analysis, Wilson Cook concluded that Country Energy's forecast scope of work has been prepared on a robust basis. Wilson Cook proposed only one adjustment to Country Energy's opex forecast—relating to vegetation management. Wilson Cook did not consider it appropriate to apply the asset growth escalator to vegetation management on the basis that it is unlikely that the quantity of work in this area will be driven by growth capex. This adjustment resulted in a $30 million reduction to controllable opex over the next regulatory control period.[1312]

Table O.2 compares the Wilson Cook recommended controllable opex to Country Energy's controllable forecast opex.

Table O.2: Country Energy's forecast controllable opex and Wilson Cook's recommended opex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy's controllable opex forecast	400	408	421	435	451	2116
Wilson Cook's recommended controllable opex	398	405	415	427	441	2086
Difference	2	4	6	8	10	30

Source: Wilson Cook, volume 4, p. 42.
Note: Totals may not add up due to rounding.

1310 EUAA, p. 22.
1311 Wilson Cook, volume 4, p. 42.
1312 Wilson Cook, volume 4, p. 41.

O.4 Issues and AER considerations

O.4.1 Country Energy forecasting methodology

Country Energy proposal

Country Energy used a bottom-up methodology to establish its opex forecasts over the next regulatory control period. Country Energy developed a zero based model (RISMO) to project the quantity of inspection, vegetation control and maintenance works needed. This incorporated business as usual costs as well as incremental items with all works prioritised based on risk assessments. The work program was then costed using unit rates in 2006−07 dollar terms. Escalation for cost inputs and asset growth was then added, and an allowance was made for productivity improvements and a reduction in emergency response work resulting from the impact of the proposed reliability capex program. Other categories of expenditure were escalated from their base year levels.[1313]

Consultant review

Wilson Cook reviewed the asset management plans and policies and the principles applied to the risk-based model used to derive the work program. Wilson Cook concluded that the maintenance strategies and processes used by Country Energy are typical of electricity distribution businesses.[1314]

Wilson Cook also stated that inspection cycles and routine maintenance activities were in line with industry standards and the process used to review and identify maintenance requirements appeared to be robust and appropriate. Wilson Cook concluded that Country Energy's maintenance policies and processes are appropriate and properly applied.[1315]

AER considerations

Based on Wilson Cook's advice the AER considers that Country Energy has provided a robust methodology for forecasting its opex requirement for the next regulatory control period. In particular, the AER notes that:

- Country Energy's methodology is similar to that applied by other DNSPs
- the assumptions incorporated into the opex model are reasonable.

O.4.2 Efficient base year

Country Energy proposal

Country Energy used its 2006–07 opex as the base for forecasting future costs. Country Energy indicated that 2006–07 is the latest year where actual audited regulatory accounts are available. Country Energy stated that its 2006–07 opex

[1313] Country Energy, *Regulatory proposal*, pp. 48–49.
[1314] Wilson Cook, volume 4, p. 40.
[1315] Wilson Cook, volume 4, p. 40.

outcomes provide an efficient base level from which to forecast future opex requirements.[1316]

Consultant review

Wilson Cook used a top-down benchmarking approach to assess the efficiency of Country Energy's 2006−07 base year opex. Wilson Cook compared the NSW DNSPs with other DNSPs in the ACT, Victoria, Queensland, South Australia and Tasmania.[1317]

In order to compare the different businesses, Wilson Cook developed a composite 'size' variable.[1318] Wilson Cook concluded that, on a size-adjusted basis—using the composite size variable as a measure of size, Country Energy has costs similar to the average.

Wilson Cook also compared two separate groups of businesses, those that are predominantly urban and those that are predominantly rural. This comparison was made on the opex-per-size measure and the traditional benchmarking measures of: opex $/customer; opex $/MW; and opex $/km.

The analysis of the predominantly urban group was comprised of Energex (QLD), Integral Energy (NSW), EnergyAustralia (NSW), ActewAGL (ACT), Alinta AE (VIC) and United Energy (VIC). The analysis of the predominantly rural group was comprised of Ergon Energy (QLD), Country Energy (NSW), Powercor (VIC), ETSA (SA), Aurora (TAS) and SP AusNet (VIC).

Wilson Cook indicated that the analysis in respect of Country Energy was limited by there being only one closely comparable business—Ergon Energy. However, Wilson Cook concluded that the comparisons suggested that Country Energy is operating close to or a little below the industry norm.

Wilson Cook also noted that Country Energy's 2006−07 expenditure is almost identical to its regulatory allowance[1319] but indicated that the allowance included funding for additional work to comply with the licence conditions.[1320]

In addition to the base year assessment, Wilson Cook analysed the movements in opex that have taken place or are forecast by the NSW DNSPs to occur in the period from 2006−07 to 2013−14 (based on opex by size). Based on this measure, Wilson Cook indicated that Country Energy's expenditure in 2009−10 is forecast to be 20 per cent above that in 2006−07 and is 26 per cent higher by the end of the next regulatory

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1316 Country Energy, *Regulatory proposal*, p. 46.

1317 Adjustments were made to the 2006−07 reported figures of all businesses to remove abnormal and one-off items.

1318 The composite size variable allows networks of differing customer densities to be compared—that is, it allows data to be normalised. The composite size variable was constructed by Wilson Cook using a combination of common network variables (customer numbers, network length and maximum demand). Further information regarding the composite size variable is available in Wilson Cook, volume 1.

1319 Wilson Cook, volume 4, p. 37.

1320 Country Energy received a cost pass through allowance to meet these licence requirements, but indicated that it chose to defer this work program to the next regulatory control period.

control period. Wilson Cook indicated that the rate of increase from 2006−07 to 2009−10 was high, due to opex deferred in the current regulatory control period.[1321]

Since a significant part of the increases in opex are due to real cost escalation, mainly in labour, Wilson Cook calculated an approximate labour cost escalator and used it to remove the effects of real labour cost escalation to identify the changing opex levels without it. On this basis Country Energy's 2009−10 opex per size is 12 per cent above its 2006−07 level, the average over the next regulatory control period is 9 per cent above, and by 2013−14 it is 8 per cent above.[1322]

Based on this assessment, Wilson Cook concluded that Country Energy's 2006−07 opex represents an efficient level, even though it deferred work associated with meeting its licence conditions. While Wilson Cook acknowledged the increase in expenditure from the start of the next regulatory control period, Wilson Cook considered the increase to be reasonable (in light of the requirement to meet the licence conditions on individual feeder reliability).[1323]

AER considerations

While acknowledging the limitations of the benchmarking exercise, the AER accepts that it provides some measure of whether the base year from which opex is forecast is representative of efficient expenditure by Country Energy.

The AER also considers that where the proposed base year actual expenditure is close to or less than the efficient allowance provided in the previous regulatory determination, it is reasonable to accept the base year as an efficient starting point. The AER notes that Country Energy's actual opex for 2006−07 is very close to the corresponding forecast value provided in the current IPART determination. However, as noted by Wilson Cook, the forecast opex in the IPART determination includes a significant cost pass through amount for works which Country Energy indicated it chose to defer to the next regulatory control period.

On 1 August 2005, the NSW Minister for Energy imposed additional conditions on Country Energy's operating licence under the *Electricity Supply Act 1995* (NSW) relating to design, reliability, and performance of electricity distribution network (licence conditions).[1324]

In December 2005 Country Energy lodged a general cost pass through application with IPART, for the incremental capital and operating costs relating to the imposition of the licence conditions.

IPART accepted Country Energy's application and provided additional capex and opex for the remainder of the current regulatory control period to 2008−09, for activities including:[1325]

1321 Wilson Cook, volume 4, pp. 37–38.
1322 Wilson Cook, volume 4, p. 38.
1323 Wilson Cook, volume 4, p. 39.
1324 IPART, *NSW Distribution Network Cost Pass Through Review − Statement of Reasons for decision*, 5 May 2006, p. 2.
1325 IPART, *NSW Distribution Network Cost Pass Through Statement of Reasons*, p. 1.

- augmentation of individual subtransmission powerlines that exceeded the n−1 criteria for loads greater than or equal to 15 MVA

- augmentation of urban distribution feeders that did not comply with the n−1 in the major regional centres

- implementation of a suite of maintenance and capital investment initiatives forming part of a reliability remediation program for 95 poor performing feeders segments per annum at an average cost per feeder segment of around $1.2 million.

The opex component of that cost pass through allowance is provided in table O.3.

Table O.3: Country Energy's opex pass through ($m, 2008–09)

	2006–07	2007–08	2009–09	Total
IPART approved pass through	45	45	45	135

Source: IPART, *NSW Distribution Network Cost Pass Through Review − Statement of Reasons for decision*, 5 May 2006.

Country Energy indicated in its regulatory proposal that it chose to defer all of this opex to the next regulatory control period.[1326] As a result, the 2006−07 IPART determination opex allowance and Country Energy's actual opex for that year are not strictly comparable. Country Energy's 2006−07 base year opex is above the IPART determination since the 2006−07 allowed opex took account of specific services (enhanced vegetation management for poor performing feeder segments) that Country Energy did not undertake and instead chose to defer. Effectively, in the absence of the IPART pass through allowance, Country Energy would have overspent the IPART opex allowance for 2006−07 by $42 million ($2006−07).

Country Energy indicated that the decision to defer the work program reflected a number of issues, including:[1327]

- an underestimation of the vegetation management required for the current regulatory control period

- increasing cost pressures arising from a number of changes in cost structure

- expenditure pressures resulting from what it considered was an unsustainable regulatory expenditure allowance in the 2004 IPART determination

- an increasing need to spend additional capital for the construction of critical infrastructure, which necessitated a re-allocation of internal resource effort away from opex and towards capex.

The AER acknowledges that there have been cost pressures during the current regulatory control period and notes Wilson Cook's comments that:

[1326] Country Energy, *Regulatory proposal*, p. 35.
[1327] Country Energy, *email to AER*, 21 July 2008.

- at the time of the last determination, Country Energy was a relatively new organisation and may not have had the systems and knowledge to justify an appropriate level of expenditure

- Country Energy's position in the comparative analysis and its over expenditure in the current regulatory control period relative to the determination (excluding the allowance for cost pass through) suggest that the level of opex allowed for in the current period may not have been sufficient for it to undertake a prudent level of work.

Accordingly, the AER will accept Wilson Cook's advice that Country Energy's 2006−07 opex represents an efficient base year from which to forecast its future opex requirements.

The AER considers that Wilson Cook's assessment of Country Energy's base year opex largely addresses the EUAA's concern regarding the large step increase between opex in the current and next regulatory control periods.

Based on Wilson Cook's advice the AER is satisfied that Country Energy's base year is representative of efficient expenditure from which to project its forecast opex requirements.

O.4.3 Network opex

Country Energy indicated that this expenditure category is an overhead item. Country Energy advised that business and technical overheads were allocated mainly to maintenance and capital activities and that the costs shown under this category comprised the balance not so allocated.

Country Energy proposal

Table O.4 shows Country Energy's forecast network opex in the next regulatory control period.

Table O.4: Country Energy's forecast network opex ($m, 2008–09)

	2009−10	2010−11	2011−12	2012−13	2013−14	Total
Network operating	17.7	17.7	17.9	18.2	18.5	89.9

Source: Country Energy, *Regulatory proposal*, p. 63.

Network opex in the next regulatory control period is $90 million, compared with $123 million in the current regulatory control period, a decrease of 27 per cent. Network operating costs account for approximately 4 per cent of Country Energy's total opex for the period.

Country Energy indicated that the reduction in expenditure arose from a change in the method of allocation, with more overheads allocated to direct expenditure categories.

Consultant review

Wilson Cook accepted Country Energy's network opex forecast without adjustment.

AER considerations

The AER notes the forecast network operating costs were derived using labour cost escalators and CPI escalators for non-labour components. The cost escalators are subject to adjustment, as noted in chapter 8 and appendix N of this draft decision, and hence the forecasts for network opex will vary from that proposed by Country Energy.

The AER notes that the forecast costs under this item in the next regulatory control period are significantly lower than the current regulatory control period. Based on Wilson Cook's advice, the AER considers that Country Energy's proposed network opex (with adjustments to the cost escalators) reflects the efficient costs that a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives.

O.4.4 Network maintenance expenditure

Country Energy indicated that network maintenance expenditure relates to the requirement to provide a safe network, to meet regulatory obligations and to meet customer requirements for network quality and reliability.

Country Energy proposal

Table O.5 shows Country Energy's forecast network maintenance expenditure for the next regulatory control period.

Table O.5: Country Energy's forecast network maintenance expenditure ($m, 2008–09)

	2009−10	2010−11	2011−12	2012−13	2013−14	Total
Inspection	38.3	39.2	40.4	41.8	43.2	202.9
Pole replacement	2.2	2.3	2.3	2.4	2.5	11.8
Maintenance and repair	67.7	69.2	71.4	73.9	76.5	358.7
Vegetation management	105.1	108.0	112.3	117.3	122.7	565.3
Emergency response	48.0	48.2	48.8	49.7	50.1	245.3
Other network maintenance	83.8	85.6	88.3	91.4	94.6	443.8
Total network maintenance	345.1	352.5	363.5	376.5	389.6	1827.8

Source: Country Energy, RIN.
Note: Totals may not add up due to rounding.

Country Energy forecast maintenance expenditure in the next regulatory control period of $1828 million, compared with $1167 million in the current regulatory control period, which is an increase of 57 per cent. Maintenance costs account for approximately 87 per cent of Country Energy's total opex for the next regulatory control period. Average annual expenditure over the next regulatory control period is $366 million, 49 per cent above the base year level.

O.4.4.1 Maintenance policies and processes

Country Energy proposal

Country Energy's maintenance strategy is outlined in its network asset management plan and various other policy documents. Country Energy indicated that it recently reviewed in detail all its inspection, vegetation control, maintenance and renewal management policies, procedures, and practices. At the same time, new strategic plans and work programs have been developed based on risk management techniques. This is to ensure that inspection, vegetation and maintenance issues relating to system assets, which may adversely impact on public and employee safety, supply interruption, financials, exposure to litigation, environment, and reputation are identified, assessed, and mitigated to acceptable levels.[1328]

Country Energy then prepared a work plan based on the work tasks identified and prioritised from the risk assessment. Each work task was then costed using unit rates and quantities.[1329]

Consultant review

Wilson Cook reviewed the asset management plans and policies and the principles applied to the risk-based model used to derive the work program and indicated that the:

- maintenance strategies and processes used by Country Energy were typical of electricity distribution businesses
- inspection cycles and routine maintenance activities were in line with industry standards
- process used to review and identify maintenance requirements appeared to be robust and appropriate.

Based on its review, Wilson Cook concluded that it was satisfied that Country Energy's maintenance policies and processes were appropriate and properly applied.[1330]

AER considerations

The AER considers that the implementation of inspection, condition monitoring, and vegetation control and maintenance strategies is crucial to the ongoing effective operation of a distribution network. Country Energy's asset maintenance management plan documents the asset plans, strategies, work programs, and future expenditure requirements for each asset class and equipment category to 2013–14.

Based on the AER's review of Country Energy's asset maintenance management plan and Wilson Cook's advice, the AER considers that the maintenance policies and

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[1328] Country Energy, *Regulatory proposal*, p. 49.
[1329] Country Energy, *Regulatory proposal*, p 50.
[1330] Wilson Cook, volume 4, pp. 39–40.

process adopted by Country Energy are consistent with those used by other DNSPs and represent good industry practice.

O.4.4.2 Inspection, maintenance and repair, and vegetation management[1331]

Country Energy proposal

Inspection expenditure

Opex associated with inspections in the next regulatory control period accounts for 11 per cent of Country Energy's total maintenance opex forecast. Average annual expenditure over the next regulatory control period is $41 million, which is 92 per cent above the 2006−07 base year level.

Country Energy indicated that the increases in inspection have been driven by step increases of $9.9 million per annum for deferred programs of work and $4.1 million per annum for new programs.[1332]

Country Energy stated over 80 per cent of the deferred program relates to feeder reliability improvement inspection programs provided as part of the IPART cost pass through allowance. This includes live line pole-top inspection of poor performing feeder segments and annual aerial patrol and photography of poor performing feeders. This reflects the focus in the licence conditions on improving the reliability of each DNSP's worst performing feeders.[1333]

The new programs proposed by Country Energy include new initiatives to widen the scope of the inspection program, including: [1334]

- programmed internal inspection of all underground pits and pillars
- six-monthly condition monitoring of critical distribution substations and ring main units
- programmed live-line pole-top inspection of all radial sub–transmission feeders
- a 'thermo vision' program covering all critical equipment and urban network components
- six-monthly condition monitoring of all regulators and re-closers.

Maintenance and repairs expenditure

Expenditure on maintenance and repairs in the next regulatory control period accounts for 20 per cent of Country Energy's total maintenance budget. Average annual expenditure over the period is projected to be $72 million, which is 69 per cent above the base year level.

1331 For the purposes of the AER's assessment these opex categories have been combined. This reflects the common issues associated with each of these opex categories.
1332 Country Energy, presentation to AER and Wilson Cook, 7 July 2008, pp.197–199.
1333 Country Energy, *Regulatory proposal*, p. 54; presentation to AER and Wilson Cook, 7 July 2008.
1334 Country Energy, *Regulatory proposal*, p. 53.

Country Energy indicated that there is a proposed step increase of $23 million per annum of which 39 per cent is for a reduction in the maintenance backlog, 29 per cent is for deferred programs and 32 per cent is for new programs.[1335]

Vegetation management expenditure

Expenditure on vegetation management in the next regulatory control period accounts for 31 per cent of Country Energy's total maintenance budget. Average annual expenditure over the next regulatory control period is $113 million, which is 150 per cent above the base year level.

Country Energy applied a higher real cost escalation to vegetation management expenditure than to other activities due to the high labour content of this work. It also applied an asset growth escalator to vegetation management to reflect the relationship between growth capex and vegetation management.[1336]

Country Energy indicated that it underestimated the vegetation management required for the current regulatory control period and although it had deferred programs that it put forward for its 2005 cost pass through application to IPART, it had spent more than the total allowed for vegetation management during the current regulatory control period.

Country Energy stated that the increased cost pressures arising from a number of changes in cost structure, and the expenditure pressures resulting from an unsustainable regulatory expenditure allowance in the 2004 IPART determination, contributed to the deferral of works and to a mounting backlog of asset inspection, testing and risk defect maintenance work.[1337]

In addition, Country Energy indicated that during the current regulatory control period, there had been an increasing need to spend additional capital for the construction of critical infrastructure, which had necessitated a re-allocation of internal resource effort away from operations and maintenance of the network and toward the capex program.[1338]

Country Energy indicated that the provision of additional expenditure for the deferred and backlog programs is considered appropriate in order to permit Country Energy to better manage current and ongoing maintenance backlog, comply with feeder reliability licence conditions and the maintenance requirements associated with an ageing asset base in order to mitigate risk and safety issues.[1339]

1335 Country Energy, *Regulatory proposal*, p. 64.
1336 Country Energy, *Regulatory proposal*, p. 47.
1337 Country Energy, *Regulatory proposal*, p. 39.
1338 Country Energy, email to AER, 21 July 2008.
1339 Country Energy, email to AER, 21 July 2008.

Consultant review

Inspection expenditure

Wilson Cook considered the increased scope of the proposed programs to be reasonable and that the programs would enable Country Energy to identify risks earlier and improve system performance.[1340]

Maintenance and repairs expenditure

Wilson Cook indicated that the forecast annual expenditure on maintenance and repair activities was not excessive for the size of Country Energy's network asset base and therefore considered the proposed level of expenditure to be reasonable.[1341]

Vegetation management

Wilson Cook indicated that Country Energy had provided it with a comparison that had been undertaken with Ergon Energy's vegetation management expenditure.[1342] The comparison showed that Ergon Energy had a similar profile of vegetation density and that after allowing for differences in cycles and size, Country Energy's proposed expenditure was comparable to that incurred by Ergon Energy.

Wilson Cook reviewed all the information provided on the vegetation management forecast and noted that much of the increased program is new and targeted at different purposes to the historical program. Wilson Cook indicated that it will take some years before it can be established that the program achieves the reliability improvements being targeted but use of the profiling data would provide a reasonable basis for estimating the required works.

Wilson Cook did not consider that it was appropriate to apply the asset growth escalator to vegetation management, as it was unlikely that the quantity of work in this area would be driven principally by growth capex. Wilson Cook therefore recommended an adjustment to remove this from the proposed expenditure, resulting in a total reduction of $30 million over the regulatory control period.[1343]

AER considerations

Deferred vegetation management

The AER has concerns with the deferral of opex programs that Country Energy had previously put forward in justification of its cost pass through application to IPART in 2005. As noted above, IPART accepted Country Energy's cost pass through application and provided Country Energy with $135 million ($2008−09) to complete a number of activities in relation to the imposition of new licence conditions. Country Energy indicated that it chose not to proceed with these nominated work programs in the current regulatory control period, and instead directed those funds to other work programs.

[1340] Wilson Cook, volume 4, p. 40.
[1341] Wilson Cook, volume 4, p. 40.
[1342] The Ergon Energy distribution network is considered by Wilson Cook to be the most comparable Australian distribution network to the Country Energy network.
[1343] Wilson Cook, volume 4, p. 41.

In the absence of this cost pass through allowance Country Energy would have substantially over spent its regulatory allowance during the current regulatory control period. Based on information provided by Country Energy, in the absence of the cost pass through allowance, expenditure in the current regulatory period would be $135 million higher than that provided in the IPART determination (i.e. the amount of the proposed cost pass through work program that Country Energy chose to defer).[1344]

Country Energy is now requesting those deferred programs be included in the next regulatory control period. By proposing the reinstatement of this deferred opex, Country Energy is, in effect, seeking an allowance of $135 million which has already been provided for during the current regulatory control period.

The AER has decided not to allow Country Energy to recover the deferred opex in the next regulatory control period. In determining whether the AER is satisfied that the forecast opex reasonably reflects the efficient costs a prudent operator in the circumstances of the DNSP would require to meet the opex objectives, the AER must have regard to the factors set out in clause 6.5.6(e). Clause 6.5.6(e)(5) allows the AER to consider the actual and expected expenditure of a DNSP in the current regulatory control period. In considering the expenditure during the current regulatory control period, the AER notes that Country Energy has already received an allowance to undertake the enhanced vegetation management for poor performing feeder segments program of works. The AER is therefore not satisfied that Country Energy's opex forecast reflects the efficient costs that a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives.

First, the costs of meeting the opex objectives would not allow Country Energy to receive an allowance for activities for which it has previously received an allowance, because this would not reflect an efficient outcome. Second, the AER is required to consider a prudent operator in the circumstances of Country Energy, which includes the fact that Country Energy has already received an allowance for the enhanced vegetation management for poor performing feeder segments activity. Taking this into account, the AER considers that a prudent operator in the circumstances of Country Energy should not require this allowance again.

Although the AER's decision has been made based on the considerations set out above, the AER notes the financial consequence of Country Energy deferring the activities provided for in the cost pass through approved by IPART was to limit an overspend Country Energy would have incurred. Hence its operating surplus was greater than it otherwise would have been and the impact on the business of expenditure exceeding the regulatory allowance was removed. While the AER notes the associated expenditure is needed, it is of the view that where customer charges are increased to finance a specific activity in the current regulatory control period, then charges should not be again increased to deliver that service. It would appear more appropriate that this cost be met in the same way as it would if Country Energy had exceeded its regulatory allowance in the current regulatory control period.

The AER also notes that this is consistent with maintaining incentives in the regulatory framework for DNSPs to pursue operating cost efficiencies. Any ex-post

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[1344] Country Energy, emails to AER, 24 October 2008 and 28 October 2008.

adjustment weakens the incentive effects of the regulatory regime and undermines the regulatory contract between customers and the DNSP. In that respect, the regulatory framework would be effectively operating as a cost-plus regime and Country Energy (and other DNSPs) would see few benefits from reducing its opex since it would bear none of the financial risk of higher expenditures.

Further, the AER notes that the decision to deny the recovery of Country Energy's past opex implicit overspend is consistent with that adopted by IPART in the previous regulatory reset.[1345]

Based on the decision set out above the AER has removed the deferred expenditure forecasts from Country Energy's opex forecasts for the next regulatory control period. Using the profile of expenditure provided by Country Energy, the AER's adjustments to Country Energy's opex forecasts are set out in table O.6.

Table O.6: AER's adjustments to Country Energy's opex forecast for deferred works ($m, 2008–09)

	2009−10	2010−11	2011−12	2012−13	2013−14	Total
Inspection	–6.2	–6.2	–6.2	–	–	–18.6
Maintenance and repair	–3.0	–3.0	–3.0	–	–	–9.0
Vegetation management	–35.9	–35.9	–35.9	–	–	–107.7
Total adjustments	–45.1	–45.1	–45.1	–	–	–135.3

Note: Totals may not add up due to rounding.

Vegetation management escalation

Country Energy developed an escalator to reflect the relationship between growth in the network and real increases in opex. Country Energy argued that growth related capex increases the size of the network and the number of assets to be maintained, operated and managed. Country Energy further suggested that vegetation management increased in response to network growth. To capture this relationship, Country Energy applied its growth related escalation factor to vegetation management.

The AER agrees with Country Energy that there is a positive relationship between network growth and opex. However, the AER accepts Wilson Cook's advice that it is unlikely that growth capex is the key driver of the quantity of vegetation management required. The AER considers that vegetation management is likely to more heavily influence by service quality issues and compliance with licensing and other requirements.

Based on its own assessment and Wilson Cook's advice, the AER considers that Country Energy's vegetation management expenditure for the next regulatory control period should be adjusted to reflect the efficient costs of a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives, as required by clause 6.5.6(c). The AER's adjustment relates to the removal of the asset

[1345] IPART, *NSW Electricity Distribution Pricing Final Report*, p. 50.

growth escalator applied by Country Energy. Following a request from the AER Country Energy advised that the AER's conclusion results in a reduction of $25 million to its forecast opex.[1346]

O.4.4.3 Emergency response

Emergency response covers fault and emergency repair and restoration of supply for planned and unplanned interruptions caused by events such as storms, equipment failures, acts of vandalism, and vehicle collisions.

Country Energy proposal

Expenditure on emergency response in the next regulatory control period accounts for 13 per cent of Country Energy's total maintenance opex. Average annual expenditure over the next regulatory control period is $49 million, which is 10 per cent below the base year level.

Country Energy indicated that it included a reduction in emergency response expenditure to reflect the increased reliability capital program. Country Energy indicated that it is expected that the increase in reliability expenditure is expected to lead to offsetting improvements in the current level of fault and emergency work on the network.[1347]

Consultant review

Wilson Cook recommended the acceptance of Country Energy's emergency response expenditure forecast for the next regulatory control period. Wilson Cook noted that Country Energy included a reduction in emergency response expenditure to reflect expected benefits from Country Energy's reliability-related capex program. Wilson Cook concluded that this adjustment was appropriate.[1348]

AER considerations

The AER has reviewed Country Energy's proposed emergency response expenditure estimates and the methodology used to derive them. It considers that the methodology is robust but notes that the conclusions on labour cost escalators set out in appendix N will impact on these forecasts.

The AER notes that Country Energy's proposed emergency response expenditure for the next regulatory control period is very similar to that in the current regulatory control period. In addition, the AER considers that Country Energy has taken adequate account of its reliability-related capex program in developing its emergency response forecast. Country Energy indicated that its asset refurbishment, renewal and vegetation management projects are designed to improve the reliability and security of electricity supplies, hence Country Energy has included a saving of $15 million to offset its emergency response expenditure over the period.

Based on the AER's assessment and Wilson Cook's advice, the AER considers that Country Energy's proposed emergency response expenditure (with adjustments to the

[1346] Country Energy, response to information request, confidential, 17 November 2008.
[1347] Country Energy, *Regulatory proposal*, p. 55.
[1348] Wilson Cook, volume 4, p. 36.

cost escalators) reflects the efficient costs that a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives.

O.4.4.4 Other network maintenance

Other network maintenance covers insurance premiums for network assets, public liability and employee related insurance costs. It also includes other fire mitigation work, field training, and other costs to support the maintenance function. This category also includes costs associated with Country Energy's service delivery business unit. This unit is responsible for undertaking and completing the annual asset inspection and maintenance program, investigating and rectifying system faults, and administrative support for maintenance and repair activities including the management of contracts related to external service providers.

Country Energy proposal

Expenditure on other network maintenance in the next regulatory control period accounts for 24 per cent of Country Energy's total maintenance opex. Average annual expenditure over the next regulatory control period is $89 million, which is 13 per cent above the base year level. The increase in expenditure is explained by cost and growth escalation.[1349]

Consultant review

Taking into account historical expenditure levels and projected work levels over the next regulatory control period, Wilson Cook indicated that Country Energy's other network maintenance forecasts were reasonable and recommended accepting the forecasts without amendment.[1350]

AER considerations

The AER notes that the conclusions on cost escalators set out in chapter 8 and appendix N will impact on these forecasts.

The AER also notes that this category of opex includes no step changes, rather the increase in expenditure over the next regulatory control period reflects the application of cost and growth escalators. The AER reviewed the activities included in this expenditure category and agrees that these are likely to be impacted by cost increases and network growth. Based on this assessment and Wilson Cook's advice, the AER considers that Country Energy's other network maintenance expenditure (with adjustments to the cost escalators) reflects the efficient costs that a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives.

O.4.5 Other operating costs

Other operating costs include Country Energy's share of business support functions such as customer services, customer call centres, metering reading and data services for type 5−7 meters, billing and revenue management, and other corporate support functions.

[1349] Country Energy, *Regulatory proposal*, pp. 48–49.
[1350] Wilson Cook, volume 4, p. 41.

Country Energy proposal

Table O.7 shows Country Energy's forecast other opex expenditure for the next regulatory control period.

Table O.7: Country Energy's forecast other operating costs ($m, 2008–09)

	2009−10	2010−11	2011−12	2012−13	2013−14	Total
Meter reading	19.2	19.6	20.3	21.0	21.7	101.8
Customer service	13.4	13.7	14.2	14.7	15.2	71.2
Advertising, marketing and promotions	4.8	4.9	5.1	5.3	5.4	25.5
Total	37.4	38.2	39.6	41.0	42.3	198.5

Source: Country Energy, *Regulatory proposal*, p. 63.
Note: Totals may not add up due to rounding.

Other operating costs in the next regulatory control period are forecast at $198 million compared with $201 million in the current regulatory control period, a decrease of 1 per cent. Other operating costs account for approximately 9 per cent of Country Energy's total opex forecast for the next regulatory control period.

Consultant review

Wilson Cook noted that forecast costs are at a similar level to the current regulatory control period. In addition, cost escalation has been offset by a reduction in the allocation of overheads to these categories. Wilson Cook concluded that there was no need for an adjustment to the forecast other operating costs.[1351]

Wilson Cook noted that, the methodology for allocating technical and business overheads was amended during the current regulatory control period. Technical and business overheads are now allocated to opex and capex based on ordinary and overtime labour, rather than the past method which used ordinary labour only. This resulted in expenditure categories where overtime forms a major component of total expenditure, such as emergency response, receiving a larger share of technical and business overheads.

AER considerations

The AER notes Wilson Cook's review found that the proposed other operating costs are reasonable. However, the conclusions on cost escalators set out in chapter 8 and appendix N will impact on these forecasts.

Based on Wilson Cook's advice, the AER considers that Country Energy's forecast opex for operating costs (with adjustments to the cost escalators) reflects the efficient costs that a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives.

[1351] Wilson Cook, volume 4, p. 42.

O.5 AER conclusion

The AER has decided to adjust Country Energy's forecast controllable opex for the next regulatory control period. Country Energy's forecast controllable opex and the AER's adjustments are set out in table O.8. The AER considers that reducing the opex forecast by $165 million would reflect the efficient costs that a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives.

The AER notes Country Energy's forecast controllable opex was derived using labour cost escalators for the labour component and CPI (and oil) escalators for non-labour components. The labour and oil cost escalators are subject to adjustment, as noted in chapter 8 and appendix N of this draft decision, and hence the forecast controllable opex will be further adjusted.

Table O.8: AER's adjustments to Country Energy's forecast controllable opex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy's proposed controllable opex	400.3	408.4	420.9	435.4	451.0	2116.0
Adjustment for deferred expenditure						
Inspection	–6.2	–6.2	–6.2	–	–	–18.6
Maintenance and repair	–3.0	–3.0	–3.0	–	–	–9.0
Vegetation management	–35.9	–35.9	–35.9	–	–	–107.7
Adjustment for vegetation management escalation	–1.2	–2.4	–3.8	–7.7	–10.2	–25.3
Total adjustments	–46.3	–47.5	–48.9	–7.7	–10.2	–160.6
AER's adjusted controllable opex	354.0	360.9	372.0	427.7	440.8	1955.4

Note: Totals may not add up due to rounding. The AER's adjusted controllable opex has not yet been adjusted for labour and oil cost escalators.

Appendix P: EnergyAustralia controllable operating expenditure

EnergyAustralia's regulatory proposal included both its transmission and distribution network requirements. The transitional chapter 6 rules provide that the AER is required to make a single determination for EnergyAustralia's transmission and distribution assets. Although EnergyAustralia provided separate tables for distribution and transmission as part of its regulatory proposal, all supporting information is based on its opex requirements in total. The analysis of opex has therefore been undertaken in total, rather than attempting to consider forecast opex by distribution and transmission separately.

P.1 EnergyAustralia proposal

EnergyAustralia's proposed controllable (core) opex in the next regulatory control period compared with that in the current regulatory control period is shown in table P.1.[1352]

Table P.1: EnergyAustralia's controllable opex by category ($m, 2008–09)

	Actual			Estimated		Proposed				
	04–05	**05–06**	**06–07**	**07–08**	**08–09**	**09–10**	**10–11**	**11–12**	**12–13**	**13–14**
Network operating	90	91	106	140	163	183	189	191	196	199
Network maintenance	165	173	190	198	210	220	226	237	248	261
Other expenditure	104	158	79	137	143	155	159	165	172	172
Total	358	423	374	474	516	558	574	593	616	632

Source: EnergyAustralia, RIN.
Note: Totals may not add up due to rounding.

The total controllable opex proposed in the next regulatory control period is $2973 million compared with an estimated $2145 million in the current regulatory control period, an increase of 39 per cent.

In response to a number of issues raised by Wilson Cook, EnergyAustralia undertook further analysis in relation to the relationship between capex and maintenance expenditure. As a result of this analysis, EnergyAustralia's forecast network maintenance expenditure was reduced by $19 million. EnergyAustralia also advised that it identified errors in its asset age profile information which further reduced its opex forecast by $4 million. The adjusted maintenance expenditure forecasts and the consequent updated opex forecasts for the next regulatory control period are provided in table P.2.

[1352] EnergyAustralia's total controllable opex reported in its regulatory proposal includes self insurance but excludes debt and equity raising costs.

Table P.2: EnergyAustralia's adjusted controllable opex by category ($m, 2008–09)

	2009−10	2010–11	2011–12	2012–13	2013–14	Total
Network operating	182.7	189.1	190.8	196.1	198.6	957.3
Network maintenance	217.7	222.7	231.8	242.6	252.4	1167.3
Other expenditure	155.3	159.2	165.1	172.2	172.4	824.2
Total	555.8	571.1	587.6	610.9	623.4	2948.8

Source: Wilson Cook, volume 2, pp. 53, 56, 58, 61.
Note: Totals may not add up due to rounding.

The total controllable opex proposed after the adjustment in the next regulatory control period is $2949 million compared with an estimated $2145 million in the current regulatory control period, an increase of 37 per cent.

EnergyAustralia indicated that the reasons for the increased level of expenditure over the next regulatory control period include:[1353]

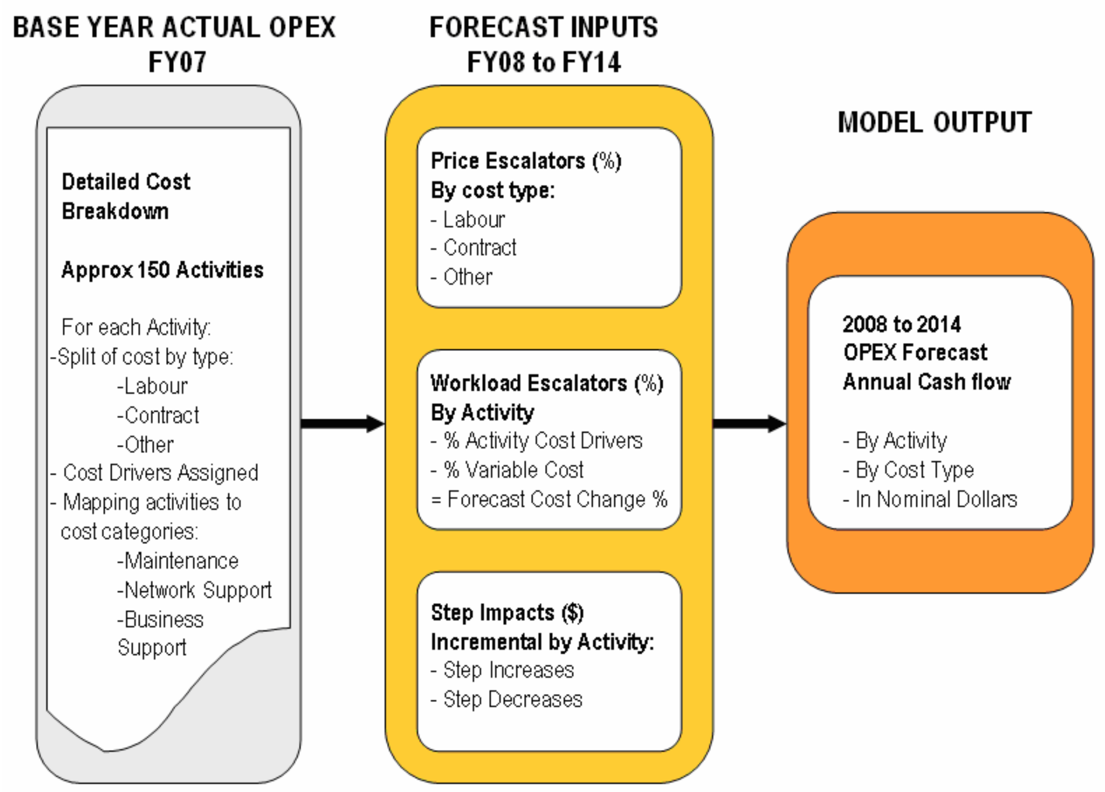
- increased workload largely arising from the larger asset base, adding approximately 25 per cent to direct maintenance costs
- increased workload due to the increasing age of network assets
- cost increases above inflation
- step changes arising partly from the higher costs of IT from the introduction of new and partly from a need to meet statutory and regulatory obligations.

P.1.1 Opex forecasting methodology

EnergyAustralia forecast its opex by defining base year opex and applying an escalation factor based on price and volume escalators (using key inputs and assumptions) on all 150 activities of its base year expenditure. Figure P.1 shows an overview of EnergyAustralia's opex forecasting approach.

[1353] EnergyAustralia, *Regulatory proposal*, p. 8.

Figure P.1: EnergyAustralia opex forecasting approach



Source: EnergyAustralia, Opex presentation to the AER and Wilson Cook, 30 June 2008, slide 5.

The forecast opex is built up on a bottom-up basis from the 2006–07 efficient base (fixed and variable) cost at the activity level. This is then escalated based upon:

- workload escalation factors
- price escalation factors
- step changes.

In summary, the total forecast operating cost for EnergyAustralia is the sum of the cost forecasts for all of the network activities performed by each business unit for the particular year.

P.1.2 Components of forecast opex

Efficient base year controllable costs

EnergyAustralia used its 2006−07 opex as a starting point for future projections of operating costs. EnergyAustralia indicated that, not only is 2006−07 the most recent full year of audited accounts, it is the first year during which backlogs of preventative maintenance have been fully completed, and is also the first complete year that reflects the impact of EnergyAustralia's pass through claim in 2005.[1354]

Impact of external factors

EnergyAustralia indicated that it has not incorporated any specific costs that are directly attributed to meeting any new or future obligations within the opex program, apart from the impact on opex of the increased capex program that is partly driven by the need to comply with EnergyAustralia's licence conditions.

Proposed step changes

EnergyAustralia factored in a large number of step changes to its level of base year opex. Most of these occur between the base year and the start of the next regulatory control period. Excluding adjustments for abnormal items in 2006−07, the step changes total $64 million.[1355]

EnergyAustralia notes that it has used the term 'step change' to identify systematic changes in costs that are on-going (i.e. recurrent costs). This term does not equate to 'one-off change'.[1356]

The effect of the step changes is to add approximately 15 per cent to the average opex for the next regulatory control period as compared to the base year.

Escalators

EnergyAustralia engaged Competition Economists Group (CEG) to determine escalation trends in labour and material costs for the current and future regulatory control periods.

EnergyAustralia applied the industry specific electricity and gas workers cost index for labour in its network and contracting business units and the general wage index has been applied to labour in its corporate and shared services business units, contracted services such as meter reading and IT and tree trimming. EnergyAustralia stated that it had not applied real cost escalators to any other cost inputs for opex.[1357]

EnergyAustralia indicated that it applied 18 months of cost escalation between the 2006–07 base year and 2007–08 on the basis that the average 2006–07 year dollars are effectively December 2006 rates and the AER requires inputs to be in real June year dollars.[1358]

The effect of real cost escalation from the 2006–07 base year adds approximately 12 per cent to opex for the next regulatory control period.

[1354] EnergyAustralia, *Regulatory proposal*, p. 127.

[1355] The abnormal items include the effects of significant additional expenditure as a result of the 2007 June long weekend storms that resulted in wide spread flooding and network damage in the Newcastle and Central Coast regions, a superannuation rebate and an accounting change relating to fleet and logistics recoveries.

[1356] EnergyAustralia, *Response to submissions on EnergyAustralia's regulatory proposal*. October 2008, p. 11.

[1357] EnergyAustralia, *Regulatory proposal*, p. 131.

[1358] EnergyAustralia is the only NSW DNSP to escalate by 18 months. The other NSW DNSPs escalated the base year by 12 months.

EnergyAustralia also used workload escalators (drivers) to account for the change in volume in each work activity from the base year. Workload escalation has been applied only to the variable element of costs.[1359]

The impact of applying the workload escalation to the normalised base year adds approximately 9 per cent to the average opex for the next regulatory control period as compared with the base year.

Capex/opex trade off

EnergyAustralia addressed the capex/opex trade off in terms of the impact of replacement capex on opex. EnergyAustralia observed that, other things being equal, the level of maintenance expenditure needed on a network will increase as the network ages.[1360]

EnergyAustralia produced a graphical relationship between maintenance expenditure and asset age, from which marginal additional maintenance costs can be read for given movements in the average age of the assets. Based on this relationship, EnergyAustralia calculated an increase of approximately 11 per cent in average maintenance costs over the next regulatory control period.

Productivity savings

EnergyAustralia has not allowed for any specific improvements in organisational efficiency or productivity in its regulatory proposal.

In response to submissions from the EMRF and the EUAA questioning the efficiency savings inherent in EnergyAustralia's opex forecasts, EnergyAustralia indicated that its forecasting and decision making processes are grounded in prudent considerations and motivated toward delivering efficient outcomes. This includes:[1361]

- explicit consideration of the substitution possibilities between capital and operating expenditures
- use of reliability centred maintenance forecasting approaches, which have been in place since 2004 and which have delivered significant efficiency benefits to the business during the period
- explicitly accounting for deferral benefits associated with demand management programs.

EnergyAustralia also noted that analysis conducted by SAHA International found that 'EnergyAustralia meets or exceeds best practice thresholds for asset management practices [which] ensures that maintenance programs are optimised for both cost and operational performance'.[1362]

1359 EnergyAustralia, *Regulatory proposal*, p. 112.
1360 EnergyAustralia, *Regulatory proposal*, p. 118.
1361 EnergyAustralia, *Response to submissions on regulatory proposal*, pp. 9–10.
1362 EnergyAustralia, *Response to submissions on regulatory proposal*, pp. 9–10.

EnergyAustralia indicated that it has not reduced its forecast inputs (i.e. labour) as an offsetting mechanism against productivity. Rather productivity is implicit in the forecasts provided, primarily through the use of conservative labour based cost escalators.[1363]

P.2 Submissions

The EMRF expressed concern about the accuracy of EnergyAustralia's actual opex for 2007–08. It stated that opex rose by $104 million over the previous year, an increase of 30 per cent. Further, the EMRF suggested that EnergyAustralia's claim is inconsistent with conventionally accepted criteria for a step change.[1364]

The EMRF also suggested that, given the significant increase in capex projects, the distribution businesses (especially EnergyAustralia) should be required to provide much larger efficiency savings.[1365]

The EUAA stated that EnergyAustralia had not adequately addressed the issue of efficiency savings in its regulatory proposal.[1366]

P.3 Consultant review

Wilson Cook reviewed EnergyAustralia's proposed opex from a top-down and bottom-up standpoint.[1367]

Wilson Cook concluded that the top-down analysis suggests that EnergyAustralia's base year opex is at or a little above the industry norm, but could not be considered inefficient, although there may be potential for efficiency improvements within the business. However, Wilson Cook found that EnergyAustralia's base year opex increases at a much higher rate than other ACT and NSW DNSPs. Wilson Cook indicated that unless reasons can be established why EnergyAustralia should move further away from an industry norm level of opex, then the level of opex in the next regulatory control period cannot be considered to be at an efficient level.[1368]

The bottom-up analysis identified a large number of step changes that drive large increases in expenditure. Wilson Cook found that the proposed step changes were not supported by considerations of business efficiency improvements or potential cost savings and therefore were likely to lead to a forecast of future costs that is above an efficient level. Wilson Cook therefore proposed adjustments to remove most of the step changes proposed by EnergyAustralia.[1369]

[1363] EnergyAustralia, *Response to submissions on regulatory proposal*, p. 10.
[1364] EMRF, pp. 26–27.
[1365] EMRF, p. 25.
[1366] EUAA, p. 22.
[1367] While EnergyAustralia's forecast controllable opex includes costs associated with self insurance, the efficiency and prudency of these costs was not assessed as part of Wilson Cook's review. Self insurance costs have been assessed by the AER in a separate exercise.
[1368] Wilson Cook, volume 2, p. 60.
[1369] Wilson Cook, volume 2, p. 60.

Wilson Cook indicated that the workload escalators used by EnergyAustralia were generally a reasonable representation of expected workload changes over the next regulatory control period, but recommended minor reductions in relation to maintenance escalation ($18 million) and asset management escalation ($13 million).[1370]

In total Wilson Cook recommended a reduction of $316 million (11 per cent) to EnergyAustralia's controllable opex forecast for the next regulatory control period comprising reductions in:[1371]

- network operating costs ($200 million)
- network maintenance costs ($33 million)
- other operating costs ($82 million).

Table P.3 compares the Wilson Cook recommended adjustments to EnergyAustralia's controllable forecast opex.

Table P.3: EnergyAustralia's proposed controllable opex and Wilson Cook's recommended opex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia's controllable opex forecast	555	571	588	610	624	2949
Wilson Cook's recommended controllable opex	496	508	525	545	559	2633
Difference	60	62	63	65	65	316

Source: Wilson Cook report, volume 2, p. 61.
Note: Totals may not add up due to rounding.

As a check of the recommended opex level derived from the bottom-up analysis, Wilson Cook also calculated its own top-down forecast of EnergyAustralia's opex in the next regulatory control period by applying cost escalation[1372] and size escalation[1373] to EnergyAustralia's base year opex. Wilson Cook indicated that the top-down opex forecasts were 3 per cent lower than the adjusted bottom-up level over the next regulatory control period. Wilson Cook suggested that since its benchmarking analysis indicated that EnergyAustralia was operating at or slightly above the industry norm, the top-down calculation confirms that the adjusted bottom-up level is not unreasonable.

1370 Wilson Cook, volume 2, pp. 56–58.
1371 Wilson Cook, volume 2, p. 61.
1372 This is calculated by a 60 per cent weight on the EGW labour rate and a 20 per cent weight on the general wage rate as outlined in the CEG report prepared for the NSW DNSPs.
1373 To allow for changes in the size of the business as discussed in the benchmarking section of the Wilson Cook report.

Wilson Cook provided a disaggregation of the proposed adjustments between EnergyAustralia's distribution and transmission businesses. The recommended expenditures for distribution and transmission are shown in tables P.4 and P.5 respectively.

Table P.4: Wilson Cook's recommended forecast controllable distribution opex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Network operating	130	134	137	141	144	686
Network maintenance	197	204	213	222	232	1068
Other expenditure	136	139	143	149	150	717
Total	463	476	493	512	526	2471

Source: Wilson Cook report, volume 2, p. 62.
Note: Totals may not add up due to rounding.

Table P.5: Wilson Cook's recommended forecast controllable transmission opex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Network operating	13	14	14	14	15	70
Network maintenance	14	14	13	13	13	67
Other expenditure	5	5	5	5	5	25
Total	32	32	32	33	33	162

Source: Wilson Cook report, volume 2, p. 62.
Note: Totals may not add up due to rounding.

P.4 Issues and AER considerations

P.4.1 EnergyAustralia forecasting methodology

EnergyAustralia proposal

EnergyAustralia indicated that its network opex forecasts were derived by:

- establishing actual costs by activity for the base year (2006–07). This included mapping opex activities to either maintenance costs, network support costs or business support costs
- removing abnormal costs from the base year
- applying step increases and decreases by activity
- applying projected input cost escalation factors

- applying workload cost drivers by activity including the interaction between opex and capex
- converting the model output in nominal dollars to real 2008−09 dollar terms.

Consultant review

Wilson Cook accepted the methodology proposed by EnergyAustralia, but identified a number of issues with the components of the process in particular, the step increases.[1374]

AER considerations

EnergyAustralia's forecasting methodology essentially begins with a base year and then applies cost escalators, workload escalators and step changes. The AER notes that such an approach is relatively straightforward and is consistent with that adopted by other DNSPs.

Based on the AER's assessment and Wilson Cook's advice, the AER considers that EnergyAustralia has provided a robust methodology for forecasting its opex requirement for the next regulatory control period.

Whilst accepting the overall approach, similar to Wilson Cook, the AER has identified issues associated with the components of the forecasting methodology. In particular, the AER is concerned with the number and value of step changes proposed by EnergyAustralia and the application of the growth and cost escalators. These issues are addressed below.

P.4.2 Efficient base year

EnergyAustralia proposal

EnergyAustralia used its 2006–07 operating costs as a starting point for future projections of opex. EnergyAustralia indicated that 2006–07 represented the most recent, complete and audited year of financial accounts and is the first year during which backlogs of preventative maintenance had been fully completed, and was also the first complete year that reflected the impact of EnergyAustralia's 2005 cost pass through provided by IPART.[1375]

Submissions

The EMRF is concerned about the very high start value for EnergyAustralia's opex compared to the IPART allowance. The EMRF indicated that EnergyAustralia's estimate for 2007–08 was some $90 million above the IPART allowance.[1376]

Consultant review

Wilson Cook used four measures of opex to benchmark the NSW DNSPs: opex $/size; opex $/customer; opex $/MW and opex $/km.[1377] Wilson Cook compared

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[1374] Wilson Cook, volume 2, p. 2; and letter to AER, 11 November 2008.
[1375] EnergyAustralia, *Regulatory proposal*, p. 111.
[1376] EMRF, p. 26.
[1377] Wilson Cook, volume 1, pp. 17–25.

EnergyAustralia's 2006−07 base year opex[1378] against other Australian electricity businesses in terms of opex $/size and against the predominantly urban electricity businesses in terms of opex $/customer, opex $/MW and opex $/km.[1379]

Wilson Cook concluded that the comparisons suggested that EnergyAustralia's 2006−07 opex is at or a little above the industry norm. Wilson Cook stated that EnergyAustralia's level of opex was not sufficiently at variance from the industry norm to conclude that it was inefficient, although the analysis tends to suggest that there may be potential for efficiency improvements within the business.

Wilson Cook concluded that, based on its comparative analysis, EnergyAustralia's 2006–07 opex can be considered a reasonable starting point for its future opex projections.

In addition, Wilson Cook analysed the movements in opex that have taken place or are forecast to occur in the period from 2006−07 to 2013−14 (based on opex by size). Based on this measure, Wilson Cook indicated that EnergyAustralia's expenditure in 2009−10 is 24 per cent above that in 2006−07 and is 34 per cent higher by the end of the next regulatory control period. Wilson Cook noted that the rate of increase in EnergyAustralia's opex from 2006−07 to 2009−10 is higher than that forecast by the other NSW and ACT DNSPs.[1380]

Wilson Cook also calculated an approximate labour cost escalator and used it to remove the effects of real labour cost escalation to identify the changes to EnergyAustralia's opex forecasts without it. On this basis, EnergyAustralia's 2009–10 opex per size is 15 per cent above the 2006–07 opex and stays at that level over the next regulatory control period. Wilson Cook stated that this means that over the next regulatory control period, EnergyAustralia's cost efficiency relative to the other NSW and ACT DNSPs will deteriorate. Wilson Cook indicated that unless reasons can be established why EnergyAustralia should move further away from the industry norm, then the proposed opex in the next regulatory control period cannot be considered to be at an efficient level.[1381]

In summary, Wilson Cook concluded that EnergyAustralia's base year opex is close to but a little above the industry norm and can be considered an efficient starting point for future forecasts. However, large increases in the forecast from 2006–07 to the start of the next regulatory control period mean that EnergyAustralia's forecast opex for the next regulatory control period may not be at an efficient level.

AER considerations

While the benchmarking studies only take into account EnergyAustralia's historical operating costs, the AER considers that this is relevant as it provides some measure of

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1378 Adjustments were made to the 2006–07 reported figures of all businesses to remove abnormal and one-off items. The adjustments made for EnergyAustralia changes include adding back the superannuation credit and the accounting allocations for logistics, fleet and testing and removing the impact of the 2007 storm.

1379 Wilson Cook indicated that the reported costs for EnergyAustralia exclude expenditure allocated to transmission.

1380 Wilson Cook, volume 2, p. 52.

1381 Wilson Cook, volume 2, p. 52.

whether the base year from which opex is forecast is representative of efficient expenditure by a DNSP.

In assessing the efficiency of the base year opex the AER considers that where the proposed base year actual expenditure is close to or less than the efficient allowance provided in the previous regulatory determination, it is reasonable to accept the base year as an efficient starting point for forecasting. The AER notes that EnergyAustralia's opex for 2006−07 is very similar to the corresponding forecast opex provided in the current IPART determination. On the basis that the opex allowance in the current regulatory control period is appropriate to meet network requirements, this tends to support EnergyAustralia's contention that the 2006−07 base year opex is appropriate as a starting point.

In response to the EMRF's concern regarding the relatively high start value of EnergyAustralia's forecast opex, the AER notes that the nominated base year is 2006–07 (rather than 2007-08 as suggested by the EMRF). In this respect, after adjustments for abnormals, EnergyAustralia's 2006–07 opex is very similar to the IPART allowance for that year. However, the AER notes the significant increase in opex from the base year and the Wilson Cook conclusion that EnergyAustralia may be moving outside the range of an efficient level for the next regulatory control period. This issue is discussed further in the following sections.

Based on Wilson Cook's advice the AER is satisfied that EnergyAustralia's base year is representative of efficient expenditure from which to project its forecast opex requirements for the next regulatory control period.

P.4.3 Network operating (support) expenditure

Network operating (support) expenditure refers to costs that directly support the operation of the system. Examples include operation and maintenance of network IT systems. These costs are driven by asset quantity, size of capital program, and customer numbers.

EnergyAustralia proposal

Table P.4 shows EnergyAustralia's proposed network opex for the next regulatory control period.

Table P.4: EnergyAustralia's forecast network operating expenditure ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Network control	19	19	20	21	23	102
Logistics and procurement	1	1	1	1	1	5
Insurance	6	6	6	6	6	30
Land tax	12	12	12	12	12	61
Executive management	3	3	3	3	3	15
IT planning, infrastructure and operations	59	63	62	64	66	315
Property management[a]	32	32	31	32	29	156
Training and development[b]	41	43	44	46	47	222
Other network operating	9	10	10	11	12	51
Total	183	189	191	196	199	957

Source: EnergyAustralia, RIN.
Note: Totals may not add up due to rounding.
(a) Excluding land tax.
(b) Including apprentice training costs.

Forecast network opex in the next regulatory control period is $957 million compared with $590 million in the current regulatory control period, which is an increase of 62 per cent. Network operating costs account for approximately 32 per cent of EnergyAustralia's total opex for the next regulatory control period. Average annual expenditure over the next regulatory control period is projected to be $191 million, or 80 per cent above the 2006–07 base year level.

EnergyAustralia indicated that the forecast increase was driven largely by labour cost increases, workload increases associated with an increase in numbers of assets, and increased customer numbers. The largest increases are in the subcategories of IT (average annual expenditure 101 per cent above the base year), training and development (54 per cent), property management (53 per cent), land tax (50 per cent) and network control (28 per cent).

Consultant review

Wilson Cook reviewed the workload escalators applied to network opex and considered them reasonable approximations of the increase in activity expected over the period.[1382]

Within the category of network opex, Wilson Cook indicated that there were a significant number of step changes proposed by EnergyAustralia particularly with respect to land tax, IT planning, infrastructure and operations and property management. Wilson Cook stated that these step changes accounted for around

[1382] Wilson Cook, volume 2, p. 54.

$235 million of the $957 million forecast for the network operating category in the next regulatory control period.[1383]

Wilson Cook considered that the step changes proposed by EnergyAustralia did not meet Wilson Cook's criteria for acceptable step changes.[1384] In particular, Wilson Cook considered that none of the proposed step changes meet the test of being necessitated by a fundamental change in business activity due to factors outside the control of the business. Notwithstanding the above, Wilson Cook accepted the step change for incremental apprenticeships on the basis that this is fundamental to the delivery of the proposed capital and maintenance program in the next regulatory control period. Wilson Cook removed the remaining step changes from the forecast network opex (including any cost escalation applied to the step changes).[1385] This resulted in a reduction of $200 million to EnergyAustralia's network opex forecast for the next regulatory control period, as shown in table P.5.

Table P.5: Wilson Cook's recommended forecast network operating expenditure ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia's proposal	183	189	191	196	199	957
Adjustment for step changes	–39	–42	–40	–41	–39	–200
Wilson Cook's recommendation	144	147	151	155	160	757

Source: Wilson Cook, volume 2, p. 55.
Note: Totals may not add up due to rounding.

AER considerations

The AER considers that the criteria for step changes proposed by Wilson Cook are consistent with the opex criteria in clause 6.5.6(c) of the transitional chapter 6 rules, particularly as they would ensure that step changes are limited so as to reflect the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives. In particular, the AER agrees with the requirement for a step change to deliver a benefit to customers in terms of the product delivered or to the business in terms of efficiency. The AER also notes that the EMRF expressed concern regarding the step changes proposed by EnergyAustralia and suggested that EnergyAustralia should be required to provide much larger efficiency savings.

With the assistance of Wilson Cook, the AER has assessed the veracity of the step changes proposed by EnergyAustralia for the next regulatory control period. The AER

1383 Wilson Cook, volume 2, p. 54.

1384 Wilson Cook noted that, in general, a step change should: deliver a benefit to customers in terms of the product delivered or to the business in terms of efficiency; and be non-recurring in nature or relate to a fundamental change in the business environment arising from outside factors. Wilson Cook also considered that the application by EnergyAustralia of workload escalators as well as step changes without any consideration of business efficiency improvements has the potential to over-estimate the level of future costs.

1385 Wilson Cook applied cost escalation on the assumption that the step changes being removed are 50 per cent contract and 50 per cent other costs.

also notes that efficiency gains and other savings to offset the proposed expenditure associated with the step changes are not readily apparent from the EnergyAustralia proposal.

The AER accepts Wilson Cook's advice that the criteria for accepting a step change has not been satisfied in relation to the step changes proposed by EnergyAustralia for network operating expenditure. As a result, the AER considers that the $957 million proposed by EnergyAustralia relating to its network opex exceeds the opex that would be incurred by an efficient DNSP over the next regulatory control period, and does not reflect the efficient costs required to achieve the opex objectives.

Having reviewed EnergyAustralia's proposal and the Wilson Cook assessment, the AER considers that reducing the network opex forecast for the step changes as recommended by Wilson Cook would reflect the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives. Following a request from the AER, EnergyAustralia advised that the AER's conclusion results in a reduction of $214 million to its forecast opex.[1386]

P.4.4 Network maintenance expenditure

Network maintenance expenditure includes electrical system maintenance and network control costs. These costs are driven by asset type, asset condition, the quantity of assets, and EnergyAustralia's maintenance philosophy.

EnergyAustralia proposal

Table P.6 shows EnergyAustralia's updated network maintenance expenditure forecasts for the next regulatory control period.[1387]

Table P.6: EnergyAustralia's forecast network maintenance expenditure ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Inspection	89	92	97	101	107	486
Corrective	46	47	49	51	54	246
Breakdown	44	45	47	50	53	240
Nature induced and other	9	9	10	11	11	50
Other indirect system maintenance	32	33	34	35	36	169
EnergyAustralia's adjustment	–3	–3	–4	–6	–8	–24
Total	217	223	233	242	253	1167

Source: EnergyAustralia, RIN.
Note: Totals may not add up due to rounding.

[1386] EnergyAustralia, response to information request, confidential, 20 November 2008.
[1387] As previously discussed, in response to a number of issues raised by Wilson Cook, EnergyAustralia undertook further analysis in regard to the relationship between capex and maintenance expenditure. As a result of this analysis EnergyAustralia provided updated maintenance expenditure forecasts for the next regulatory control period.

After adjustments, expenditure in the next regulatory control period is $1167 million compared with $933 million in the current regulatory control period, which is an increase of 25 per cent. Maintenance costs account for approximately 40 per cent of EnergyAustralia's total opex for the next regulatory control period. Average annual expenditure over the next regulatory control period is $233 million, or 30 per cent above the base year level after the effects of the 2007 storm are removed from the base year.

Approximately half the increase is due to real cost escalation and most of the remaining increase is due to the workload escalators. There are some minor step changes amounting to around $4 million per annum, or 2 per cent of the base level.

EnergyAustralia used a top-down approach to forecast its future maintenance expenditure and confirmed this with a bottom-up assessment of its inspection requirements.[1388]

EnergyAustralia indicated that the most significant influence on operating costs during the next regulatory control period was the proposed capital investment program (workload escalation). In the case of maintenance expenditure, EnergyAustralia noted that asset replacement has a downward influence on maintenance costs where the volume of assets replaced has a marked impact on the weighted average age of the asset class. However, where the impact of the replacement is not sufficient to prevent the weighted average age of the asset class from increasing, maintenance costs will continue to move up rather than down.[1389]

EnergyAustralia produced a graphical relationship between maintenance expenditure and asset age, from which marginal additional maintenance costs can be read for given movements in the average age of the assets. Application of this relationship resulted in an increase of approximately 11 per cent in average maintenance costs over the next regulatory control period.

Consultant review

Wilson Cook reviewed EnergyAustralia's maintenance plans and found the maintenance strategies and processes to reflect good practice in the electricity distribution industry in Australasia. However, Wilson Cook expressed doubt about the robustness of the capex/opex trade off proposed by EnergyAustralia. Wilson Cook suggested that the relationship between asset age and maintenance expenditure stated by EnergyAustralia may be overstated.[1390]

Wilson Cook noted that the relationship proposed by EnergyAustralia results in an increase of approximately 11 per cent in average maintenance costs over the next regulatory control period compared with an increase of 7 per cent that would arise if the increase was based on size (as defined by Wilson Cook).[1391] Wilson Cook noted that, based on EnergyAustralia's replacement capex in the next regulatory control period, the increase in the average age of the assets will be stemmed in that period.

1388 EnergyAustralia, *Regulatory proposal*, p. 118.
1389 EnergyAustralia, *Regulatory proposal*, pp. 116–117.
1390 Wilson Cook, volume 2, p. 55.
1391 Wilson Cook, volume 2, p. 56.

However, Wilson Cook noted that the replacement capex is directed heavily at transmission, sub–transmission and zone substation assets, not at distribution assets where it is expected that many maintenance costs lie. Taking these factors into consideration, Wilson Cook concluded that some increase in maintenance expenditure above that attributable to size alone can be expected.

In the absence of better information, Wilson Cook proposed to take as a reasonable estimate an increase half way between the increase suggested by EnergyAustralia (11 per cent) and that based on size (7 per cent)—that is, an increase of 9 per cent. This results in a reduction of $18 million to EnergyAustralia's maintenance forecast for the next regulatory control period.[1392]

Two step changes were proposed by EnergyAustralia under the maintenance expenditure category, one to adjust for an unusually low level of activity in technical publications in the base year, and the other in respect of an assessment of future claims for third party damage. These step changes account for around $15 million of the forecast maintenance expenditure for the next regulatory control period.[1393]

Wilson Cook did not consider these step changes were necessitated by a fundamental change in activity due to factors outside the control of EnergyAustralia. Wilson Cook therefore proposed an adjustment to remove the step changes. As the amounts are relatively small, Wilson Cook indicated that it had not applied cost or workload escalation to the adjustment.[1394]

Wilson Cook concluded that it was satisfied that EnergyAustralia has appropriate maintenance policies and practices but two adjustments, one to adjust the escalation due to asset ages and one to remove step changes not considered justified, were recommended. The recommended adjustments are provided in table P.7.

Table P.7: Wilson Cook's recommended forecast network maintenance expenditure ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia's proposal	217	223	233	242	253	1167
Adjustment for maintenance escalation	–3	–2	–3	–4	–6	–18
Adjustment for step changes	–3	–3	–3	–3	–3	–15
Total adjustments	–6	–5	–6	–7	–9	–33
Wilson Cook's recommendation	211	218	227	235	244	1134

Source: Wilson Cook, volume 2, pp. 56, 60.
Note: Totals may not add up due to rounding.

1392 Wilson Cook, volume 2, p. 56.
1393 Wilson Cook, volume 2, p. 57.
1394 Wilson Cook, volume 2, p. 57.

AER considerations

The AER notes that EnergyAustralia used a top-down approach to forecast its maintenance expenditure requirements for the next regulatory control period. This approach to forecasting is the same as that used in 2004.

In addition, EnergyAustralia also undertook a bottom-up assessment of its maintenance requirements involving analysis of historical numbers of completed planned inspection tasks and calculation of the associated costs per task.

The AER also note that EnergyAustralia had engaged SAHA International to benchmark its asset management performance with a focus on maintenance and that SAHA had concluded that the maintenance practices were relatively efficient. It found that 'EnergyAustralia meets or exceeds best practice thresholds for asset management practices… [and its] current asset management regime ensures that maintenance programs are optimised for both cost and asset performance.'[1395] However, the AER questions the robustness of the SAHA analysis. In particular, the AER notes the following:

- the analysis relates to opex over the 3 years to 2006–07—it is not clear that results over this period can be applied to opex forecasts over the next regulatory control period
- it is not clear that the cost categories have been suitably standardised to allow valid comparisons between businesses. In particular, it was highlighted that differences in accounting policies between businesses as a key deficiency in the study
- the sample size for opex category comparisons is relatively small (3 to 4 participants including EnergyAustralia). The small sample size makes it difficult to draw a definitive conclusion in terms of EnergyAustralia's performance.

Notwithstanding the issues with the SAHA analysis, the AER accepts Wilson Cook's conclusion that the maintenance strategies and processes reflect good practice in the electricity distribution industry in Australasia.

The AER also accepts EnergyAustralia's consideration that, other things being equal, the level of maintenance expenditure needed on a network will increase as the network ages. However, the AER notes Wilson Cook's concerns regarding the determination of the relationship between asset age and maintenance and the application of that to determine future maintenance workloads.

As discussed in relation to EnergyAustralia's network opex, the AER agrees with the criteria for step changes proposed by Wilson Cook. The AER accepts Wilson Cook's advice that the criteria have not been satisfied in relation to the step changes proposed for network maintenance expenditure.

The AER considers that the $1167 million proposed by EnergyAustralia relating to its network maintenance expenditure exceeds the opex that would be incurred by an

[1395] EnergyAustralia, *Regulatory proposal*, attachment 6.2.

efficient DNSP over the next regulatory control period, and does not reflect the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives.

Having reviewed EnergyAustralia's proposal and the Wilson Cook assessment, the AER considers that reducing the network maintenance expenditure forecast for the step changes and maintenance escalation as recommended by Wilson Cook would reflect the efficient costs that a prudent operator would require to achieve the opex objectives. Following a request from the AER, EnergyAustralia advised that the AER's conclusion results in a reduction of $31 million to its forecast opex.[1396]

P.4.5 Other operating (business support) expenditure

Other opex includes costs that relate to operation of the business itself that typically would exist in any business. These costs are related to customer numbers and staff numbers.

EnergyAustralia proposal

Table P.8 shows EnergyAustralia's proposed other opex for the next regulatory control period.

Table P.8: EnergyAustralia's forecast other operating expenditure ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Customer operations	36	37	38	40	41	192
NVD, asset management etc[a]	37	38	41	45	43	203
Divisional support	22	22	23	23	23	113
Customer support	4	4	4	5	5	22
Utilities services – metering	23	24	25	25	26	123
Debt management	1	1	1	1	1	5
Data operations	8	9	9	9	9	44
Corporate finance function	24	24	24	25	25	121
Total	155	159	165	172	172	824

Source: EnergyAustralia, RIN.
Note: Totals may not add up due to rounding.
(a) Includes network venture development, demand management, asset management, major projects & engineering and metering & connections.

Expenditure in the next regulatory control period is $824 million compared with $621 million in the current regulatory control period, which is an increase of 33 per

[1396] EnergyAustralia, response to information request, confidential, 20 November 2008.

cent. Other operating costs account for approximately 28 per cent of EnergyAustralia's total opex for the next regulatory control period.

Average annual expenditure over the next regulatory control period is $165 million per annum, or 31 per cent above the base year level after the effects of abnormal items were removed from the base year. EnergyAustralia stated that its corporate support costs have been allocated to the network business in accordance with the AER's approved cost allocation method.

Consultant review

Wilson Cook accepted the workload escalators as reasonable approximations to the increase in activity expected over the next regulatory control period, except for the use of real system capex as a driver of workload increase in the asset management and project management division. Wilson Cook did not consider that the relationship between system capex and these opex categories is as direct as assumed by EnergyAustralia or that project value is an appropriate measure of the resource required to oversee work. This is confirmed by information on staff increases that does not show growth of the same magnitude.[1397]

Wilson Cook therefore calculated an adjustment by applying an escalator based on forecast changes in the network division staff, instead of real system capex. This resulted in an adjustment of $13 million over the next regulatory control period.[1398]

As in the case with network opex, EnergyAustralia has applied a number of step changes to its base year forecast based on expected business cost changes. Wilson Cook stated that one step change—the impact of the regulatory cycle—met Wilson Cook's test of a step change. However, Wilson Cook did not consider that any of the other step changes are necessitated by a change in activities outside the control of EnergyAustralia. Wilson Cook therefore proposed an adjustment to remove these step changes (including any escalation of these costs) from the other opex forecasts.[1399]

The proposed adjustments for asset management and project management escalation and the removal of step changes are shown in table P.9.

[1397] Wilson Cook, volume 2, p. 58.
[1398] Wilson Cook, volume 2, p. 58.
[1399] Wilson Cook, volume 2, p. 59. In order to remove the impact of escalation on the step changes, Wilson Cook applied the most common workload escalator (customer numbers) and an equal ratio of the four costs escalators (EGW labour, general labour, contract and other costs).

Table P.9: Wilson Cook's recommended forecast other operating expenditure ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia's proposal	155	159	165	172	172	824
Adjustment for asset/project management escalation	–2	–2	–3	–3	–3	–13
Adjustment for step changes	–13	–13	–14	–14	–15	–69
Total adjustments	15	15	17	17	18	82
Wilson Cook's recommendation	140	144	148	155	154	742

Source: Wilson Cook, volume 2, pp. 58, 60, 61.
Note: Totals may not add up due to rounding.

AER considerations

The AER accepts the advice provided by Wilson Cook that the use of real system capex as a driver of workload increase in the asset management and project management division is not appropriate. As noted by Wilson Cook, it is not necessarily the case that large increases in EnergyAustralia's capex program will result in similar increases in costs for the supporting asset management and project management divisions—project value is not necessarily an appropriate measure of the resources required to oversee work. Wilson Cook stated that this was confirmed by information on forecast staff increases in these areas that show lower growth than the forecast growth in system capex. The AER agrees with Wilson Cook that forecast changes in the network division staff is a more appropriate escalator than increases in real system capex. As a result, the AER accepts Wilson Cook's recommended adjustment for asset/project management escalation to EnergyAustralia's other opex forecast over the next regulatory control period.

The AER also accepts Wilson Cook's advice that the criteria for accepting a step change have not been satisfied in relation to the majority of step changes proposed for EnergyAustralia's other opex. As a result, the AER accepts Wilson Cook's recommended adjustment for step changes to EnergyAustralia's other opex forecast over the next regulatory control period.

In summary, the AER considers that the $824 million proposed by EnergyAustralia relating to its other opex exceeds the expenditure that would be incurred by an efficient DNSP over the next regulatory control period, and does not reflect the efficient costs required to achieve the opex objectives. Having reviewed EnergyAustralia's proposal and the Wilson Cook assessment, the AER considers that reducing the other opex forecast for the step changes and asset/project management escalation as recommended by Wilson Cook would reflect the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives. Following a request from the AER, EnergyAustralia advised that the AER's conclusion results in a reduction of $83 million to its forecast opex.[1400]

P.5 AER conclusion

The AER previously noted that, unlike Country Energy and Integral Energy, EnergyAustralia incorporated costs associated with self insurance as part of its forecast controllable opex. The AER also noted that Wilson Cook's assessment of EnergyAustralia's forecast controllable opex did not specifically address these self insurance costs. To ensure comparability with the other DNSPs the AER has restated EnergyAustralia's forecast controllable opex with these self insurance costs removed (see table P.10).

The AER has decided to adjust EnergyAustralia's forecast controllable opex for the next regulatory control period. EnergyAustralia's forecast controllable opex and the AER's adjustments are set out in table P.10. These adjustments are the same as those recommended by Wilson Cook. The AER considers that reducing the opex forecast by $316 million would reflect the efficient costs that a prudent operator in the circumstances of EnergyAustralia's would require to achieve the opex objectives.

The AER notes EnergyAustralia's forecast controllable opex was derived using labour cost escalators for the labour component and CPI escalators for non-labour components. The labour cost escalators are subject to adjustment, as noted in chapter 8 and appendix N of this draft decision, and hence the forecast controllable opex will be further adjusted.

[1400] EnergyAustralia, response to information request, confidential, 20 November 2008.

Table P.10: AER's adjustments to EnergyAustralia's forecast controllable opex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia's proposed controllable opex	555.8	571.1	587.6	610.9	623.4	2948.8
EnergyAustralia's proposed controllable opex less self insurance costs[a]	550.0	565.2	581.8	605.1	617.6	2919.7
Adjustment for network operating	–41.2	–44.3	–42.3	–43.6	–42.5	–213.8
Adjustment for network maintenance	–4.9	–5.5	–6.1	–6.8	–7.6	–30.9
Adjustment for other expenditure	–14.9	–15.8	–17.1	–17.8	–17.3	–82.8
Total adjustments	–61.0	–65.6	–65.4	–68.2	–67.3	–327.5
AER's adjusted controllable opex	489.0	499.7	516.4	536.9	550.3	2592.3

Note: Totals may not add up due to rounding. The AER's adjusted controllable opex has not yet been adjusted for labor cost escalators.

(a) To ensure comparability with the other DNSPs, the AER has restated EnergyAustralia's forecast controllable opex with these self insurance costs removed.

Appendix Q: Integral Energy controllable operating expenditure

Q.1 Integral Energy proposal

Table Q.1 sets out Integral Energy's current and forecast controllable (core) opex by cost category and year.[1401]

Table Q.1: Integral Energy's controllable opex by category ($m, 2008–09)

	Actual			Estimated		Proposed				
	04–05	05–06	06–07	07–08	08–09	09–10	10–11	11–12	12–13	13–14
Operating and maintenance										
Inspection	14	14	15	13	14	16	16	16	17	17
Maintenance	69	78	82	93	93	102	103	106	108	110
Other operating	31	24	41	42	48	51	50	53	56	58
Corporate support	66	82	91	102	110	112	110	108	110	110
Total	179	208	230	250	265	281	280	284	290	297

Source: Integral Energy, RIN.
Note: Totals may not add up due to rounding.

Integral Energy's forecast controllable opex for the next regulatory control period is $1431 million compared with an estimated $1132 million in the current regulatory control period, an increase of 26 per cent. Integral Energy indicated that the reasons for the increased level of expenditure include:[1402]

- continued real labour cost escalation
- a step change in vegetation management contract costs
- additional apprenticeships, cadetships and graduate program placements
- an increase in the size of the asset base
- continued ageing of the asset base
- clearance of a backlog of defects.

[1401] Controllable opex is total opex less self insurance and debt and equity raising costs.
[1402] Integral Energy, *Regulatory proposal*, p. 141–142; presentation slides, 2–4 July 2008; and response to AER information request, 5 August 2008.

Q.1.1 Opex forecasting methodology

Integral Energy used a combination of escalation from base year and 'zero based' methods to forecast its opex in the next regulatory control period. Integral Energy indicated that the opex forecast is underpinned by its network and demand management strategies and the associated corporate and network planning processes.

Integral Energy stated that its network opex forecasts were derived by:[1403]

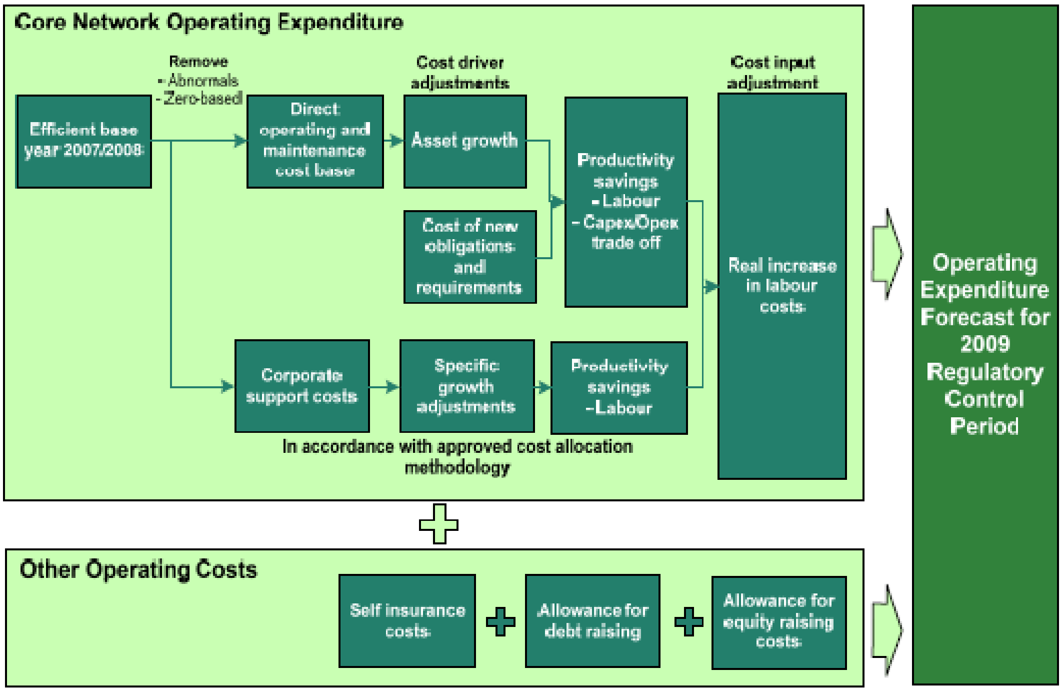
- establishing the costs for an efficient base year (2007−08)
- removing abnormal costs (and any other costs that are estimated using a zero-based approach) to establish a direct opex cost base
- adjusting direct opex for cost drivers (including growth in the asset population and the cost of new obligations)
- adjusting corporate support costs for one-off costs and for the impact of cost drivers
- applying productivity savings
- considering the interaction between opex and capex
- incorporating forecast real labour input cost increases over the next regulatory control period.

The forecast costs of self insurance and debt/equity raising costs were then added to provide total opex.

Integral Energy's opex forecasting methodology is represented in figure Q.1.

[1403] Integral Energy, *Regulatory proposal*, p. 133.

Figure Q.1: Integral Energy forecast opex process



Source: Integral Energy, *Regulatory proposal*, p. 132.

Q.1.2 Components of forecast opex

Efficient base year controllable costs

Integral Energy's forecast opex was developed using estimated values for 2007–08 as the efficient base year.[1404] Integral Energy stated that the 2007–08 year provided the best and most current representation of the costs required to deliver the service standards and obligations during the next regulatory control period.[1405]

Impact of external factors

Integral Energy proposed a step increase of approximately $5 million per annum to meet the costs of new obligations in the next regulatory control period. These include:[1406]

- a program, in conjunction with Sydney Water, to check the integrity of neutral connections in older homes ($1 million per annum)
- more pro-active assessment of neutral deterioration ($0.7 million per annum)
- additional vegetation management ($2.2 million per annum)
- generator hire to meet the licence conditions where economic, e.g. in remote areas or places where load is seasonal ($1.1 million per annum).

[1404] Integral Energy noted that the completed 2007–08 regulatory statement will be available prior to the AER making its draft decision.
[1405] Integral Energy, *Regulatory proposal*, p. 136.
[1406] Integral Energy, *Regulatory proposal*, p. 138.

Proposed step changes

Integral Energy indicated that its 2009−10 opex forecast includes a step increase in sub–transmission and zone sub-station maintenance expenditure to clear a backlog. No other step changes were explicitly identified in the Integral Energy proposal.

Escalators

In respect of opex forecasts for the next regulatory control period, Integral Energy has escalated labour expenditures in accordance with the real escalation factors in CEG's report compiled for all three NSW DNSPs. Integral Energy has not applied real cost escalators to non-labour costs.

Integral Energy has also increased direct opex in proportion to recent actual increases in the asset population. The annual rate of increase has been determined at the asset category level using known costs in each category. This escalation has been applied only to direct opex and not to corporate support costs.

Capex/opex trade off

Integral Energy stated that the interaction between capex and opex is implicit in its normal approach to asset management, including in its design and maintenance standards, evaluation of tenders, decisions on maintenance versus replacement and consideration of demand management alternatives.[1407]

In addition, Integral Energy assessed the maintenance savings that will be achieved because of its forecast capital replacement program. The resulting adjustment assumes that the replacement of aged assets will lead to a reduction of approximately 30 per cent in maintenance expenditure. Integral Energy has calculated a resulting saving of $11 million over the next regulatory control period and has deducted this from the projected opex.

Productivity savings

Integral Energy assumed the following productivity savings in its projections:[1408]

- a 2 per cent compounding reduction in labour cost per annum in all business units, including corporate support
- that increases in cost above inflation for the non-labour components of opex will be offset by productivity improvements
- an expectation that savings will arise from the continued rollout of its condition-based maintenance programs.

Integral Energy indicated that these measures are projected to deliver cost reductions of $65 million over the next regulatory control period.

[1407] Integral Energy, *Regulatory proposal*, p. 144.
[1408] Integral Energy, *Regulatory proposal*, p. 139; and response to AER information request, 5 August 2008.

Q.2 Submissions

The EMRF stated that Integral Energy has proposed a forecast opex allowance in excess of historical opex spending and expected growth in demand.[1409]

Q.3 Consultant review

Wilson Cook applied a top-down and bottom-up approach to the assessment of Integral Energy's controllable opex forecasts.

The top-down analysis suggests that Integral Energy's base year level of expenditure cannot be considered inefficient but there may be potential for cost reductions in the business. This has been recognised by Integral Energy, which has included productivity improvements of 2 per cent per annum, compounding over the next regulatory control period.[1410]

Wilson Cook stated that Integral Energy's size-adjusted opex then remains more-or-less constant over the next regulatory control period, despite the real labour cost escalation included in the forecasts. With the effects of real labour cost escalation removed, opex per size drops by 7 per cent over the next regulatory control period, indicating that Integral Energy's relative cost efficiency is forecast to improve significantly against the other NSW and ACT DNSPs over that period.[1411]

From the bottom-up analysis Wilson Cook concluded that two adjustments could be applied to the proposed expenditure, which amount to $25 million. The proposed reductions relate to:[1412]

- defect management costs ($9 million)
- other costs ($16 million).

However, while Wilson Cook identified the above opex adjustments, Wilson Cook considered that the total level of controllable opex proposed by Integral Energy should be accepted without adjustment on the grounds that the identified adjustments are minor, the business has included aggressive productivity improvement assumptions of 2 per cent per annum in its forecasts and the proposed reductions in maintenance expenditure from replacement capex may have been over-estimated. Wilson Cook therefore recommended that Integral Energy's opex forecasts should be accepted without adjustment.[1413]

1409 EMRF, pp. 27–28.
1410 Wilson Cook, volume 3, pp. 36–42.
1411 Wilson Cook, volume 3, p. 42.
1412 Wilson Cook, volume 3, p. 43.
1413 Wilson Cook, volume 3, p. 43.

Q.4 Issues and AER considerations

Q.4.1 Integral Energy forecasting methodology

Integral Energy proposal

Integral Energy used a combination of escalation from a base year and zero based methods to forecast opex in the next regulatory control period. Integral Energy indicated that its opex forecast was underpinned by its network and demand management strategies and the associated corporate and network planning processes.

The forecast costs of self insurance and debt/equity raising costs were then added to give total opex.

Consultant review

Wilson Cook accepted the forecasting methodology applied by Integral Energy.[1414]

Wilson Cook reviewed Integral Energy's asset management plans and found the strategies and processes to be typical of those that a prudent distribution operator would adopt. Wilson Cook also noted that Integral Energy follows a risk-and-condition-based approach to asset management in some asset categories and is extending it to others in the next regulatory control period.[1415]

Wilson Cook examined the components of Integral Energy's forecasting methodology and concluded that the cost escalators were appropriately applied. However, Wilson Cook suggested that the proposed maintenance savings resulting from the forecast capital replacement program were unlikely to be as significant as suggested by Integral Energy's modelling. Further, Wilson Cook considered that the productivity savings incorporated in the Integral Energy modelling were aggressive.[1416]

AER considerations

The AER considers that Integral Energy's forecasting methodology is sound. While the methodology addresses typical issues such as cost and workload escalation, the AER notes that the methodology explicitly addresses the interaction between opex and capex and makes specific provision for targeted productivity improvements.

Based on the AER's assessment and Wilson Cook's advice, the AER considers that Integral Energy has provided a robust methodology for forecasting its opex requirement for the next regulatory control period.

Q.4.2 Efficient base year

Integral Energy proposal

Integral Energy's forecast opex was developed using estimated values for 2007–08 as the efficient base year.[1417] Integral Energy stated that the 2007–08 year provided the

[1414] Wilson Cook, volume 3, p. 12.
[1415] Wilson Cook, volume 3, p. 38.
[1416] Wilson Cook, volume 3, p. 35.
[1417] Integral Energy noted that the completed 2007–08 regulatory statement will be available prior to the AER making its draft decision.

best and most current representation of the costs required to deliver the service standards and obligations during the next regulatory control period.[1418]

Consultant review

Wilson Cook considered the efficiency of the proposed base year opex, using a top-down approach and benchmarking. Wilson Cook indicated that although Integral Energy chose 2007−08 as its base year, Wilson Cook used 2006−07 for benchmarking purposes as this was the latest year of actual data available and is the base year used by the other ACT and NSW DNSPs. Wilson Cook then separately considered the escalation of Integral Energy's expenditure from 2006−07 to 2007–08. [1419]

Wilson Cook used four measures of opex to benchmark the NSW DNSPs: opex $/size; opex $/customer; opex $/MW and opex $/km. Wilson Cook compared Integral Energy's 2006−07 opex against other Australian electricity businesses[1420] in terms of opex $/size and against the predominantly urban electricity businesses in terms of opex $/customer, opex $/MW and opex $/km.[1421]

Wilson Cook considered that the comparisons suggest that Integral Energy's 2006−07 opex is at or a little above the industry norm, established by a number of comparisons. Wilson Cook concluded that Integral Energy's costs were not sufficiently high to suggest its costs were higher than expected and thus implicitly inefficient expenditure levels.[1422]

While Integral Energy's proposed 2007−08 base year opex is 2.5 per cent above the 2006−07 level, Wilson Cook concluded that the difference can be accounted for by real cost escalation in the inputs and asset population growth. On this basis, Wilson Cook indicated that the conclusions drawn from its analysis of 2006–07 costs were equally applicable to the 2007–08 base year adopted by Integral Energy. [1423]

Wilson Cook also noted that, after adjustment, Integral Energy's 2006–07 expenditure is close to its corresponding IPART regulatory allowance (1 per cent over) and that its forecast for 2007–08 is 5 per cent above its regulatory allowance. [1424]

In addition, Wilson Cook analysed the movements in opex that have taken place or are forecast by the ACT and NSW DNSPs to occur in the period from 2006−07 to 2013−14 (based on opex by size). Based on this measure, Wilson Cook indicated that Integral Energy's expenditure in 2009−10 is 10 per cent above that in 2006−07 and remains almost constant thereafter. Wilson Cook noted that the rate of increase in

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[1418] Integral Energy, *Regulatory proposal*, p. 136.
[1419] Wilson Cook, volume 3, p. 36.
[1420] Wilson Cook, volume 1, pp. 18–25.
[1421] Adjustments were made to the 2006–07 reported figures of all businesses to remove abnormal and one-off items. The adjustments made for Integral Energy related to the superannuation fund and provisions.
[1422] Wilson Cook, volume 3, p. 36.
[1423] Wilson Cook, volume 3, p. 36.
[1424] Wilson Cook, volume 3, p. 37.

Integral Energy's opex from 2006−07 to 2009−10 is less than that forecast by the other DNSPs.[1425]

After allowing for real labour cost escalation, Integral Energy's 2009–10 opex per size is 2 per cent above the 2006–07 level and the average over the next regulatory control period is 3 per cent lower than the 2006–07 level. Further, by 2013–14, Integral Energy's opex per size is forecast to be 7 per cent below its 2006–07 level. Wilson Cook stated that this analysis shows that, over the next regulatory control period, Integral Energy's relative cost efficiency is forecast to improve significantly against the other businesses in the comparison.[1426]

Based on the analysis, Wilson Cook indicated that it supported the use of Integral Energy's 2007−08 opex as the basis for projection of its opex requirements in the next regulatory control period.[1427]

AER considerations

The AER accepts the benchmarking assessment and associated conclusions provided by Wilson Cook. The AER also notes that Integral Energy's estimated opex for 2007−08 is close to the corresponding forecast opex allowance provided in the previous determination. Integral Energy's estimated opex is $12 million (5 per cent) higher than forecast in the determination. While the estimated opex is not the same as that provided in the current IPART determination, the AER considers that it is sufficiently close to accept Integral Energy's proposal, in that it indicates an efficient level of opex.

On the basis of this information the AER is satisfied that Integral Energy's base year is representative of efficient expenditure from which to project its forecast opex requirements.

Q.4.3 Operating and maintenance expenditure

Integral Energy forecast operating and maintenance expenditure of $881 million over the next regulatory control period, consisting of:[1428]

- inspection expenditure ($83 million)
- maintenance expenditure ($530 million)
- other operating expenditure ($268 million).

Each of these expenditure categories is discussed below.

[1425] Wilson Cook, volume 3, p. 37.
[1426] Wilson Cook, volume 3, p. 37.
[1427] Wilson Cook, volume 3, p. 38.
[1428] Integral Energy, *Regulatory proposal*, p. 141.

Q.4.3.1 Inspections

Integral Energy proposal

Table Q.2 shows the forecast expenditure on inspections for the next regulatory control period.

Table Q.2: Integral Energy's forecast inspections ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Sub-transmission and zone substations	0.7	0.7	0.7	0.7	0.8	3.6
Distribution substations	0.5	0.5	0.5	0.5	0.6	2.6
Overhead and ground line	8.8	8.9	8.8	8.8	8.9	44.3
Installation inspections	6.1	6.1	6.4	6.7	7.2	32.5
Total	16.1	16.2	16.4	16.9	17.4	83.0

Source: Integral Energy, *Regulatory proposal*, p. 140.
Note: Totals may not add up due to rounding.

The proposed expenditure in the next regulatory control period is $83 million compared with $70 million in the current regulatory control period, which is an increase of 18 per cent. Average annual expenditure over the next regulatory control period is $17 million, or 24 per cent above the base year level.

The base year expenditure has been escalated by asset population growth and real labour growth and allowance has been made for productivity improvement. In addition, extra expenditure has been proposed from 2009–10 onwards for two additional programs to inspect the earths in older houses. The total cost of these two programs is $1.7 million per annum for the duration of the next regulatory control period.

Consultant review

Wilson Cook reviewed Integral Energy's inspection cycle period and found its use to be consistent with industry practice. It considered the proposed expenditure for inspections is consistent with historical levels after allowing for increases in the asset population and that the additional programs, cost escalation and productivity improvement allowances were reasonable.[1429]

Wilson Cook also reviewed the two projects relating to the inspection of earths in older houses and concluded that these programs are prudent. [1430]

AER considerations

The AER notes the forecast inspection costs were derived using labour cost escalators and CPI escalators for non-labour components. The labour cost escalators are subject

[1429] Wilson Cook, volume 3, p. 39.
[1430] Wilson Cook, volume 3, p. 39.

to adjustment, as noted in chapter 8 and appendix N of this draft decision, and hence the forecasts for inspection opex will vary from that proposed by Integral Energy.

Based on Wilson Cook's advice, the AER considers that Integral Energy's forecast opex for inspections (with adjustments to the cost escalators) reflects the efficient costs that a prudent operator in the circumstances of Integral Energy would require to achieve the opex objectives.

Q.4.3.2 Maintenance

Integral Energy proposal

Table Q.3 shows the forecast maintenance expenditure for the next regulatory control period.

Table Q.3: Integral Energy's forecast maintenance expenditure ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Subtransmission and zone substations	10.0	10.5	10.1	10.4	10.9	51.9
Subtransmission mains	1.0	1.0	1.0	1.1	1.1	5.3
Distribution substations	1.8	2.0	1.8	1.9	2.1	9.7
Distribution mains	3.0	2.5	3.0	3.0	3.2	14.7
Network buildings	7.0	6.5	7.1	7.5	7.9	36.0
Defect management	20.1	20.0	21.6	21.8	22.1	105.6
Fault and emergency response	21.5	21.5	22.2	21.9	21.7	108.9
Vegetation management	37.9	38.9	39.3	40.4	41.6	198.1
Total	102.4	102.9	106.2	108.1	110.5	530.1

Source: Integral Energy, *Regulatory proposal*, p. 140.
Note: Totals may not add up due to rounding.

Expenditure in the next regulatory control period is forecast to be $530 million compared with $416 million in the current regulatory control period, which is an increase of 28 per cent. Average annual expenditure over the next regulatory control period is $106 million, or 14 per cent above the base year level.

Base year expenditure has been escalated by asset population growth and real labour cost growth and allowance has been made for productivity improvement. In addition, Integral Energy indicated that extra expenditure has been allowed under this category for:

- an increased effort to address the backlog in sub–transmission and zone substation maintenance

- a compounding 3.1 per cent increase in defect management work to reduce a maintenance backlog

- an increase in vegetation management to meet the NSW industry safety steering committee requirements.

Offsetting these additions, Integral Energy allowed for reductions of $6 million over the later years of the next regulatory control period arising from improved maintenance strategy and reductions of $11 million from savings arising from the proposed capital replacement program.

Consultant review

Wilson Cook concluded that Integral Energy's approach to maintenance activities is reasonable but with some scope for improvement in planning and implementation. Wilson Cook indicated that the improvement strategies proposed by Integral Energy should address these improvement opportunities.[1431]

Wilson Cook also noted that PB had carried out a high-level review of Integral Energy's distribution and sub–transmission maintenance practices, policies and asset maintenance plans and had formed the view that they are reasonable.[1432]

Wilson Cook proposed a minor reduction to Integral Energy's proposed defect management expenditure, noting that it was to clear a backlog, but stated that there have been substantial increases in expenditure on defect management since 2006−07 and that a step change is also proposed in sub–transmission and zone substation maintenance expenditure to clear a backlog. Wilson Cook considered that these other increases should be sufficient to clear the backlog and that the further compounding increase should not be required. Wilson Cook proposed a reduction of $9 million to remove the compounding growth rate. Apart from this adjustment, Wilson Cook concluded that Integral Energy's proposed maintenance expenditure is reasonable.[1433]

While Wilson Cook identified the above opex reduction, it considered that Integral Energy's proposed maintenance expenditure should be accepted without adjustment on the grounds that the identified adjustment is minor, the business has adopted aggressive productivity improvement assumptions and its reductions in maintenance expenditure from replacement capex may have been over-estimated. In particular, Wilson Cook indicated that, in spite of its forecast asset replacement program, the average age of Integral Energy's network was still expected to increase and thus forecast savings in maintenance expenditure were unlikely to be realised. Wilson Cook therefore recommended that Integral Energy's maintenance expenditure forecasts should be accepted without adjustment.[1434]

AER considerations

The AER notes that Wilson Cook's bottom-up review identified an issue with respect to Integral Energy's growth escalation assumption used to derive its defect

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[1431] Wilson Cook, volume 3, p. 39.
[1432] Wilson Cook, volume 3, p. 39.
[1433] Wilson Cook, volume 3, p. 40.
[1434] Wilson Cook, volume 3, p. 43.

management expenditure forecast. It also notes that Wilson Cook has assessed the other expenditure in the maintenance forecasts to be reasonable.

The AER further notes that Integral Energy applied a compounding increase to defect management expenditure to address a backlog of defects. Based on Wilson Cook's assessment, the AER agrees that increases in expenditure on defect management since 2006–07 and the step change in sub–transmission and zone substation maintenance expenditure should be sufficient to clear the backlog and that the further compounding increase should not be required. The AER therefore considers that the adjustment to defect management expenditure as identified by Wilson Cook of $9 million to remove the effects of this compounding is appropriate.

The AER notes, however, that Wilson Cook has also adopted a top-down approach to the assessment of Integral Energy's forecast controllable opex. In doing so, Wilson Cook concluded that, in light of the ambitious reductions to forecast controllable opex proposed by Integral Energy, Wilson Cook's identified adjustment to Integral Energy's forecast defect management expenditure was not warranted.

As previously discussed, the AER considers that Wilson Cook's top-down and bottom-up assessment of the DNSPs' opex forecasts represents an appropriate approach to the assessing efficient costs. The AER considers that applying the Wilson Cook identified adjustment to Integral Energy's forecast defect management expenditure without consideration of the efficiency of Integral Energy's aggregate controllable opex forecast does not reflect a balanced assessment of efficient costs.

Consistent with its approach to the assessment of EnergyAustralia's opex forecasts, the AER has considered both the top-down and bottom-up assessments of Integral Energy's opex forecasts. The AER accepts Wilson Cook's recommendation to forgo the identified adjustment for defect management expenditure in light of the ambitious reductions in other areas of forecast opex proposed by Integral Energy.

On balance, the AER considers that Integral Energy's forecast maintenance expenditure (with adjustments to the cost escalators) reflects the efficient costs that a prudent operator in the circumstances of Integral Energy would require to achieve the opex objectives.

Q.4.3.3 Other operating expenditure

Integral Energy proposal

Table Q.4 shows Integral Energy's forecast expenditure on other operating activities for the next regulatory control period.

Table Q.4: Integral Energy’s forecast other operating expenditure ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
System switching	16.9	17.2	16.9	17.5	18.1	86.6
Metering	19.3	14.4	21.0	22.1	23.4	100.2
Third party recoveries	2.2	2.2	2.2	2.2	2.2	11.0
Quality of supply investigations	1.0	0.6	1.0	1.1	1.2	4.9
Other costs	11.4	15.7	12.0	12.7	13.4	65.2
Total	50.7	50.1	53.3	55.5	58.3	267.9

Source: Integral Energy, *Regulatory proposal*, pp. 140–141.
Note: Totals may not add up due to rounding.

Expenditure in the next regulatory control period is $268 million compared with $195 million in the current regulatory control period, which is an increase of 37 per cent. Average annual expenditure over the next regulatory control period is $54 million, or 29 per cent above the base year level.

Integral Energy escalated base year other opex by asset population growth and real labour escalation and included an allowance for productivity improvement. In addition, Integral Energy included further expenditure from 2009–10 for various small activities and for additional resources in the metering sub-category for ‘customer churn’.

Consultant review

Wilson Cook considered that the proposed additional expenditure from 2009–10 did not adequately explain the 46 per cent increase in expenditure under the ‘other costs’ sub-category from the base year to 2009−10. Wilson Cook therefore calculated an appropriate amount by applying the average escalation over the next regulatory control period (3.5 per cent) to the base year to derive a more appropriate estimate. Wilson Cook also made an adjustment to correct an apparent expenditure shift between the ‘metering’ and ‘other’ sub-categories within the other opex category in 2010−11. In total, Wilson Cook proposed a $16 million reduction to Integral Energy’s other opex forecast. Apart from this adjustment, Wilson Cook considered the other expenditure to be reasonable.[1435]

Similar to its finding in relation to defect management costs, while Wilson Cook’s bottom-up identified the above opex reductions, its top-down assessment suggested these reductions were offset by savings in other areas of opex. In particular, Wilson Cook considered that Integral Energy has adopted aggressive productivity improvement assumptions and its reductions in maintenance expenditure from replacement capex may have been over-estimated. Wilson Cook therefore

[1435] Wilson Cook, volume 3, p. 41.

recommended that Integral Energy's other opex forecasts should be accepted without adjustment.[1436]

AER considerations

The AER notes that Wilson Cook's bottom-up review identified issues with respect to Integral Energy's growth escalation assumptions used to forecast some sub-categories that make up its other opex forecasts. It also notes that Wilson Cook has assessed the forecasts for the remaining sub-categories in the other opex category to be reasonable.

The AER considers that the increase in the other costs sub-category from the base year to 2009−10 is not supported by the information provided by Integral Energy. The AER notes Wilson Cook has identified a reduction of $16 million as a result of applying the average cost escalation of the next regulatory control period to Integral Energy's base year opex to derive a new level of expenditure. However, as discussed in relation to defect management expenditure, the AER considers that it is appropriate to review opex from both a bottom-up and top-down perspective. In doing so, the AER accepts Wilson Cook's recommendation to forgo the proposed reduction in other operating expenditure in light of the ambitious reductions in other areas of forecast opex proposed by Integral Energy. The AER considers that Integral Energy's forecast other opex (with adjustments to the labour cost escalators) reflects the efficient costs that a prudent operator in the circumstances of Integral Energy would require to achieve the opex objectives.

Q.4.4 Corporate support expenditure

Corporate support expenditure includes activities such as the CEO, company secretary, executive management, finance, human resources, IT and regulatory areas. Under Integral Energy's business model, these costs are shared between the network and retail businesses.

Integral Energy proposal

Table Q.5 shows Integral Energy's forecast corporate support expenditure for the next regulatory control period.

[1436] Wilson Cook, volume 3, p. 43.

Table Q.5: Integral Energy's forecast corporate support expenditure ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Board	3.4	1.2	1.5	1.9	1.3	9.4
Company secretary	4.2	4.2	4.2	4.2	4.2	20.9
Finance	31.3	30.8	31.0	31.3	31.4	155.7
Human resources	28.7	28.6	27.2	27.5	27.7	139.6
Regulatory and corporate affairs	36.8	38.0	36.2	37.3	38.4	186.8
Retail and customer services	7.7	7.6	7.5	7.5	7.5	37.8
Total	112.1	110.5	107.7	109.6	110.3	550.2

Source: Integral Energy, *Regulatory proposal*, p. 143.
Note: Totals may not add up due to rounding.

Expenditure in the next regulatory control period is $550 million compared with $451 million in the current regulatory control period, which is an increase of 22 per cent. The average annual expenditure over the next regulatory control period is $110 million, or 8 per cent above the base year level. Base year expenditure has not been escalated by asset population growth but labour escalation and productivity improvements have been applied. In addition, extra expenditure has been allowed for:

- increased accounting resources for financial governance of increased programs
- additional maintenance costs, leases, rates and taxes on the property portfolio
- costs associated with additional apprenticeships and training programs for cadets and graduates
- additional IT costs due to higher activity and staff levels including contract renewal and offsetting cost reductions
- environmental improvement costs.

Integral Energy stated that its corporate support costs have been allocated to the network business in accordance with the AER's approved cost allocation method.

Consultant review

Wilson Cook noted that the increases in corporate support costs from the base year are relatively modest, with the major change being the increase in training costs. This increase is common to all DNSPs and to the industry in Australasia at large.[1437]

[1437] Wilson Cook, volume 3, p. 42.

Wilson Cook also noted that Integral Energy used the electricity, gas and water (EGW) sector's labour escalation rate for corporate support expenditure, rather than a general labour rate. Further discussion with Integral Energy indicated that over 90 per cent of Integral Energy's staff are covered by a single enterprise bargaining agreement and the same wage escalation rate is applied to all staff. On this basis, Wilson Cook accepted the labour escalator used by Integral Energy. Overall, Wilson Cook recommended that Integral Energy's corporate support expenditure forecasts should be accepted without adjustment.[1438]

AER considerations

The AER notes that Wilson Cook's review of Integral Energy's corporate support expenditure to be reasonable. The AER has reviewed the type of labour escalators applied by Integral Energy and is satisfied with the analysis put forward by Integral Energy to support its proposal. However, the labour cost escalators are subject to adjustment based on more updated information, as noted in appendix N of this draft decision, and hence the forecasts for corporate support opex will vary from that proposed by Integral Energy.

Taking account of Wilson Cook's advice, the AER considers that Integral Energy's forecast opex for corporate support (with adjustments to the cost escalators) reflects the efficient costs that a prudent operator in the circumstances of Integral Energy would require to achieve the opex objectives.

Q.5 AER conclusion

The AER has decided not to adjust Integral Energy's underlying forecast controllable opex for the next regulatory control period (other than for revised cost escalators). Integral Energy's forecast controllable opex is set out in table Q.6.

The AER notes Integral Energy's forecast controllable opex was derived using labour cost escalators for the labour component and CPI escalators for non-labour components. The labour cost escalators are subject to adjustment, as noted in chapter 8 and appendix N of this draft decision, and hence the forecast controllable opex will be subject to adjustment.

Table Q.6: AER's adjustments to Integral Energy's forecast controllable opex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Integral Energy's proposed controllable opex	281.3	279.6	283.6	290.2	296.6	1431.3
AER's adjustments	–	–	–	–	–	–
AER's total controllable opex	281.3	279.6	283.6	290.2	296.6	1431.3

Note: The AER's controllable opex has not yet been adjusted for labour cost escalators.

[1438] Wilson Cook, volume 3, p. 42.

Appendix R: Self insurance

This appendix sets out the AER's assessment of the NSW DNSPs' proposed self insurance allowances in their opex forecasts for the next regulatory control period.

AER considerations

Since self insurance is not specifically addressed in the NER, the NSW DNSPs' self insurance claims have been assessed by the AER against the opex objectives and criteria in clauses 6.5.6 of the transitional chapter 6 rules. Specifically, the AER has assessed the NSW DNSPs' self insurance claims to determine whether the proposed allowances reasonably reflect the efficient costs that prudent operators in the circumstances of the NSW DNSPs would require to achieve the opex objectives.

The self insurance premiums proposed by the DNSPs' consultant (SAHA) have been derived by estimating the annual probability of each proposed self insurance event occurring and the costs associated with each of those events occurring.[1439]

The AER has assessed the efficiency and prudence of the proposed self insurance claims by considering whether the probability of an event occurring and the costs associated with the event (and therefore the associated insurance premium) have been reasonably determined.

Having reviewed the analysis by SAHA the AER is satisfied that the NSW DNSPs' proposed allowances for self insurance for the following risks reasonably reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives:

- fraud risk
- insurers' credit risk
- counterparty credit risk
- workers compensation risk.

However, the AER does not consider that all of the proposed self insurance premiums reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives and is concerned that in several areas they do not represent a realistic expectation of the costs of self insurance required in the next regulatory control period. These areas of concern are discussed further below.

[1439] SAHA, *Country Energy Self Insurance Risk Quantification,* final report, 19 May 2008; SAHA, *Integral Energy Self Insurance Risk Quantification*, final report, 19 May 2008; SAHA, *EnergyAustralia Self Insurance Risk Quantification*, final report, 19 May 2008.

Bomb threat/hoax, terrorism[1440]

Country Energy and EnergyAustralia have proposed a self insurance premium for the cost impact of a bomb threat, hoax or terrorism event.[1441] The self insurance premiums for Country Energy and EnergyAustralia are:

- Country Energy—$13 000 per annum which consists of $2000 per annum for the impact of a bomb threat, hoax or extortion and $11 000 per annum for acts of terrorism

- EnergyAustralia—$74 000 per annum which consists of $2000 per annum for the impact of a bomb threat, hoax or extortion and $72 000 per annum for acts of terrorism.

The AER is satisfied with the assumptions used by SAHA to calculate the self insurance premiums for the impact of a non terror related bomb threat, hoax or extortion on the DNSPs, and therefore accepts these premiums for Country Energy and EnergyAustralia.

In respect of an extortion or bomb threat that pertains to a terrorist related event, the NSW DNSPs are eligible under the *Terrorism Act 2003* to claim any loss or damage done to its property and consequential third party liability as a result of a stated terrorist act. However, the *Terrorism Act 2003* only covers eligible insured assets, with any consequent financial costs resulting from terrorist acts on self insured assets being borne by the NSW DNSPs.

In calculating the self insurance premium for the risk of a terrorism event, SAHA noted that it is difficult to determine the probability of how often the DNSPs' assets may be subject to acts of terrorism and what the cost of a terrorism event would be. Nonetheless, SAHA made assumptions about the probability of a terrorism act occurring to calculate the risk premium for self insurance purposes.

The AER notes that under the NER a terrorism event is a defined pass through event.

Given the difficulty associated with calculating a risk premium for a terrorism event and that a terrorism event is listed as a defined pass through event under the NER, the AER considers that the claim for self insurance should be rejected. If a terrorism event occurred the DNSPs would be able to submit a pass through application to cover the costs associated with the event. The AER would assess any such application, in accordance with the NER and any relevant guidelines, at the time it was made.

Summary

The AER will accept the premiums of $2 000 per annum ($13 000 − $11 000) for Country Energy and $2 000 per annum for EnergyAustralia ($74 000 − $72 000) for the bomb threat/hoax risk. The AER does not accept the self insurance premium for

[1440] SAHA, *Country Energy Self Insurance Risk Quantification,* pp. 51–58; SAHA, *Integral Energy Self Insurance Risk Quantification*, pp. 47–54; SAHA, *EnergyAustralia Self Insurance Risk Quantification*, pp. 52–59.

[1441] Integral Energy did not propose a self insurance premium for bomb threats, hoax or terrorism.

terrorism event. The AER considers that the revised premiums reflect the efficient costs that a prudent operator in the circumstances of Country Energy and EnergyAustralia would require to achieve the opex objectives.

Earthquake[1442]

Country Energy and Integral Energy have proposed self insurance premiums for the cost impact of an earthquake of magnitude 5 and 6 impacting on their networks. The self insurance premiums are:

- Country Energy—$79 000 per annum which consists of $62 000 for the impact of a magnitude 5 earthquake and $17 000 for the impact of a magnitude 6 earthquake

- Integral Energy—$255 000 per annum which consists of $198 000 for the impact of a magnitude 5 earthquake and $57 000 for the impact of a magnitude 6 earthquake.

SAHA examined the number of earthquakes impacting each Australian state over the last 166 years to determine the future probability of an event for each DNSP. The data allowed SAHA to examine how many of these earthquakes occurred in each DNSP's network area and provide an estimate of potential costs. SAHA calculated the potential cost associated with a magnitude 5 earthquake based on the average length of line affected by an earthquake.

The AER is satisfied that the assumptions used by SAHA to calculate the self insurance premium for the impact of a magnitude 5 earthquake on the DNSPs are reasonable and therefore accepts the self insurance premiums proposed by Country Energy and Integral Energy.

In the case of magnitude 6 earthquakes, SAHA indicated that no such earthquakes were recorded in NSW over the 166 year period. However, SAHA assumed that there was a potential for at least one magnitude 6 earthquake to occur in NSW over this period and therefore adopted a probability of 1 in 166 years.

The AER notes that earthquake forecasting can be regarded, at best, as imprecise. Where there are no historical observations, as is the case for magnitude 6 earthquakes in NSW, earthquake prediction could be considered virtually impossible. The AER considers that SAHA has provided no reasonable rational basis for the adoption of a 1 in 166 year probability of a magnitude 6 earthquake in NSW.

The AER rejects the self insurance claim for a magnitude 6 earthquake on the basis that the estimate of the probability of occurrence is not sufficiently robust to be used to determine the self insurance allowance. Based on the information provided, the AER considers that the proposed self insurance premiums for earthquakes of a magnitude 6 do not reflect the efficient costs that a prudent operator in the circumstances of Country Energy and Integral Energy would require to achieve the opex objectives.

1442 SAHA, *Country Energy Self Insurance Risk Quantification,* pp. 59–70; SAHA, *Integral Energy Self Insurance Risk Quantification*, pp. 55–66.

Summary

The AER accepts the proposed self insurance premiums for earthquakes of magnitude 5:

- Country Energy—$62 000 per annum
- Integral Energy—$198 000 per annum.

Bushfire[1443]

The NSW DNSPs have proposed the following self insurance premiums for bushfire risks:

- Country Energy—$540 000 per annum
- EnergyAustralia—$504 000 per annum.
- Integral Energy—$1.18 million per annum.

SAHA's assessment of bushfire risk was separated into two types of bushfires—those ignited by the DNSP's own assets, and those ignited by a third party. Each of these scenarios is examined below.

Bushfires ignited by a DNSP's own assets[1444]

This self insurance premium is based on the probability of the DNSP's own assets starting a major bushfire—that is, a bushfire causing more than $10 million damage.

The SAHA approach to determining the probability of a major bushfire ignited by a DNSP's own assets is summarised as follows:

- Determine the number of minor bushfires in NSW caused by electricity assets over the past 11 years (8 per annum over the past 11 years).[1445] SAHA indicated that this translated to approximately 88 (i.e. 8 × 11) minor bushfires caused by electricity assets over the past 11 years since the inception of the DNSPs.
- Over this (11 year) period, only one major bushfire had occurred—the Appin fire started by Integral Energy's network. SAHA therefore calculated the probability of a minor bushfire ignited by a DNSP's assets becoming a major bushfire as 1 in 88.
- Apply the average annual number of minor bushfires for each NSW DNSP caused by electricity assets to the expected probability of a minor bushfire becoming a

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1443 SAHA, *Country Energy Self Insurance Risk Quantification,* pp. 81–91; SAHA, *Integral Energy Self Insurance Risk Quantification*, pp. 77–87; SAHA, *EnergyAustralia Self Insurance Risk Quantification*, pp. 80–91.

1444 SAHA, *Country Energy Self Insurance Risk Quantification,* pp. 84–89; SAHA, *Integral Energy Self Insurance Risk Quantification*, pp. 80–85; SAHA, *EnergyAustralia Self Insurance Risk Quantification*, pp. 84–88.

1445 Based on information provided to SAHA by the NSW DNSPs (incorporates very minor and minor bushfires ignited by electricity assets).

major bushfire (i.e. 1 in 88) to determine the individual probability of occurrence for each of the DNSPs.

The AER considers that the basis for determining the probability of these events is not robust. In particular:

- there is no rationale for the application of an 11 year historical period. The AER notes that there is nothing inherently important about the inception date of the DNSPs. Notwithstanding this point, the AER also notes that Country Energy was formed in 2001 (that is, 7 years ago in the context of the SAHA analysis)[1446]

- the fact that 1 bushfire has occurred since the inception of Integral Energy (11 years ago) does not provide a basis for assuming that another major bushfire will occur in 11 years. There are other factors that are likely to impact on the probability of such an event rather than 1 historical observation over an arbitrary timeframe

- it is not clear that the DNSPs' experience with minor bushfires can be used to predict the possibility of a major bushfire.

In calculating the costs associated with a major bushfire ignited by the DNSP's own assets, SAHA relied on information from the Centre for International Economics (CIE).[1447] In particular, SAHA relied upon a functional relationship between damage costs and area burnt by bushfires proposed by CIE.[1448] It should be noted that the CIE report was not undertaken in connection with the NSW DNSPs' regulatory proposals.

The AER considers that the functional relationship between damage costs and area burnt proposed by CIE cannot be relied upon. In particular, based on an examination of the historical data underpinning the CIE modelling, the AER is unable to unambiguously match the values provided in the CIE report with those in the base data.[1449] In addition, for those values that can be identified, it appears that the damage costs used by CIE to forecast the relationship have not been converted to constant dollars. As such, the observations are not comparable over time.

Notwithstanding the data issues set out above, the explanatory power of the proposed CIE functional relationship is poor. The coefficient of determination is reported as 0.39, implying that only 39 per cent of the variation in bushfire damage cost can be explained by the amount of hectares burnt.[1450]

As a result, based on the information provided, the AER rejects the self insurance premiums for bushfires ignited by a DNSPs' assets proposed by the NSW DNSPs on

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[1446] Country Energy, *Regulatory proposal*, p. 13.
[1447] CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, November 2000.
[1448] CIE, *CSIRO pricing review*, November 2000, pp. 112–113.
[1449] this assessment is based on an examination of the data source in its current format, given the historical nature of the data, the AER would not expect any deviation between this data set and that used by CIE over the observed timeframe. See: http://www.ema.gov.au/ema/emadisasters.nsf/webEventsByCategory?OpenView&Start=1&Count=30&Expand=1#1.
[1450] CIE, *CSIRO pricing review*, November 2000, p. 113.

the basis that the estimate of the probability of occurrence and costs associated with the event are not sufficiently robust to be used to determine the self insurance premiums.

***Bushfire ignited by third party*[1451]**

The self insurance premium for bushfires ignited by a third party consists of a premium for minor bushfires and a premium for major bushfires.

SAHA noted that there is no history of a (minor or major) bushfire ignited by a third party impacting on the DNSPs. However, SAHA suggested that the sheer number of fires per annum ignited by a third party—around 300 per year—indicated that there was a considerable chance that one such minor bushfire could cause damage to the DNSPs' asset base.[1452] Accordingly, SAHA suggested that it was reasonable to assume a DNSP in NSW would be impacted by a minor bushfire incident caused by a third party once every 15 years.[1453]

The AER notes that the NSW bushfire data referred to by SAHA reflects bushfire incidents in only one year (2002−03) and represented one of the worst bushfire seasons in NSW history.[1454] Notwithstanding this issue, the AER considers that SAHA has not established a robust relationship between the incidence of bushfires in NSW and the adoption of the associated probabilities.

In the case of a major bushfire ignited by a third party, SAHA used the CIE report to derive the probability of a major bushfire in NSW. SAHA combined this information with the previously derived probability of a third party causing a bushfire incident in NSW to calculate the probability of a major bushfire being ignited by a third party in NSW.

The AER notes that the proportion of major bushfires accounted for in NSW (from the CIE report) appears to relate to minor rather than major bushfires as proposed by SAHA.[1455] Further, as mentioned above, SAHA has provided no explanation for the assumed probabilities of a minor bushfire incident caused by a third party impacting the DNSPs.

As a result, based on the information provided, the AER considers that the probabilities for both minor and major bushfires ignited by a third party do not provide a reasonable basis to calculate the self insurance premium.

In addition, the AER notes that SAHA's forecast costs associated with minor and major bushfires ignited by third parties were derived on the same basis as those for a major bushfire ignited by the DNSPs' assets—that is, based on the CIE proposed

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1451 SAHA, *Country Energy Self Insurance Risk Quantification,* pp. 89–91; SAHA, *Integral Energy Self Insurance Risk Quantification*, pp. 85–87; SAHA, *EnergyAustralia Self Insurance Risk Quantification*, pp. 89–91.

1452 SAHA obtained this information from a 2002−03 NSW Rural Fire Services report.

1453 SAHA reduced this probability to 1in every 30 years for EnergyAustralia on the basis that EnergyAustralia operates in the metropolitan region which is less prone to bushfire hazard.

1454 NSW Rural Fire Service, *Annual Report 2003*.

1455 CIE, *CSIRO pricing review*, November 2000, p. 108 and table 7.5.

relationship between damage costs and damage area. As noted, the AER has identified a number of issues associated with the functional relationship used by the CIE.

Based on the above assessment, the AER rejects the self insurance premiums in relation to both minor and major bushfires ignited by a third party on the basis that the probability of occurrence and associated costs have not been reasonably determined.

Summary

The AER does not consider that the proposed self insurance premiums for the risk of bushfires reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives. Accordingly, the AER does not accept the proposed self insurance premiums of $540 000 per annum for Country Energy, $504 000 per annum for EnergyAustralia and $1.18 million per annum for Integral Energy.

Risk of non-terrorist impact of planes and helicopters[1456]

The NSW DNSPs have proposed the following self insurance premiums for the risk of a non-terrorist aviation strike impacting on their assets:

- Country Energy—$57 000 per annum
- EnergyAustralia—$11 000 per annum
- Integral Energy—$138 000 per annum.

SAHA calculated the annual probability of an aircraft accident or incident for Integral Energy and Country Energy based on the historical incidence of strikes for each business. The AER is satisfied with the assumptions used by SAHA to calculate the self insurance premium for the impact of an aviation strike and accepts the self insurance premiums of $138 000 per annum and $57 000 per annum for Integral Energy and Country Energy respectively.

In the case of EnergyAustralia, SAHA indicated that data from the Australian Transport Safety Bureau showed an average of 5 wire strike accidents per year, but noted that this included occurrences to assets not owned by EnergyAustralia and also included transmission lines. On the basis that EnergyAustralia had never experienced an incident of wire strike and given the largely urban nature of EnergyAustralia's network, SAHA considered that there was a low but non-zero probability of an accident. As such, SAHA adopted a figure of 1 wire strike incident during the next regulatory period (0.2 accidents per annum) for EnergyAustralia.

Based on the information provided, the AER rejects the self insurance premium of $11 000 proposed by EnergyAustralia on the basis that SAHA has not provided a sufficiently robust estimate for the probability of an aviation strike on EnergyAustralia's network to be used to determine the self insurance premium. The AER does not consider that the proposed self insurance premium reflects the efficient

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[1456] SAHA, *Country Energy Self Insurance Risk Quantification,* pp. 97–104; SAHA, *Integral Energy Self Insurance Risk Quantification*, pp. 93–100; SAHA, *EnergyAustralia Self Insurance Risk Quantification*, pp. 99–104.

costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives

Summary

The AER accepts the self insurance premiums of $138 000 per annum and $57 000 per annum for Integral Energy and Country Energy respectively. The AER does not accept the proposed self insurance premium for EnergyAustralia of $11 000 per annum.

Poles and lines[1457]

Country Energy and EnergyAustralia sought self insurance in relation to damage to their poles and lines as a result of a catastrophic storm.[1458] The proposed self insurance premiums are:

- Country Energy—$279 000 per annum
- EnergyAustralia—$763 000 per annum.

SAHA proposed that the probability of a catastrophic storm impacting Country Energy was 1 in 30 years.[1459] This probability was based on a media statement from the NSW Fire Brigade which indicated that the storms that hit the Lower Hunter area of New South Wales in June 2007 resulted in the region's 'worst natural disaster in 30 years'.[1460]

The AER considers that the media statement relied upon by SAHA does not constitute a robust assessment of the probability of a catastrophic storm impacting Country Energy's network and therefore does not accept the adoption of a 1 in 30 year probability of such an event.

A higher probability was applied to EnergyAustralia based on EnergyAustralia's recent experience with catastrophic storms. SAHA suggested that the probability of a catastrophic storm occurring in the EnergyAustralia network was 1 in 11 years. This conclusion was based on the fact that EnergyAustralia had experienced one catastrophic storm, in the Lower Hunter Valley region, since its inception 11 years ago.

The AER considers that the basis for determining the probability of a catastrophic storm for EnergyAustralia is not robust. In particular:

- there is no rationale for the application of an 11 year historical period. The AER notes that there is nothing inherently important about the inception date of EnergyAustralia

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1457 SAHA, *Country Energy Self Insurance Risk Quantification,* pp. 105–113; SAHA, *EnergyAustralia Self Insurance Risk Quantification*, pp.105–114.

1458 Integral Energy did not seek a self insurance premium for poles and lines damage.

1459 The NSW DNSPs have agreed that a catastrophic storm represents a storm relative in nature to the 2007 Lower Hunter Valley storm.

1460 NSW Fire Brigade, *Firefighters go above and beyond during Newcastle, Central Coast and Hunter Valley storms and floods*, http://www.fire.nsw.gov.au/page.php?id=724, October 2007.

- the fact that 1 catastrophic storm has occurred since the inception of EnergyAustralia (11 years ago) does not provide a basis for assuming that another catastrophic storm will occur in 11 years.

Based on the information provided, the AER rejects the self insurance premiums for both Country Energy and EnergyAustralia on the basis that the estimate of the probability of occurrence is not sufficiently robust to be used to determine the self insurance premiums.

Summary

The AER does not consider that the proposed self insurance premiums reflect the efficient costs that a prudent operator in the circumstances of EnergyAustralia or Country Energy would require to achieve the opex objectives. Accordingly, the AER does not accept the self insurance premiums of $279 000 per annum for Country Energy and $763 000 per annum for EnergyAustralia.

Key assets[1461]

EnergyAustralia and Country Energy have proposed the following self insurance premiums for the failure of key assets:

- Country Energy—$2.76 million per annum
- EnergyAustralia—$2.69 million per annum.

This self insurance claim relates to the failure of power transformers, distribution transformers and circuit breakers, and the associated costs for the DNSPs, including third party claims.

The AER is satisfied with the assumptions used by SAHA to calculate the self insurance premium for costs associated with the failure of power transformers, distribution transformers and circuit breakers, and therefore accepts the self insurance premiums for these components proposed by Country Energy and EnergyAustralia.

As part of its proposed self insurance premium, EnergyAustralia included an amount for claims made by third parties. EnergyAustralia advised that it had not experienced any third party claims in relation to the failure of its key assets. However, SAHA considered it reasonable to assume that such an incidence could occur, and believed that a 1 in 11 year probability of consequential third party damage occurring was reasonable.

The AER notes that SAHA has provided no information in support of this conclusion. As such, the AER has rejected the claim on the basis that the estimate of the probability of occurrence is not sufficiently robust to be used to determine the self insurance premium relating to third party claims. The AER does not consider that the proposed amount included in the self insurance premiums for third party claims reasonably reflects the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives.

[1461] SAHA, *Country Energy Self Insurance Risk Quantification,* pp. 118–139; SAHA, *EnergyAustralia Self Insurance Risk Quantification*, pp. 119–131.

Summary

The AER accepts Country Energy's self insurance premium of $2.76 million per annum for the risk of key asset failure. The AER does not accept the proposed self insurance premium for EnergyAustralia for third party claims arising from key asset failure for $5000 per annum. The AER accepts EnergyAustralia's self insurance premium for key assets failure of $2.68 million per annum.

Key person risk[1462]

The NSW DNSPs have proposed the following self insurance premiums for key person risk:

- Country Energy—$42 000 per annum
- EnergyAustralia—$219 000 per annum
- Integral Energy—$119 000 per annum.

Key person risk represents the risk that a DNSP could bear an adverse financial impact due to the 'sudden departure, or death', of a key employee.

Generally, key person insurance is available to a business to cover against business interruptions and costs arising from the sudden departure or death of a key employee. However, the NSW DNSPs have not retained any external insurance arrangements, choosing instead to self insure for exposure to key person risk.

EnergyAustralia and Integral Energy indicated that approximately 5 per cent of total employees were considered key employees. Country Energy indicated that approximately 24 per cent of its total employees were considered key employees. Country Energy stated that the high proportion of key employees reflected employment pressures as a result of an increasing demand for electricians and mechanics from other industry sectors.

The AER is not satisfied that a prudent operator would seek insurance for the sudden departure or death of such a large number of its employees and that the coverage of a simultaneous event of the magnitude of this type would be possible. Further, the analysis provided by SAHA is not supported by information concerning the history of sudden departure or death of employees from either the DNSPs or similar businesses.

Notwithstanding the above, it is noted that the self insurance premiums are calculated on the basis of the sudden departure or death of all key employees identified by the NSW DNSPs. The AER notes, however, that in any year it would be expected that only a fraction of these key employees would suddenly depart or die.

Based on the information provided, the AER considers that the proposed self insurance premiums for the sudden departure or death of key employees do not reflect

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[1462] SAHA, *Country Energy Self Insurance Risk Quantification,* pp. 92–96; SAHA, *Integral Energy Self Insurance Risk Quantification*, pp. 82–92; SAHA, *EnergyAustralia Self Insurance Risk Quantification*, pp. 92–98.

the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives.

Summary

The AER does not accept the self insurance premiums for key employees of $42 000 per annum for Country Energy, $219 000 per annum for EnergyAustralia and $119 000 per annum for Integral Energy.

General public liability risk[1463]

General public liability risk covers incidents where a DNSP is liable for injuries or other losses suffered by member(s) of the general public as a result of its (or its employees) negligence or fault. EnergyAustralia and Country Energy sought self insurance in relation to general public liability for claims above the existing external insurance deductible.[1464] Country Energy and EnergyAustralia have both proposed self insurance premiums of $9 000 per annum.

Whilst SAHA indicated that EnergyAustralia and Country Energy had not experienced any such claims, SAHA suggested that based on the experience of Integral Energy, there was a possibility of claims above the deductible.[1465] SAHA therefore calculated the probability of a general liability claim as 2 in 11 years for both DNSPs. SAHA chose this probability on the basis that it is 11 years since the inception of EnergyAustralia and Country Energy.

The AER considers that the basis for determining the probability of these events is not robust. In particular:

- Integral Energy's experience with above deductible general liability claims in the previous regulatory control period is not relevant to EnergyAustralia or Country Energy, because of differences between Integral Energy's network and circumstances and those of Country Energy and EnergyAustralia

- there is no rationale for the application of an 11 year period as the basis for the probability calculation because there is nothing inherently important about the inception date of the DNSPs.[1466] In addition, the AER notes that Country Energy was formed in 2001 (that is, 7 years ago in the context of the SAHA analysis).

As a result, based on the information provided, the AER rejects the associated self insurance premiums for both EnergyAustralia and Country Energy on the basis that the estimate of the probability of occurrence is not sufficiently robust to be used to calculate the self insurance allowances. The AER does not consider that the proposed self insurance allowances reflect the efficient costs that a prudent operator in the

[1463] SAHA, *Country Energy Self Insurance Risk Quantification,* pp. 78–80; SAHA, *EnergyAustralia Self Insurance Risk Quantification*, pp. 78–80.

[1464] Integral Energy did not seek a self insurance premium for general public liability risk.

[1465] SAHA indicated that Integral Energy experienced two such claims in the last regulatory control period.

[1466] Country Energy, *Regulatory proposal*, p. 13.

circumstances of EnergyAustralia and Country Energy would require to achieve the opex objectives.

Summary

The AER does not accept the proposed self insurance premiums for general public liability risk of $9000 per annum for Country Energy and EnergyAustralia.

Guaranteed service level (GSL) compensation [1467]

EnergyAustralia sought self insurance for GSL claims in relation to a major outage due to: bushfires started by EnergyAustralia's assets; aged asset failure; and unforeseeable human error. EnergyAustralia proposed a self insurance premium of $251 000 per annum.

SAHA calculated the probability of a major bushfire started by EnergyAustralia's assets based on the approach discussed above. The AER has rejected SAHA's calculation of the probability of a major bushfire started by EnergyAustralia's assets on the basis that it did not represent a robust assessment of bushfire risk.

In relation to aged asset failure, SAHA noted that since not all major asset failures will result in a catastrophic blackout, SAHA assumed a 'relatively rare occurrence' of this event at 1 in every 150 years. In relation to human error causing a catastrophic power failure, SAHA applied a 'relatively rare occurrence' of this event at 1 in every 300 years.

The AER notes that SAHA has provided no evidence in support of the proposed probabilities associated with asset failure or human error causing a catastrophic power failure. As such, based on the information provided, the AER considers that SAHA has not provided sufficient rationale for the proposed probabilities and they are not sufficiently robust to be used to calculate the premium. Therefore, the AER is not satisfied that the proposed self insurance premium for GSL compensation reasonably reflects the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives.

Summary

The AER does not accept the proposed self insurance premium for GSL compensation of $251 000 per annum for EnergyAustralia.

AER conclusion

For the reasons set out above, the AER is not satisfied that SAHA has provided robust analysis which supports the probability of certain events occurring or that the costs of those events are reasonable. Accordingly it has not accepted the calculation of the self insurance premiums.

The AER considers that the proposed self insurance allowances do not reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to meet the opex objectives.

[1467] *EnergyAustralia Self Insurance Risk Quantification*, pp. 135–149.

As a result of its analysis of the information provided the AER is satisfied that the revised estimates of the total self insurance allowances for the next regulatory control period set out in table R.1, based on the above accepted self insurance premiums, reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives.

Table R.1: AER's conclusion on self insurance allowances for the DNSPs over the next regulatory control period ($m, 2008−09)

	Country Energy		EnergyAustralia		Integral Energy	
	Proposal	AER conclusion	Proposal	AER conclusion	Proposal	AER conclusion
Total self insurance	19.5	15.0	29.5	20.4	16.3	9.6

Note: EnergyAustralia's self insurance premiums in its regulatory proposal are in 2007−08 dollar terms. The AER converted these to 2008–09 dollar terms using EnergyAustralia's proposed 2.7 per cent escalation.

Appendix S: Analysis of EnergyAustralia's modelling of the EBSS

This appendix sets out the AER analysis of the EBSS scenarios modelled by EnergyAustralia in attachment 14.4 to its regulatory proposal.

AER considerations

As noted by EnergyAustralia, the outcomes of modelling the EBSS will be sensitive to assumptions made regarding subsequent regulatory control periods. EnergyAustralia's analysis assumes that actual opex during the second and third regulatory control period is equal to the forecast opex for those periods. EnergyAustralia argued that this assumption is necessary to 'quarantine the immediate and lagged outcomes that the EBSS will generate based purely on expenditure profiles within the period of interest'.[1468]

The AER considers that this assumption does not achieve its stated aim of isolating the impacts of efficiency gains or losses made in a single regulatory control period. The AER notes that the EBSS is an incremental scheme and that opex is largely recurrent. By assuming that actual opex during the second and third regulatory control period is equal to the forecast opex for those periods an efficiency gain or loss would result in year six (the start of the following regulatory control period) if forecast opex in regulatory control periods two and three differs from actual opex in year five. By illustration, in EnergyAustralia's first example the DNSP makes an efficiency gain of $10.55 in year six because of EnergyAustralia's assumption. Thus, by making this assumption, the analysis will not be of efficiency gains made in a single regulatory control period only. The AER considers that to analyse only those efficiency gains or losses made in a single regulatory control period it should be assumed that actual opex in subsequent regulatory control periods is equal to actual opex in the final year of the period being analysed.

Regardless of the assumption made in relation to subsequent regulatory control periods, the AER considers that the outcome of the EBSS is appropriate in both the examples provided by EnergyAustralia.

EnergyAustralia example one

In EnergyAustralia's first example an overspend of $5.44—in net present value (NPV) terms—in the first regulatory control period results in an overall NPV positive benefit of $16.99 to the DNSP. EnergyAustralia argued that this result is 'directionally inappropriate' and delivers an inappropriate sharing of gains and losses.[1469] This example is replicated in table S.1 below (it should be noted that the example does not exactly match EnergyAustralia's example due to rounding).

To assess whether the EBSS outcomes are appropriate the AER considers that the total benefit from the realised efficiency gains, and how they are shared between the DNSP and consumers, should be considered. The total benefit in a given year is equal

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[1468] EnergyAustralia, *Regulatory proposal*, attachment 14.4, p. 3.
[1469] EnergyAustralia, *Regulatory proposal*, attachment 14.4, p. 4.

to the difference between the opex that would be expended if no efficiency gains were realised and the actual opex expended in that year. In example one the total benefit is negative in years one, two three and five because the DNSP overspends in those years. However, in each year from year six onward the total benefit is $4.77 (due to the assumptions made by EnergyAustralia regarding opex in subsequent periods). The total benefit from year m onward can be calculated as:

$$\text{Discounted benefit from year m onward} = \sum_{n=m}^{\infty} \frac{B_n}{(1+r)^{n-1}} = \frac{B_n}{r(1+r)^{m-2}}$$

Where:

B_n = the benefit in year n

r = the discount rate

Consequently the discounted total benefit from year six to perpetuity is equal to $62.97. Adding this to the discounted total benefit for years one to five the discounted total benefit for example one is calculated to be $57.53.

The benefit to the DNSP will be equal to the target for pricing purposes (which equals forecast opex plus any carryover amount) minus the actual opex in that year. The DNSP in example one receives a negative benefit in years one, two, three and five due to overspending in those years. In years six, seven, eight, nine and eleven it generates a positive benefit from carryover payments. Thus the discounted DNSP benefit can be calculated as $16.97, which represents 30 per cent of the discounted total benefit.

The benefit to consumers will be equal to the opex that would be expended if no efficiency gains were realised minus the target for pricing purposes. Consumers receive a negative benefit in years seven, eight, nine and eleven due to the payment of carryover amounts to the DNSP. However, from year 12 onward consumers receive an ongoing benefit of $4.77 each year due the ongoing efficiency gain made by the DNSP in year six. Using the equation above the discounted consumer benefit can be calculated as $40.56, which represents 70 per cent of the discounted total benefit.

Accordingly, it can be shown that the EBSS has distributed the efficiency gains made between the DNSP and consumers based on a 30:70 sharing ratio. The AER recognises that, in example one, the DNSP receives a positive benefit despite overspending in the first regulatory control period. However, the AER considers that this outcome is the result of the ongoing efficiency gain made in year six and that the distribution of total benefits is appropriate.

EnergyAustralia example two

In EnergyAustralia's second example an underspend of $1.32 in the first regulatory control period results in an overall NPV negative benefit of $15.88 to the DNSP. EnergyAustralia argued that this outcome is also 'directionally inappropriate' and is 'clearly damaging' because the DNSP has received negative carryover amounts despite spending less than the target opex in the first regulatory control period.

As demonstrated in table S.2, the total benefit to the DNSP and consumers in example two is –$53.85. A significant driver of this result is the ongoing efficiency loss made in year six which results in a loss of $4.18 in each year from year six onward. The benefits to the DNSP and consumers are –$15.89 and –$37.96 respectively, which corresponds to a sharing ratio of 30:70. The AER considers it appropriate that the DNSP face a net loss in this example, despite underspending in the first regulatory control period, because the significant ongoing efficiency loss from year six onward delivers a negative discounted total benefit. The AER notes that if it is assumed that there is no efficiency loss in year six the result is positive for the DNSP, and for consumers (see table S.3).

Table S.1: Analysis of EnergyAustralia's analysis of the EBSS, example one

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	NPV
Target (F)	100.00	100.00	100.00	100.00	100.00	95.23	95.23	95.23	95.23	95.23	95.23	95.23	95.23	95.23	95.23	
Actual (A)	100.40	100.81	104.16	95.23	105.78	95.23	95.23	95.23	95.23	95.23	95.23	95.23	95.23	95.23	95.23	
Cumulative saving (F-A)	–0.40	–0.81	–4.16	4.77	–5.78	0	0	0	0	0	0	0	0	0	0	
Incremental saving (E)	–0.40	–0.41	–3.35	8.93	0	10.55	0	0	0	0	0	0	0	0	0	
Carry–over of gains made in																
1		–0.40	–0.40	–0.40	–0.40	–0.40										
2			–0.41	–0.41	–0.41	–0.41	–0.41									
3				–3.35	–3.35	–3.35	–3.35	–3.35								
4					8.93	8.93	8.93	8.93	8.93							
5						0	0	0	0	0						
6							10.55	10.55	10.55	10.55	10.55					
7								0	0	0	0	0				
8									0	0	0	0	0			
9										0	0	0	0	0		
10											0	0	0	0	0	
Carry–over						4.77	5.17	5.58	8.93	0	10.55	0	0	0	0	
Target, no gains	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	
Target for pricing purposes	100.00	100.00	100.00	100.00	100.00	100.00	100.40	100.81	104.16	95.23	105.78	95.23	95.23	95.23	95.23	
DNSP benefit	–0.40	–0.81	–4.16	4.77	–5.78	4.77	5.17	5.58	8.93	0	10.55	0	0	0	0	
Consumer benefit	0	0	0	0	0	0	–0.40	–0.81	–4.16	4.77	–5.78	4.77	4.77	4.77	4.77	
Total Benefit	–0.40	–0.81	–4.16	4.77	–5.78	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.77	4.77	
Discount factor	1.00	0.94	0.89	0.84	0.79	0.75	0.70	0.67	0.63	0.59	0.56	0.53	0.50	0.47	0.44	
PV carry–over	0	0	0	0	0	3.56	3.64	3.71	5.60	0	5.89	0	0	0	0	22.40
PV DNSP benefit	–0.40	–0.76	–3.70	4.00	–4.58	3.56	3.64	3.71	5.60	0	5.89	0	0	0	0	16.97
PV benefit to consumers	0	0	0	0	0	0	–0.28	–0.54	–2.61	2.82	–3.23	2.51	2.37	2.24	2.11	40.56
PV total benefit	–0.40	–0.76	–3.70	4.00	–4.58	3.56	3.36	3.17	2.99	2.82	2.66	2.51	2.37	2.24	2.11	57.73

Note: Assumes a real discount rate of 6%.
Source: EnergyAustralia, *Regulatory proposal*, Attachment 14.4, p. 4, and AER analysis.

Table S.2: Analysis of EnergyAustralia's analysis of the EBSS, example two

Year	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	NPV
Target (F)	100.00	100	100	100	100	104.18	104.18	104.18	104.18	104.18	104.18	104.18	104.18	104.18	104.18	
Actual (A)	100.69	98.50	97.12	104.18	98.04	104.18	104.18	104.18	104.18	104.18	104.18	104.18	104.18	104.18	104.18	
Cumulative saving (F–A)	–0.69	1.5	2.88	–4.18	1.96	0	0	0	0	0	0	0	0	0	0	
Incremental saving (E)	–0.69	2.19	1.38	–7.06	0	–6.14	0	0	0	0	0	0	0	0	0	
Carry–over of gains made in																
1		–0.69	–0.69	–0.69	–0.69	–0.69										
2			2.19	2.19	2.19	2.19	2.19									
3				1.38	1.38	1.38	1.38	1.38								
4					–7.06	–7.06	–7.06	–7.06	–7.06							
5						0	0	0	0	0						
6							–6.14	–6.14	–6.14	–6.14	–6.14					
7								0	0	0	0	0				
8									0	0	0	0	0			
9										0	0	0	0	0		
10											0	0	0	0	0	
Carry–over						–4.18	–3.49	–5.68	–7.06	0	–6.14	0	0	0	0	
Target, no gains	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	
Target for pricing purposes	100	100	100	100	100	100	100.69	98.5	97.12	104.18	98.04	104.18	104.18	104.18	104.18	
DNSP benefit	–0.69	1.5	2.88	–4.18	1.96	–4.18	–3.49	–5.68	–7.06	0	–6.14	0	0	0	0	
Consumer benefit	0	0	0	0	0	0	–0.69	1.5	2.88	–4.18	1.96	–4.18	–4.18	–4.18	–4.18	
Total Benefit	–0.69	1.5	2.88	–4.18	1.96	–4.18	–4.18	–4.18	–4.18	–4.18	–4.18	–4.18	–4.18	–4.18	–4.18	
Discount factor	1	0.94	0.89	0.84	0.79	0.75	0.70	0.67	0.63	0.59	0.56	0.53	0.50	0.47	0.44	
PV carry–over	0	0	0	0	0	–3.12	–2.46	–3.78	–4.43	0	–3.43	0	0	0	0	–17.22
PV DNSP benefit	–0.69	1.42	2.56	–3.51	1.55	–3.12	–2.46	–3.78	–4.43	0	–3.43	0	0	0	0	–15.89
PV benefit to consumers	0	0	0	0	0	0	–0.49	1.00	1.81	–2.47	1.09	–2.20	–2.08	–1.96	–1.85	–37.96
PV total benefit	–0.69	1.42	2.56	–3.51	1.55	–3.12	–2.95	–2.78	–2.62	–2.47	–2.33	–2.20	–2.08	–1.96	–1.85	–53.85

Note: Assumes a real discount rate of 6%.

Source: EnergyAustralia, *Regulatory proposal*, attachment 14.4, p. 5, and AER analysis.

Table S.3: Analysis of EnergyAustralia's analysis of the EBSS, example two with no efficiency gain in year 6

Year	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**NPV**
Target (F)	100	100	100	100	100	104.18	104.18	104.18	104.18	104.18	98.04	98.04	98.04	98.04	98.04	
Actual (A)	100.69	98.5	97.12	104.18	98.04	98.04	98.04	98.04	98.04	98.04	98.04	98.04	98.04	98.04	98.04	
Cumulative saving (F–A)	–0.69	1.5	2.88	–4.18	1.96	6.14	6.14	6.14	6.14	6.14	0	0	0	0	0	
Incremental saving (E)	–0.69	2.19	1.38	–7.06	0	0	0	0	0	0	0	0	0	0	0	
Carry–over of gains made in																
1		–0.69	–0.69	–0.69	–0.69	–0.69										
2			2.19	2.19	2.19	2.19	2.19									
3				1.38	1.38	1.38	1.38	1.38								
4					–7.06	–7.06	–7.06	–7.06	–7.06							
5						0	0	0	0	0						
6							0	0	0	0	0					
7								0	0	0	0	0				
8									0	0	0	0	0			
9										0	0	0	0	0		
10											0	0	0	0	0	
Carry–over						–4.18	–3.49	–5.68	–7.06	0	0	0	0	0	0	
Target, no gains	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	
Target for pricing purposes	100	100	100	100	100	100	100.69	98.5	97.12	104.18	98.04	98.04	98.04	98.04	98.04	
DNSP benefit	–0.69	1.5	2.88	–4.18	1.96	1.96	2.65	0.46	–0.92	6.14	0	0	0	0	0	
Consumer benefit	0	0	0	0	0	0	–0.69	1.5	2.88	–4.18	1.96	1.96	1.96	1.96	1.96	
Total Benefit	–0.69	1.5	2.88	–4.18	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	1.96	
Discount factor	1	0.94	0.89	0.84	0.79	0.75	0.70	0.67	0.63	0.59	0.56	0.53	0.50	0.47	0.44	
PV carry–over	0	0	0	0	0	–3.12	–2.46	–3.78	–4.43	0	0	0	0	0	0	–13.79
PV DNSP benefit	–0.69	1.42	2.56	–3.51	1.55	1.46	1.87	0.31	–0.58	3.63	0	0	0	0	0	8.03
PV benefit to consumers	0	0	0	0	0	0	–0.49	1.00	1.81	–2.47	1.09	1.03	0.97	0.92	0.87	19.18
PV total benefit	–0.69	1.42	2.56	–3.51	1.55	1.46	1.38	1.30	1.23	1.16	1.09	1.03	0.97	0.92	0.87	27.21

Note: Assumes a real discount rate of 6%.

Appendix T: EnergyAustralia pricing methodology

EnergyAustralia

Attachment 4.1	EnergyAustralia's Transmission Pricing Methodology

REVIEW

Responsibility	Name	Date
Author	C Amos	19 May 2008
Reviewer		

Approval	Name	Signature	Date
EM-NR&P	H. Colebourn		23 May 2008

EnergyAustralia's Proposed Transmission Pricing Methodology

1 July 2009 to 30 June 2014

2 June 2008

Table of Contents

1 Introduction

EnergyAustralia provides both transmission and distribution services to a defined geographic area within NSW. This document outlines EnergyAustralia's proposed transmission *pricing methodology*, and is separate to the pricing proposal required to be submitted to the AER for distribution pricing under Chapter 11 and Appendix 1 to the National Electricity Rules (the transitional rules).

This pricing methodology directly reflects the *pricing principles for prescribed transmission services* set out in clause 6A.23 of the National Electricity Rules. This standardised approach has been developed to conform with the steps and sequence set out in the Rules. EnergyAustralia has not proposed any alternative arrangements for its transmission *pricing methodology*.

This pricing methodology is to apply from 1 July 2009 to 30 June 2014.

1.1 *Interpretation*

All terms in this proposed *transmission pricing methodology* that are italicised have the meaning given to them in the *transmission pricing methodology guidelines* or, where no definition is provided in that document, *the Rules*.

A reference to *the Rules* is taken to be a reference to the current version of the National Electricity Rules.

1.2 *Prescribed Transmission Services*

EnergyAustralia's proposed *transmission pricing methodology* relates to the provision of *prescribed transmission services*, referred to as EnergyAustralia prescribed (transmission) standard control services under clause 6.1.6 of the transitional rules. These services include:

- Shared transmission services provided to customers directly connected to the transmission network and connected network service providers (*prescribed TUoS services*);
- Connection services provided to connect EnergyAustralia distribution network to the transmission network (*prescribed exit services*);
- Grandfathered connection services provided to generators and customers directly connected to the transmission network that were in place or committed to be in place on 9 February 2006 (*prescribed entry services* and *prescribed exit services*); and
- Services required under *the Rules* or in accordance with jurisdictional electricity legislation that are necessary to ensure the integrity of the transmission network, including through the maintenance of power system security and assisting in the planning of the power system (*prescribed common transmission services*).

This proposed transmission *pricing methodology* does not relate to the provision of *negotiated transmission services* (referred to as negotiated distribution services under clause 6.1.6 of the transitional rules) provided by EnergyAustralia.

1.3 *Rules Requirement*

Clause 6A.24.1 of *the Rules* states that the *transmission pricing methodology* is a methodology, formula, process or approach that when applied by a TNSP:

(1) allocates the aggregate annual revenue requirement (AARR) for prescribed transmission services to:

  (i) the *categories of prescribed transmission services* for that provider; and

(ii) *transmission network connection points* of *Transmission Network Users*; and

(2) determines the structure of the prices that a *Transmission Network Service Provider* may charge for each of the *categories of prescribed transmission services* for that provider.

The Rules also require that the *transmission pricing methodology* satisfy principles and guidelines established by *the Rules*. In particular, clause 6A.10.1(e) of *the Rules* requires that the proposed *transmission pricing methodology* must:

(1) give effect to and be consistent with the *Pricing Principles for Prescribed Transmission Services* (that is to say, the principles set out in rule 6A.23); and

(2) comply with the requirements of, and contain or be accompanied by such information as is required by, the *transmission pricing methodology guidelines* made for that purpose under rule 6A.25.

2 Transmission Pricing Methodology Guideline Requirements

2.1 *Co-ordinating Network Service Provider*

In accordance with clause 6A.29.1 of *the Rules*, TransGrid is the *Co-ordinating Network Service Provider* for NSW. As at May 2008, for the purposes of transmission pricing there are four TNSPs in NSW. EnergyAustralia is required to annually provide TransGrid with a revised model of EnergyAustralia's transmission network, with the approved AARR for its *transmission system* already allocated in accordance with this transmission pricing proposal. EnergyAustralia is also required to provide any other information reasonably required by TransGrid to ensure the proper calculation of prescribed transmission prices in New South Wales. Note also that:

- the calculation of the postage stamp rates which form part of transmission prices referred to in the AER Guidelines at 2.1(h); and
- prudent discounts referred to in the AER Guidelines at 2.1(k) are also calculated as part of the postage stamp allocation;

are calculated by the coordinating TNSP, TransGrid.

2.2 *Summary of Proposal*

The AER's transmission *pricing methodology guidelines* supplement and elaborate on the pricing principles contained in Chapter 6A of *the Rules* in so far as they specify or clarify:

- the information that is to accompany a proposed transmission *pricing methodology*;
- permitted pricing structures for the recovery of the locational component of providing *prescribed TUoS services*;
- permitted postage stamp pricing structures for *prescribed common transmission services* and the recovery of the adjusted non-locational component of providing *prescribed TUoS services*;
- the types of *transmission system* assets that are *directly attributable* to each category of *prescribed transmission services*; and
- those parts of a proposed *transmission pricing methodology*, or the information accompanying it that will not be publicly disclosed without the consent of the TNSP.

As EnergyAustralia is an *appointing provider* of transmission services in NSW, this transmission *pricing methodology* is limited to:

- Calculation of the Annual Aggregate Revenue Requirement for each year of the regulatory control period;
- Proposing a methodology to determine whether assets fall in to the categories of exit, entry, shared or common service;
- Allocating the AARR to those asset classes of exit, entry, shared and common service, using an attributable cost share method, to determine an Annual Service Revenue Requirement (ASRR) for each asset class;
- Allocating the ASRR of each asset class to the specific assets within that asset class;
- Detailing the methodology for implementation of the priority ordering approach under clause 6A.23.2(d) of the Rules including two worked examples;
- Billing arrangements for a small number of direct connected transmission customers
- Management of prudential requirements and prudent discounts for new or existing connections to the EnergyAustralia transmission network;
- Describing how asset costs which are associated with prescribed entry services and prescribed exit services at a connection point, which may be attributable to multiple transmission network users, will be allocated; and
- Detail how EnergyAustralia intends to monitor and develop records of its compliance with its approved transmission *pricing methodology*, the pricing principles for *prescribed transmission services* (clause 6A.23) and part J of *the Rules* in general.

Elements of a *pricing methodology* that are required as part of the AER guidelines and National Electricity Rules that are carried out by TransGrid on behalf of EnergyAustralia are:

- any adjustments required to be made to the locational component of the ASRR as required in the Rules[1].
- any adjustments required to be made to the pre-adjusted non-locational component of the ASRR as required in the Rules[2].
- allocation of the locational component of prescribed TUoS services to transmission connection points.
- establishing structure and price for common service, general, and locational charges at each of EnergyAustralia's transmission connection points[3].

3 Proposed Transmission Pricing Methodology

3.1 *Transitional Arrangements applicable to EnergyAustralia for the 2009-14 Regulatory Period*

Chapter 11 of the *Rules* provides Transitional Rules in relation to the economic regulations of distribution services in NSW and the ACT for the 2009-14 regulatory period. Clause 6.1.6 of the Transitional Rules applies the pricing rules in Part J of Chapter 6 to EnergyAustralia's prescribed (transmission) standard control services. This clause further provides that Part J applies as if reference

[1] Rules, clause 6A.23(c)(1)

[2] Rules, clause 6A.23(c)(2)

[3] That is, EnergyAustralia transmission connection points that supply EnergyAustralia's distribution network, not to be confused with TransGrid connection points that supply EnergyAustralia's distribution network.

to "prescribed distribution services" were references to EnergyAustralia prescribed (transmission) standard control services and the reference in clause 6A.22.1 to clause 6A.3.2 were a reference to rules 6.6 and 6.13.

Clause 6.8.2(c)(9) of the Transitional Rules requires EnergyAustralia to submit a proposed pricing methodology to the Australian Energy Regulator (AER) as part of its regulatory proposal submitted to the AER.

3.2 *Aggregate Annual Revenue Requirement*

The Aggregate Annual Revenue Requirement (AARR) is calculated in accordance with clause 6A.22.1 of *the Rules* as:

> "the *maximum allowed revenue* referred to in clause 6A.3.1 adjusted:
>
> (1) in accordance with clause 6A.3.2, and
>
> (2) by subtracting the operating and maintenance costs expected to be incurred in the provision of *prescribed common transmission services*."

Clause 6A.3.1 in turn operates so that the revenue that may be earned in any regulatory year of a regulatory control period from the provision of EnergyAustralia prescribed (transmission) services is the maximum allowed revenue subject to any adjustments referred to in clause 6.6 and 6.13 of the Transitional Rules and is to be determined in accordance with the applicable determination.

EnergyAustralia will therefore take the annual aggregate revenue requirement determined by the AER with respect to EnergyAustralia prescribed (transmission) services and (following the apportionment required by clause 6.12.1A of the Transitional Rules) and adjusting that amount in accordance with:

(1) Rules 6.6. (relating to adjustments after the making of a building block determination); and

(2) Rule 6.13 (relating to revocation); and

(3) Subtracting the operating and maintenance costs expected to be incurred in the provision of *prescribed common transmission services*.

The costs referred in (3) above are derived from budget projections and include:

- network switching and operations;
- administration and management of the business;
- network planning and development; and
- general overheads.

3.3 *Categories of Service*

EnergyAustralia's AARR is recovered from transmission charges for the following categories of transmission service:

- *Prescribed exit services* which include assets that are fully dedicated to serving a Transmission Customer or group of Transmission Customers at a single connection point and: (a) are deemed prescribed by virtue of the operation of clause 11.6.11 of *the Rules*; or (b) are provided to Network Service Providers at the boundary of the prescribed transmission network;
- *Prescribed transmission use of system (TUoS) services* which include assets that are shared to a greater or lesser extent by all users across the *transmission system* and are not *prescribed common transmission services, prescribed entry services or prescribed exit services*; and
- *Prescribed common transmission services*, which are services that benefit all Transmission Customers and cannot be reasonably allocated on a locational basis.

to "prescribed distribution services" were references to EnergyAustralia prescribed (transmission) standard control services and the reference in clause 6A.22.1 to clause 6A.3.2 were a reference to rules 6.6 and 6.13.

Clause 6.8.2(c)(9) of the Transitional Rules requires EnergyAustralia to submit a proposed pricing methodology to the Australian Energy Regulator (AER) as part of its regulatory proposal submitted to the AER.

3.2 *Aggregate Annual Revenue Requirement*

The Aggregate Annual Revenue Requirement (AARR) is calculated in accordance with clause 6A.22.1 of *the Rules* as:

> "the *maximum allowed revenue* referred to in clause 6A.3.1 adjusted:
>
> (1) in accordance with clause 6A.3.2, and
>
> (2) by subtracting the operating and maintenance costs expected to be incurred in the provision of *prescribed common transmission services*."

Clause 6A.3.1 in turn operates so that the revenue that may be earned in any regulatory year of a regulatory control period from the provision of EnergyAustralia prescribed (transmission) services is the maximum allowed revenue subject to any adjustments referred to in clause 6.6 and 6.13 of the Transitional Rules and is to be determined in accordance with the applicable determination.

EnergyAustralia will therefore take the annual aggregate revenue requirement determined by the AER with respect to EnergyAustralia prescribed (transmission) services and (following the apportionment required by clause 6.12.1A of the Transitional Rules) and adjusting that amount in accordance with:

(1) Rules 6.6. (relating to adjustments after the making of a building block determination); and

(2) Rule 6.13 (relating to revocation); and

(3) Subtracting the operating and maintenance costs expected to be incurred in the provision of *prescribed common transmission services*.

The costs referred in (3) above are derived from budget projections and include:

- network switching and operations;
- administration and management of the business;
- network planning and development; and
- general overheads.

3.3 *Categories of Service*

EnergyAustralia's AARR is recovered from transmission charges for the following categories of transmission service:

- *Prescribed exit services* which include assets that are fully dedicated to serving a Transmission Customer or group of Transmission Customers at a single connection point and: (a) are deemed prescribed by virtue of the operation of clause 11.6.11 of *the Rules*; or (b) are provided to Network Service Providers at the boundary of the prescribed transmission network;
- *Prescribed transmission use of system (TUoS) services* which include assets that are shared to a greater or lesser extent by all users across the *transmission system* and are not *prescribed common transmission services, prescribed entry services or prescribed exit services*; and
- *Prescribed common transmission services*, which are services that benefit all Transmission Customers and cannot be reasonably allocated on a locational basis.

EnergyAustralia does not currently have any assets providing entry services to a generator. However, this proposal outlines EnergyAustralia's proposed methodology with respect to the allocation of these services in anticipation of this service being required. *Prescribed entry services* include assets that are fully dedicated to serving a Generator or group of Generators at a single connection point.

3.4 Cost Allocation

The first step in calculating prescribed transmission service prices is to classify each asset utilised in the provision of *prescribed transmission services* into one of the above categories of service. The delineation between the assets that provide *prescribed entry services*, *prescribed exit services*, *prescribed TUoS services* and *prescribed common transmission services* is set out in clause 2.4 of the *transmission pricing methodology guidelines*.

The cost allocation process assigns the optimised replacement cost (ORC)[4] of all prescribed assets to either *prescribed common transmission services* (assets that benefit all transmission customers) or individual network branches (transmission lines and transformers). Each branch is then defined as entry, exit or shared network. This process of cost allocation is explained in more detail in Appendix A.

3.5 Calculation of the attributable cost share for each category of service

The second step in calculating prescribed transmission service prices is the calculation of the attributable cost shares. The attributable cost share for each category of service is calculated in accordance with clause 6A.22.3 of *the Rules* as the ratio of:

- the costs of the *transmission system* assets *directly attributable* to the provision of that category of *prescribed transmission services* (as determined in 6.5 above); to
- the total costs of all the TNSP's *transmission system* assets *directly attributable* to the provision of *prescribed transmission services* (as determined in 6.5 above).

For example, if the ORCs of prescribed services assets have been allocated to the applicable categories of *prescribed transmission services* as shown in Table 1 then the attributable costs shares are calculated as:

$$\text{Attributable Cost Share}_{EXIT} = ORC_{EXIT} / ORC_{TOTAL}$$
$$= \$6,972,222 / \$43,050,000$$
$$= 0.162$$

with the attributable cost shares of the other categories calculated in the same manner as shown in Table 2.

[4] Consistent with clause 6A.22.3(b) of the Rules

Table 1: Costs allocated to categories of prescribed transmission services

Category	ORC
Exit service	6,972,222
Entry service	1,761,111
TUoS service	33,566,667
Common Service	750,000
Total	43,050,000

Table 2: Attributable Cost Shares

Category	ORC	Attributable Cost Share
Exit service	6,972,222	0.162
Entry service	1,761,111	0.041
TUoS service	33,566,667	0.780
Common Service	750,000	0.017
Total	43,050,000	1.000

3.6 *Calculation of the Annual Service Revenue Requirement (ASRR)*

The third step in calculating prescribed transmission service prices is to allocate the AARR to each category of prescribed transmission service in accordance with the attributable cost share for each such category of services.

This allocation results in the annual service revenue requirement (ASRR) for that category of services.

Assuming an AARR of $2,504,434 and applying the attributable cost shares determined above the ASRR for each category of prescribed services is calculated as:

$$ASRR_{EXIT} = AARR \times \text{Attributable Cost Share}_{EXIT}$$
$$= \$2,504,434 \times 0.162$$
$$= \$405,609$$

with the ASRRs of the other categories calculated in the same manner.

Table 3 Annual Service Revenue Requirements

Category	Attributable Cost Share	Annual Service Revenue Requirement (ASRR)
Exit Service	0.162	405,609
Entry Service	0.041	102,453
TUoS Service	0.780	1,952,741
Common Service	0.017	43,631
Total	1.000	2,504,434

3.7 *Allocation of the ASRR to transmission network connection points*

The fourth step in calculating prescribed transmission service prices is to allocate the ASRR for *prescribed entry services*, *prescribed exit services* and *prescribed TUoS services* to each transmission network connection point in accordance with the principles of clause 6A.23.3 of *the Rules*.

3.7.1 Prescribed entry services

The whole of the ASRR for *prescribed entry services* is allocated to transmission network connection points in accordance with the attributable connection point cost share for *prescribed entry services* that are provided by the TNSP at that connection point.

The attributable connection point cost share for *prescribed entry services* is the ratio of the costs of the *transmission system* assets *directly attributable* to the provision of *prescribed entry services* at that transmission network connection point to the total costs of all the TNSP's *transmission system* assets *directly attributable* to the provision of *prescribed entry services*.

For example, consider two generators, Gen A1 and Gen A2 that receive *prescribed entry services* and the cost allocation methodology has allocated the ORCs of assets *directly attributable* to entry services to them as shown in Table 4:

$$\text{Attributable Connection Point Cost Share}_{GEN\ A1} = ORC_{GEN\ A1} / ORC_{ENTRY}$$
$$= \$1,033,333 / \$1,761,111$$
$$= 0.587$$

The attributable connection point cost shares of the other generator is calculated in the same manner as shown in Table 5

Table 4: Prescribed entry services ORCs

Entry	ORC
Gen A1	1,033,333
Gen A2	727,778
Total ORC of prescribed entry assets	1,761,111

Table 5: Attributable connection point cost shares

Entry	ORC	Attributable connection point cost share
Gen A1	1,033,333	0.587
Gen A2	727,778	0.413
Total	1,761,111	1.000

The ASRR allocated to the Gen A1 transmission network connection point is calculated as follows:

$$ASRR_{GEN\ A1} = ASRR_{ENTRY} \times \text{Attributable connection point cost share}_{GEN\ A1}$$
$$= \$102,453 \times 0.587$$
$$= \$60,114$$

The ASRR of the other generator connection points is calculated in the same manner.

Table 6: Connection point ASRRs (Entry)

Entry	ORC	Attributable connection point cost share	Connection point ASRR
Gen A1	1,033,333	0.587	60,114
Gen A2	727,778	0.413	42,338
Total	1,761,111	1.000	102,453

The ASRR related to the entry assets for each generator is recovered via a daily fixed charge. For example GEN A1 will be charged a daily rate of:

GEN A1 Fixed Charge = \$60,144/365 days[5]
= \$226.96/ day for the relevant financial year

No other charges will be applied to generators, as the transmission network is built for load, rather than generation. Common services and TUoS services are therefore allocated to loads.

3.7.2 Prescribed exit services

The whole of the ASRR for *prescribed exit services* is allocated to transmission network connection points in accordance with the attributable connection point cost share for *prescribed exit services* that are provided by the TNSP at that connection point.

The attributable connection point cost share for *prescribed exit services* is the ratio of the costs of the *transmission system* assets *directly attributable* to the provision of *prescribed exit services* at that transmission network connection point to the total costs of all the *transmission system* assets *directly attributable* to the provision of *prescribed exit services.*

The ASRRs of the prescribed exit connection points are calculated in the same manner as for the entry connection points.

Table 7: Connection point ASRRs (Exit)

Exit	*ORC*	*Attributable connection point cost share*	*Connection point ASRR*
Load A1	2,083,333	0.299	121,198
Load A2	1,405,556	0.202	81,768
Load B1	2,633,333	0.378	153,194
Load C1	850,000	0.122	49,449
Total	6,972,222	1.000	405,609

The ASRR related to the exit assets for each load is recovered via a daily fixed charge. For example Load A1 will be charged a daily rate of:

Load A1 Fixed Charge = \$121,198/365 days[6]
= \$332.05 per day for the relevant financial year

Locational charges, TUoS general charges and common service charges will also apply to Load A1, and are calculated by TransGrid as the Co-ordinating TNSP appointed by EnergyAustralia.

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[5] 366 days used for this calculation if a leap year

[6] 366 days used for this calculation if a leap year

3.7.3 Prescribed Transmission Use of System (TUoS) services

The prescribed TUoS (shared network) services ASRR is recovered from:

- *Prescribed TUoS services* (locational component); and
- *Prescribed TUoS services* (the adjusted non-locational component).

Clause 6A.23.3(c)(1) of *the Rules* requires that:

> "a share of the ASRR (the locational component) is to be adjusted by subtracting the estimated *auction amounts* expected to be distributed to the TNSP under clause 3.18.4 from the *connection points* for each relevant *directional interconnector* and this adjusted share is to be allocated as between such *connection points* on the basis of the estimated proportionate use of the relevant *transmission system* assets by each of those customers, and the *CRNP methodology* and *modified CRNP methodology* represent two permitted means of estimating proportionate use".

In NSW, compliance with this clause is carried out by TransGrid as the co-ordinating TNSP as EnergyAustralia is not a direct recipient of auction amounts. TransGrid makes relevant adjustments to account for auction amounts in it's pricing methodology consistent with clause 6A.23.3(c)(1). Please refer to TransGrid's *transmission pricing methodology* with respect to compliance with this clause.

Allocation of the locational component of prescribed TUoS services is carried out by TransGrid using the CRNP methodology, which assigns a proportion of shared network costs to individual customer connection points. TransGrid does this using the TPRICE *Cost Reflective Network Pricing* software used by most TNSPs in the NEM. Details on this calculation can be found in TransGrid's *transmission pricing proposal*.

The CRNP methodology requires three sets of input data:

- An electrical (loadflow) model of the network;
- A cost model of the network (the results of the cost allocation process described in Appendix A); and
- An appropriate set of load/generation patterns.

The remainder of the ASRR (the pre-adjusted non-locational component) is to be adjusted:

- by subtracting the amount (if any) referred to in clause 6A.23.3(e) of *the Rules*;
- by subtracting or adding any remaining settlements residue (not being settlements residue referred to in the determination of the locational component but including the portion of settlements residue due to intra-regional loss factors) which is expected to be distributed or recovered (as the case may be) to or from the TNSP in accordance with clause 3.6.5(a) of *the Rules*;
- for any over-recovery amount or under-recovery amount from previous years;
- for any amount arising as a result of the application of clause 6A.23.4(h) and (i) of *the Rules*; and
- for any amount arising as a result of the application of prudent discounts in accordance with clause 6A.26.1(d)-(g) of *the Rules*

These adjustments are carried out by TransGrid as the Co-ordinating TNSP in NSW. EnergyAustralia provides advice to TransGrid of any expected under-recovery or over-recovery amount from previous years to be used by TransGrid in setting prices each year.

3.7.4 Costs that could be allocated to more than one category of service

EnergyAustralia allocates substation costs that are *directly attributable* to entry, exit, common and TUoS services and then allocates the residual costs, known as substation local costs, to entry, exit and TUoS services on the basis of the number of pricing branches (transmission lines and transformers) connected to that substation.

Clause 6A.23.2(d) of *the Rules* has a priority ordering concept for the allocation of those costs which could be attributable to more than one category of *prescribed transmission services*.

The substation local costs are allocated to the various prescribed services in accordance with the provisions of clause 6A.23.2(d) of *the Rules* having regard to the stand alone costs associated with the provision of *prescribed TUoS services* and *prescribed common transmission services* with the remainder being allocated to *prescribed entry and prescribed exit services*.

Details on EnergyAustralia's application of priority ordering can be found in Appendix A.

3.8 *Provision for relaxation of TUoS locational side constraints*

The implementation of clause 6A.23.4(g)of *the Rules* allows for the relaxation of the 2% side constraint for material changes in connection point load or renegotiation of connection agreements, subject to AER approval.

In the event that a Transmission Customer requests a material increase in demand at an existing connection point, EnergyAustralia, together with TransGrid, as the Co-ordinating TNSP in NSW will seek approval from the AER to set the prescribed TUoS – locational price as intended by clause 6A.23.4(g) of *the Rules*.

3.9 *Transmission Prices and Charges*

Calculation of prices for all prescribed transmission services in NSW is carried out by TransGrid as the Co-ordinating TNSP in NSW. Please refer to TransGrid's pricing methodology for the calculation of prices for EnergyAustralia's transmission network. TransGrid receives EnergyAustralia's transmission models with all assets allocated to the relevant asset classes and a portion of the AARR allocated to give the ASRR for each class. Assets within each asset class have already been allocated a portion of the ASRR for that class in accordance with this pricing methodology.

3.10 *Contract Demand Charge*

EnergyAustralia is able to propose locations on its transmission network where an excess demand charge is to apply. EnergyAustralia nominates to TransGrid the particular location of one of EnergyAustralia's transmission connections points (whether that is a connection point direct to TransGrid or one that connects EnergyAustralia's distribution network to it's transmission network) where excess demand charging is to apply. EnergyAustralia also proposes an agreed maximum demand for this connection point. If EnergyAustralia's maximum demand exceeds the *contract agreed maximum demand* level at any time during the financial year then an Excess Demand Charge applies.

TransGrid determines the rates for the Contract Demand Charge as the co-ordinating TNSP in NSW. Details on the contract maximum demand charge can be found in TransGrid's *transmission pricing methodology*

3.11 *Setting of TUoS Locational Prices between Annual Price Publications*

In the event that EnergyAustralia requires a TUoS locational price at a new connection point or at a connection where the load has changed significantly after prescribed TUoS service locational prices have been determined and published, an interim price, not subject to the side constraints of clause 6A.23.4(f) of *the Rules*, will be determined by TransGrid as the co-ordinating TNSP in NSW. This will be calculated using the prevailing pricing models with demands estimated in a manner consistent with clause 2.2(f) of the *transmission pricing methodology guidelines*.

A price subject to the side constraints of clause 6A.23.4(f) of *the Rules* will be determined and published at the next annual price determination.

4 Billing Arrangements

4.1 *Billing for prescribed transmission services*

Consistent with the clause 6A.27.1 of *the Rules,* EnergyAustralia will calculate the transmission service charges payable by *Transmission Network Users* connected to the EnergyAustralia transmission network, in accordance with the transmission service prices published under clause 6A.24.2 as calculated by TransGrid. The prices calculated by TransGrid that are relevant to the EnergyAustralia transmission network are published on the EnergyAustralia website.

Where charges are determined for *prescribed transmission services* from metering data, these charges will be based on kW or kWh obtained from the metering data managed by NEMMCO.

EnergyAustralia will issue bills to *Transmission Network Users* for *prescribed transmission services* which satisfy or exceed the minimum information requirements specified in clause 27.2 of *the Rules* on a monthly basis or as agreed between the parties.

Consistent with clause 6A.27.3 of *the Rules,* a *Transmission Network User* must pay charges for *prescribed transmission services* properly charged to it and billed in accordance with the *transmission pricing methodology* of the relevant *Transmission Network Service Provider* by the date specified on the bill. For the avoidance of doubt, EnergyAustralia's transmission connected customers bills are sent to their retailer, rather than to the customer directly.

4.2 *Payments between Transmission Network Service Providers*

Consistent with clause 6A.27.4 of *the Rules,* TransGrid is the *Co-ordinating Network Service Provider* in NSW under 6A.29.1 of *the Rules* and will pay to each other relevant *Transmission Network Service Provider* the revenue which is estimated to be collected during the following year by the first provider as charges for *prescribed transmission services* for the use of transmission systems owned by those other *Transmission Network Service Providers.*

Such payments will be determined by TransGrid as the *Co-ordinating network service provider* for the region.

Financial transfers payable under clause 6A.27.4 of *the Rules* will be paid in equal monthly instalments or as documented in revenue collection agreements negotiated between the parties.

5 Prudential Requirements

5.1 *Prudential Requirements for prescribed transmission services*

Consistent with clause 6A.28.1 of *the Rules,* EnergyAustralia may require a *Transmission Network User* to establish prudential requirements for either or both connection services and transmission use of system services. These prudential requirements may take the form of, but need not be limited to, capital contributions, pre-payments or financial guarantees.

The requirements for such prudential requirements will be negotiated between the parties and specified in the applicable connection agreement.

5.2 *Capital contribution or prepayment for a specific asset*

Consistent with clause 6A.28.2 of *the Rules,* where EnergyAustralia is required to construct or acquire specific assets to provide prescribed connection services or *prescribed TUoS services* to a *Transmission Network User*, EnergyAustralia may require that user to make a capital contribution or prepayment for all or part of the cost of the new assets installed.

In the unlikely event that a capital contribution is required, any contribution made will be taken into account in the determination of prescribed transmission service prices applicable to that user by way of a proportionate reduction in the ORC of the asset(s) used for the allocation of prescribed charges or as negotiated between the parties.

In the event that a prepayment is required any prepayment made will be taken into account in the determination of prescribed transmission service prices applicable to that user in a manner to be negotiated between the parties.

The treatment of such capital contribution or prepayments for the purposes of a revenue determination will in all cases be in accordance with the relevant provisions of *the Rules*.

EnergyAustralia may require a bank guarantee from a transmission customer, to cover the financial year of a transmission investment made by EnergyAustralia for the customer. Bank guarantees will only be relevant in cases where such investments relate to the construction of prescribed transmission assets. Such guarantees will be made in agreement with the customer and hold funds as security for EnergyAustralia in the event that the customer does not provide a satisfactory income stream through payment for TUoS charges over an agreed period of time.

6 Prudent Discounts

EnergyAustralia is required to provide information to TransGrid in relation to prudent discounts relating to EnergyAustralia's transmission customers. TransGrid adjusts, in accordance with rule 6A.26.1(d)-(g), the non-locational component of the ASRR for *prescribed TUoS services* for the amount of any anticipated under-recovery arising from prudent discounts applied. Refer to TransGrid's *transmission pricing methodology* with respect to the calculation of the adjustments and then application of those adjustments under 6A.26.1(d)-(g), as TransGrid is the *Co-ordinating TNSP* for NSW. The calculation of the discount amount is carried out as the difference between the revenue earned with the discounted prices compared to the revenues earned if the maximum allowed prices had been applied, consistent with the *Rules*[7]. This amount is provided by EnergyAustralia to TransGrid as part of the annual pricing

[7] Rules, clause 6A.26.1(d)

process. EnergyAustralia has a prudent discount arrangement with one transmission customer, details of which are attached as a separate confidential document as part of this *pricing methodology*.

7 Monitoring and Compliance

As a regulated business EnergyAustralia is required to maintain extensive compliance monitoring and reporting systems to ensure compliance with its Transmission and Distribution Licence, Revenue Determination, the *National Electricity Rules* together with other legislative obligations.

In order to monitor and maintain records of its compliance with its approved *transmission pricing methodology*, the pricing principles for *prescribed transmission services*, and part J of *the Rules* EnergyAustralia proposes to:

- Maintain the specific obligations arising from part J of *the Rules* in its compliance management system;
- Maintain electronic records of the annual calculation of prescribed transmission prices and supporting information; and
- Periodically subject its transmission pricing models and processes to functional audit by suitably qualified persons.

8 Additional information requirements

EnergyAustralia does not consider transitional arrangements necessary as a result of the implementation of this proposed *transmission pricing methodology*. EnergyAustralia does not have any relevant derogations in accordance with chapter 9 of *the Rules*, nor are there any applicable transitional arrangements arising from chapter 11 of *the Rules* relevant to this proposed *transmission pricing methodology*.

9 Confidential Elements of Pricing Methodology

EnergyAustralia has provided details of a prudent discount to one of its transmission customers, as an attachment to this pricing methodology. EnergyAustralia requests that this attachment be kept confidential by the AER, as this information is of a commercially sensitive nature to the customer. The remainder of this *pricing methodology* is not considered confidential by EnergyAustralia.

Appendix A: Details of Cost Allocation Process

A detailed cost allocation process is used to assign the optimised replacement cost (ORC) of all prescribed service assets to either common service (assets that benefit all transmission customers), network branches (transmission lines or transformers) and *prescribed entry* or *prescribed exit services* in a manner consistent with Section 2.4 of the transmission *pricing methodology guidelines*.

The cost allocation process is summarised as follows:

Step 1: Initial Asset Cost Allocation

Assets and their ORCs are assigned to one of the following primary asset categories:

- transmission lines;
- transformers;
- circuit breakers;
- common service assets (communications, reactive support, office buildings etc.); and
- substation local assets (ancillary equipment, civil work, and establishment).
- The following plant items are not separately identified in ORC values and are incorporated into the ORC of the associated primary items above:
- Bus work;
- Secondary systems including protection and instrument transformers.

Step 2: Allocation to Classes of Service

Assets are allocated to the classes of prescribed service in accordance with the provisions of Section 2.4 of the *transmission pricing methodology guidelines*. In the case of circuit breakers, each circuit breaker has its replacement cost divided evenly between the branches to which it is *directly attributable*. Any circuit breaker that is not *directly attributable* to any branch together with substation local costs identified in step 1 become subject to the priority ordering process.

In the case of a connection asset attributable to multiple network users, such as a transformer, serving multiple transmission customers at a connection point (which may provide *prescribed entry* and/or *prescribed exit services)* the cost of the shared connection asset will be allocated between the network users in accordance with a demand related allocation or as negotiated between the connected parties.

Step 3: Priority Ordering

In the case of those costs which would be attributable to more than one category of *prescribed transmission services*, specifically the substation local assets identified in Step 1 and those circuit breakers identified as substation local costs in Step 2, costs will be allocated in accordance with the provisions of clause 6A.23.2(d) of *the Rules* having regard to the stand alone costs associated with the provision of *prescribed TUoS services* and *prescribed common transmission services* with the remainder being allocated to *prescribed entry and prescribed exit services.* The implementation of the priority ordering process is detailed below.

Priority Ordering Methodology

Rules Requirement

Clause 6A.23.2(d) of *the Rules* requires that:

> Where, as a result of the application of the *attributable cost share*, a portion of the *AARR* would be attributable to more than one category of *prescribed transmission services,* that *attributable cost share* is to be adjusted and applied such that any costs of a *transmission system* asset that would

otherwise be attributed to the provision of more than one category of *prescribed transmission services*, is allocated as follows:

1. to the provision of *prescribed TUoS services*, but only to the extent of the *stand-alone amount* for that *category of prescribed transmission services*;
2. if any portion of the costs of a *transmission system* asset is not allocated to *prescribed TUoS services*, under subparagraph (1), that portion is to be allocated to *prescribed common transmission services*, but only to the extent of the *stand-alone amount* for that *category of prescribed transmission services*;
3. if any portion of the costs of a *transmission system* asset is not attributed to *prescribed transmission services* under subparagraphs (1) and (2), that portion is to be attributed to *prescribed entry services* and *prescribed exit services*.

Stand-alone amount is defined as:

> For a *category of prescribed transmission services*, the costs of a *transmission system* asset that would have been incurred had that *transmission system* asset been developed, exclusively to provide that *category of prescribed transmission services*.

AEMC Rule determination

In its rule determination the AEMC provided the following guidance on the application of the priority ordering approach for the allocation of costs which can be attributed to more than one type of service[8]:

> "The Commission has maintained a priority ordering approach for the allocation of expenses or costs which can be attributed to more than one type of service. The cascading principle adopted by the Commission is based on the premise that users are seen to be the 'cause' of transmission investment. Therefore, costs should be first allocated to prescribed transmission use of system services on a stand-alone basis and then to *prescribed common transmission services*. Where a service/cost cannot justifiably be attributed to TUoS or common services it should be allocated to entry and exit services."

In developing this methodology, EnergyAustralia has had regard for the following example in the rule determination[9]:

Consider a substation costing $30 million that was developed:

- partly in order to provide *Prescribed TUoS services*;
- partly in order to provide *Prescribed common transmission services*; and
- partly in order to provide *prescribed exit services*.

Then assume that had the substation been developed solely to provide *prescribed TUoS services*, it could have been much smaller and would have cost only $10 million. Had the substation been developed solely in order to provide *prescribed common transmission services*, it would have cost $5 million. Finally, had the substation been developed solely in order to provide *prescribed exit services*, it would have cost $20 million.

The application of the principle would then lead to the $30 million cost of the substation being attributed to Prescribed Transmission Service categories as follows:

- $10m to the *prescribed TUoS services* ASRR;
- $5m to the *prescribed common services* ASRR; and

[8] Rule Determination for National Electricity Amendment (Pricing of *Prescribed Transmission Services*) Rule 2006, p5
[9] Ibid p37

- the remaining $15 million to the prescribed exit service ASRR.

Objective and General Approach

The proposed allocation methodology relies on the assumption that substation infrastructure and establishment costs are proportionate to the number of high voltage circuit breakers in the substation.

Based on this assumption, the appropriate allocator for substation infrastructure and establishment costs for a stand-alone arrangement is the ratio of the number of high voltage circuit breakers in the stand-alone arrangement to the number of high voltage circuit breakers in the whole substation.

Step 1: Branch Identification

Identify the branches, being the lines, transformers, major reactive devices and exits/entries in the substation which provide prescribed TUoS, *prescribed common transmission services* and exit or entry services, in the substation.

Step 2: Allocation of Circuit Breakers to Branches

For each high voltage circuit breaker in the substation identify the branches directly connected to it. Any circuit breaker that does not directly connect to a branch is excluded from allocation and all costs associated with it are added to the substation infrastructure and establishment cost.

Count the total number of circuit breakers directly connected to branches.

As a general rule, Distribution Network Service Providers (DNSPs) are classified as a prescribed exit service while Generators are classified as a prescribed entry service. Negotiated services are not part of the regulated asset base and fall outside the priority ordering process detailed in clause 6A.23.2(d) of *the Rules*.

Step 3.1: Stand-alone arrangements for Prescribed TUoS

With reference to the number of lines providing prescribed TUoS services determine the number of circuit breakers required to provide TUoS services of an equivalent standard on a stand-alone basis21. The stand-alone configuration is the simplest substation configuration (in the absence of development) had it been developed to provide a prescribed TUoS service. This may be done by way of a look up of typical stand-alone configurations.

Step 3.2: Stand-alone arrangements for Prescribed common transmission services

With reference to the number of lines providing *prescribed TUoS services* and the devices providing *prescribed common service* determine the number of circuit breakers required to provide *prescribed common transmission services* of an equivalent standard on a stand-alone basis. The stand-alone configuration is the simplest substation configuration (in the absence of development) had it been developed to provide a *prescribed common service*. This may be done by way of a look up of typical stand-alone configurations.

Step 4: Allocation of substation infrastructure and establishment costs

Step 4.1. Allocation of Prescribed TUoS

Allocate a portion of substation infrastructure and establishment costs to prescribed TUoS according to the ratio of the high voltage circuit breakers identified in step 3.1 to the total number of high voltage circuit breakers connected to branches in the substation identified in step 2.

Step 4.2 Calculate the Unallocated Substation Infrastructure Costs after TUoS Allocation

Calculate the Unallocated substation infrastructure cost by subtracting the amount calculated in step 4.1 from the total substation infrastructure amount.

Step 4.3 Allocation of Prescribed Common Service

Allocate a portion of the substation infrastructure and establishment costs to *prescribed common service* based on to the ratio of the high voltage circuit breakers providing *prescribed common transmission services* identified in step 3.2 to the total number of high voltage circuit breakers connected to branches in the substation. If the common service portion of substation infrastructure is greater than the Unallocated costs, then the Unallocated portion only is attributed to *prescribed common service*. In this instance, nothing will be attributed to *prescribed entry and prescribed exit services.*

Step 4.4 Calculate the Unallocated Substation Infrastructure Costs after Common Service Allocation

Calculate the Unallocated substation infrastructure cost by subtracting the amount calculated in step 4.3 from the amount calculated in step 4.2.

Step 4.5 Allocation of Prescribed Entry and Exit Service

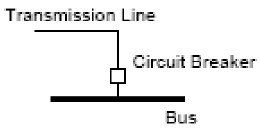
Allocate the remaining substation infrastructure and establishment costs (calculated in step 4.4) to each branch providing prescribed exit or entry services based on the ratio of the high voltage circuit breakers providing the entry or exit service to the branch to the total number of high voltage circuit breakers providing entry or exit services or in accordance with the TNSP's cost allocation methodology as appropriate.

Notes

- Costs are only allocated in step 4 until fully allocated.
- Consistent with clause 6A.23(d)(3) of *the Rules* it is possible that no costs will be attributed to entry and exit services.
- New and existing negotiated service assets are excluded from the analysis as any incremental establishment costs associated with them are taken to be included in the negotiated services charges on a causation basis.
- The assessment of standalone arrangements only needs to be conducted once per substation except where changes to the configuration of the substation occur.

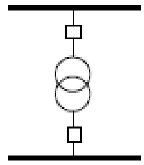
Definition - Branches

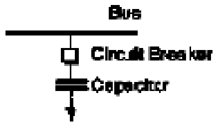
As illustrated by the diagrams below a "Branch" is a collection of assets (e.g. lines, circuit breakers, capacitors, buses and transformers) that provide a transmission service.



Branch with Transmission Line, Bus and Circuit Breaker

Branch with Transformer, Circuit Breaker and two Busses

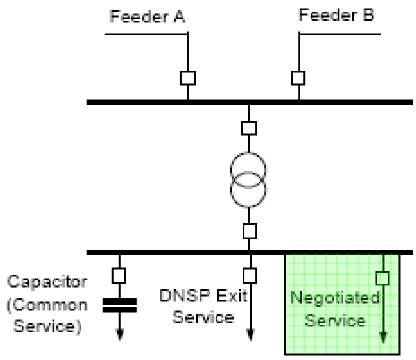




Branch with Capacitor, Circuit Breaker and Bus

Worked Example 1: Substation Costs Priority Ordering

Consider the substation below with an ORC value of $12M. However $3m is for the existing negotiated service, which does not form part of the regulated asset base and is not governed by 6A.23.2(d). Therefore, the negotiated service does not exist for the purposes of priority ordering, and the total infrastructure cost is $9M for allocation purposes.

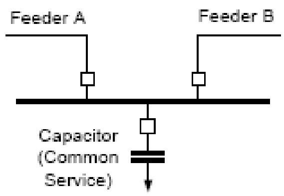


Step 1: The branches are Feeder A, Feeder B, DNSP Exit, Tie Transformer and Capacitor, the negotiated service branch is not considered as discussed above.

Step 2: The total number of circuit breakers directly connected to branches is 6.

Step 3.1: The stand-alone arrangement for the provision of *prescribed TUoS services* to an equivalent standard is shown below and consists of 2 circuit breakers.

Step 3.2: The stand-alone arrangement for the provision of *prescribed common transmission services* to an equivalent standard is shown below and consists of 3 circuit breakers.



Step 4:

Total infrastructure cost is $9M, excluding the negotiated service as discussed.

Costs are allocated to prescribed TUoS in the ratio of the circuit breakers in the stand-alone arrangement to the total circuit breakers.

Infrastructure Cost Allocated to TUoS = (2/6) x $9m = $3m

Unallocated = $9m - $3m = $6m

Costs are allocated to *prescribed common service* in the ratio of the circuit breakers in the stand-alone arrangement to the total circuit breakers.

Infrastructure Cost allocated to Common Service = (3/6) x $9m = $4.5m

Unallocated = $6m - $4.5m = $1.5m

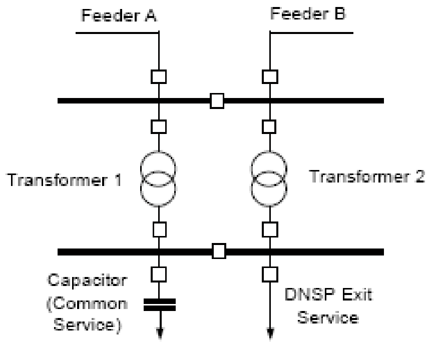
Remainder of Unallocated (calculated above) to be allocated to *prescribed entry and prescribed exit services*.

Infrastructure Cost allocated to Exit = $1.5m

Asset Class	Breakers	Allocation	Unallocated
Substation Infrastructure Costs		$9M	$9M
Total Breakers	6		
TUoS Stand Alone Breakers	2		
1. Share to TUoS	=2/6	= 2/6 x $9M = $3M	$6M
Common Service Stand Alone Breakers	3		
2. Share to Common Service	=3/6	= 3/6 x $9M = $4.5M	$1.5M
3. Share to Entry and Exit Services		= $1.5M	

Worked Example 2: Substation Cost Priority Ordering

Consider the substation below:



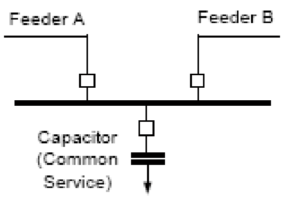
Step 1: The branches are Feeder A, Feeder B, DNSP Exit, Transformer 1, Transformer 2 and Capacitor.

Step 2: The total number of circuit breakers directly connected to branches is 8. The bus section breakers are not directly connected to any of the branches and are therefore ignored for the purposes of priority ordering.

Step 3.1: The stand-alone arrangement for the provision of *prescribed TUoS services* to an equivalent standard is shown below and consists of 2 circuit breakers. Note the bus section breaker is ignored since it is not connected to any of the branches

Step 3.2: The stand-alone arrangement for the provision of *prescribed common transmission*

services to an equivalent standard is shown below and consists of 3 circuit breakers.



Step 4:

Assume the total infrastructure cost is $9M.

Costs are allocated to prescribed TUoS in the ratio of the circuit breakers in the stand-alone arrangement to the total circuit breakers.

Infrastructure Cost Allocated to TUoS = (2/8) x $9M = $2.25M

Unallocated = $9M - $2.25M = $6.75M

Costs are allocated to *prescribed common service* in the ratio of the circuit breakers in the stand-alone arrangement to the total circuit breakers.

Infrastructure Cost allocated to Common Service = (3/8) x $9M = $3.375M

Unallocated = $6.75M - $3.375M = $3.375M

Remainder of Unallocated (calculated above) to be allocated to *prescribed entry and prescribed exit services.*

Infrastructure Cost allocated to Exit = $3.375M

Asset Class	Breakers	Allocation	Unallocated
Substation Infrastructure Costs		$9M	$9M
Total Breakers	8		
TUoS Stand Alone Breakers	2		
1. Share to TUoS	=2/8	= 2/8 x $9M = $2.25M	$6.75M
Common Service Stand Alone Breakers	3		
2. Share to Common Service	=3/8	= 3/8 x $9M = $3.375M	$3.375M
3. Share to Entry and Exit Services		= $3.375M	

Appendix U: Submissions

The AER received submission on the NSW DNSPs' regulatory proposals from the following organisations:

EnergyAustralia

Energy Market Reform Forum (EMRF)

Energy Users Association of Australia (EUAA)

Public Interest Advocacy Centre (PIAC)

Total Environment Centre (TEC)

The AER also received submissions on alternative control services, in particular public lighting, from the following organisations:

Bankstown City Council

Baulkham Hills City Council

Blacktown Council

Camden Council

Campbelltown Council

EnergyAustralia

Fairfield City Council

Kiama Municipal Council

Liverpool City Council

Parramatta City Council

Riverina Eastern Regional Organisation of Councils (REROC)

Southern Sydney Regional Organisation of Councils (SSROC)

Western Sydney Regional Organisation of Councils (WSROC)

The AER also received submissions from several NSW Councils which raised very similar issues and are collectively referred to as 'the similar submissions from several NSW Councils'. The NSW Councils which made these submissions are set out below:

Ashfield Council

Burwood Council

City of Botany Bay

City of Canada Bay Council

City of Canterbury Council

City of Lake Macquarie

City of Newcastle

City of Sydney

Gosford City Council

Hunters Hill Council

Hurstville City Council

Kogarah Council

Ku–rin–gai Council

Lane Cove Council

Leichhardt Council

Marrickville Council

Mosman Municipal Council

North Sydney Council

Port Stephens Council

Randwick City Council

Rockdale City Council

Strathfield Council

Sutherland Shire Council

Waringah Council

Waverley Council