Country Energy's Electricity Network Revised *Regulatory Proposal* 2009-2014

16 January 2009

countryenergy

We live here too.

Contents

Introduction

1 Introduction

1.1 Country Energy's revised *regulatory proposal*

Country Energy is a *regulated network service provider* (*RNSP*), operating an electricity distribution network that extends across an operating area covering 95 per cent of New South Wales' (NSW) land mass, and into parts of Queensland, Victoria and the Australian Capital Territory. Within NSW, Country Energy is licensed to operate its network under the *Electricity Supply Act* 1995 (NSW).

The *Australian Energy Regulator* (*AER*) assumed responsibility for the economic regulation of electricity distribution networks on 1 January 2008 after the enactment of the *National Electricity Law* (the *Law*) and *National Electricity Rules* (the *Rules*). The *AER* is now the jurisdictional regulator with responsibility for making a *distribution determination* as defined under the *Law* and *Rules*.

On 2 June 2008 Country Energy submitted a *regulatory proposal* to the *AER* for the *regulatory control period* from 1 July 2009 to 30 June 2014 in accordance with the *Rules*. Country Energy's *regulatory proposal* has since been the subject of compliance confirmation, public consultation and detailed review by the *AER* and its consultants. On 28 November 2008, the *AER* published a Draft decision on the *distribution determination* for Country Energy ("Draft Decision").

Country Energy is subject to the provisions of transitional Chapter 6 contained in Chapter 11 of the *Rules* (the transitional *Rules*), rather than the general Chapter 6. This revised *regulatory proposal* is therefore submitted by Country Energy in accordance with the transitional *Rules*. Relevant aspects of the transitional *Rules* are described in subsequent sections of this revised *regulatory proposal*.

Country Energy's revised *regulatory proposal* presents an annual revenue requirement that increases from $1,006 million (nominal) in 2009-10 to $1,511 million (nominal) in 2013-14. Country Energy's revised forecast operating expenditure for the next *regulatory control period* is $2,267 million ($2008-09). Country Energy's revised forecast capital expenditure for the next *regulatory control period* is $4,047 million ($2008-09). Country Energy's revised opening regulatory asset base (RAB) at 1 July 2009 is $4,262 million.

Country Energy is subject to several incentive schemes under the *AER*'s Draft decision, notably the service target performance incentive scheme (STPIS), the efficiency benefit sharing scheme (EBSS) and the demand management incentive schemes. Country Energy supports most of the *AER*'s Draft decision on these schemes, with some minor suggestions for refinement or improvement.

In addition, the *AER* considered Country Energy's negotiating framework for negotiable components of direct control services and accepted the proposed framework as compliant with the requirements of the transitional *Rules*.

Country Energy believes that this revised *regulatory proposal* and the accompanying operating and capital expenditure forecasts reasonably reflect the efficient costs of a prudent operator in the position of Country Energy.

Country Energy's revised *regulatory proposal* comprises:

- This revised *regulatory proposal* document

- Reference documents contained in the appendices
- Completed post tax revenue model and roll forward model.

This revised *regulatory proposal* details Country Energy's intentions for the next *regulatory control period,* aimed at delivering a reliable, affordable and sustainable electricity network service.

Country Energy welcomes feedback in response to this revised *regulatory proposal*, especially where this may lead to improvements or enhancements to the quality and effectiveness of our services to customers.

The remainder of this chapter is structured as follows:

- Section 1.2 describes the approach taken by Country Energy in this revised *regulatory proposal*, and
- Section 1.3 explains the remaining structure of this revised *regulatory proposal*.

Italicised words and phrases in this *regulatory proposal* have the meaning given to them in the *Law* or *Rules*, unless otherwise specified.

Business details

Country Energy
ABN: 37 428 185 226
PO Box 718, Queanbeyan NSW 2620

Contact details

Inquiries about this revised *regulatory proposal* can be directed to:

Jason Cooke, Group Manager Regulatory Strategy
PO Box 718, Queanbeyan NSW 2620
Jason.Cooke@countryenergy.com.au

Natalie Lindsay, General Manager Regulatory Affairs
PO Box 718, Queanbeyan NSW 2620
Natalie.Lindsay@countryenergy.com.au

Bill Frewen, Group General Manager External Relations
PO Box 718, Queanbeyan NSW 2620
Bill.Frewen@countryenergy.com.au

1.2 Country Energy's approach to this revised *regulatory proposal*

Country Energy's revised *regulatory proposal* is prepared and lodged in accordance with clause 6.10.3 of the transitional *Rules*.

Country Energy has carefully reviewed all matters addressed by the *AER* in its Draft decision, particularly where adjustments have been made to Country Energy's original *regulatory proposal* dated 2 June 2008. Where Country Energy has not implemented a particular aspect of the *AER*'s Draft Decision, this revised *regulatory proposal* provides reasoning and supporting information and expert reports.

Country Energy's revised *regulatory proposal* incorporates the *regulatory proposal* dated 2 June 2008 and contains references to both it and the *AER*'s Draft Decision. This revised *regulatory proposal* should therefore be read in conjunction with those documents. To the extent of any inconsistency between Country Energy's *regulatory proposal* dated 2 June 2008 and this document, the latter will prevail.

1.3 Structure of this revised *regulatory proposal*

The remainder of this revised *regulatory proposal* addresses each of the decisions made by the *AER* in its Draft Decision and is structured as follows:

- Chapter 2 discusses network services, their classification and control mechanism
- Chapter 3 provides Country Energy's revised demand forecasts that underpin the expenditure programs and post tax revenue model
- Chapter 4 details Country Energy's revised operating expenditure forecast
- Chapter 5 details Country Energy's revised capital expenditure forecast
- Chapter 6 describes the revised regulatory and tax depreciation allowances
- Chapter 7 presents the regulated asset base for the next *regulatory control period*
- Chapter 8 details the weighted cost of capital and cost of tax for the next *regulatory control period*
- Chapter 9 discusses the proposed application of the efficiency benefit sharing scheme, demand management incentives, pass through arrangements and transitional issues
- Chapter 10 provides an overview of the revenue outcomes resulting from this revised *regulatory proposal*
- Chapter 11 describes Country Energy's proposal for alternative control services for the next *regulatory control period*
- Chapter 12 lists a glossary of terms, and
- Chapter 13 presents a list of appendices attached to this revised *regulatory proposal*.

Network and services

2 Network and Services

2.1 Overview

Country Energy's *regulatory proposal*, dated June 2008, did not propose to vary the deemed classification of services as set out in clause 6.2.3B of the transitional *Rules*.

Country Energy's *regulatory proposal* also submitted that there were no negotiable components of direct control services and therefore did not initially provide a negotiating framework. However, in response to the *AER*'s request, Country Energy subsequently lodged a proposed negotiating framework.

Country Energy's *regulatory proposal* calculated a revenue requirement and X factors for standard control services for the next *regulatory control period* under a weighted average price cap (WAPC) control mechanism. Country Energy also proposed a schedule of charges for miscellaneous and monopoly services for the first year of the next *regulatory control period* that were to be escalated each year.

In its Draft Decision, the *AER*:

a) applied the deemed classification of services as provided for in the transitional *Rules*

b) accepted Country Energy's negotiating framework to apply for the next *regulatory control period*

c) applied a WAPC formula to Country Energy's standard control services for the next *regulatory control period*

d) retained the same categories and definitions used in the current IPART determination for emergency recoverable works, miscellaneous services and monopoly services

e) set out a schedule of charges for emergency recoverable works and miscellaneous and monopoly services for the next *regulatory control period*, reflecting actual and estimated CPI movements over both the current and next *regulatory control period*s.

Country Energy has implemented the majority of the *AER*'s Draft Decision described above with the exception of the schedule of charges for emergency recoverable works, miscellaneous services and monopoly services.

The remainder of this chapter details Country Energy's proposed charges for emergency recoverable works, miscellaneous services and monopoly services.

2.2 Charges for Emergency Recoverable Works, Miscellaneous Services and Monopoly Services

Country Energy holds the view that future charges for recoverable works, miscellaneous services and monopoly services need to be analysed to ensure that they are at cost reflective levels. This will signal to accredited service providers and customers the true cost of delivering these services. While Country Energy acknowledges that the time constraints involved in this determination process make a full review impractical, Country Energy believes that the *AER* should reconsider the methodology applied to inflate the current *regulatory control period* charges.

The original charges were set in the 1999 IPART Determination, and since that time have only been subject to inflation by CPI once every five years. The provision of these services mainly involves labour intensive activities. As acknowledged by the *AER*, labour costs have increased significantly in real terms since the original charges were set. Country Energy understands that because the revenue from these services forms part of the weighted average price cap for standard control services, any shortfall in cost reflective revenue will be gained from general distribution use of system charges. However, to maintain an approach in setting these charges similar to that adopted for previous determinations, will only further disconnect these charges from cost reflective levels. This is likely to result in larger price shocks for accredited service providers and customers in 2014 when they are comprehensively reviewed during the next *regulatory control period*.

Country Energy therefore maintains the view that the *AER* should increase the current charges for these services using the CPI plus a real Electricity, Gas and Water (EGW) wage escalator encompassing both the current and future *regulatory control period*s.

.

Demand Forecasts

3 Demand Forecast

3.1 Overview

Country Energy's *regulatory proposal* described the methodology for forecasting growth in consumption, customer numbers and peak demand for the next *regulatory control period*.

In its Draft Decision, the *AER*:

a) Accepted that Country Energy's maximum demand forecast methodology and forecasts provide a realistic expectation of the demand forecast required to achieve the capital expenditure and operating expenditure objectives listed within Country Energy's *regulatory proposal*

b) Did not accept the energy and customer number forecasts provided within Country Energy's *regulatory proposal*, under clause 6.12.1(10) of the transitional *Rules*, as it considers that the forecasts are outdated and therefore are inappropriate inputs into the *AER*'s post tax revenue model (PTRM), and

c) Considered Country Energy's consumption and customer number forecast methodologies reasonable, but 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. The *AER* requested 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 PTRM, by 20 February 2009.

Country Energy agrees with the AER that the most recent energy sales and customer numbers data should be used to ensure its forecasts are as current as possible, and as such has implemented the majority of the AER's Draft Decision listed above in relation to its demand forecasts. However, due to recent events, Country Energy has taken further steps to ensure the forecasts in its regulatory proposal are updated with the most recent and accurate data available. This approach is in line with both the AER decision and the objectives of the Law and ensures that the most relevant data available is used in making a determination.

The remainder of this chapter is structured as follows:

- Section 3.2 provides information on the impact of recent economic events on Country Energy's growth forecasts
- Section 3.3 provides information on the impact of the implementation of the carbon pollution reduction scheme (CPRS) in July 2010 announced by the federal government on 15 December 2008
- Section 3.4 presents Country Energy's revised forecasts for customer numbers, consumption and peak demand, and
- Section 3.5 summarises Country Energy's overall forecasts for the next *regulatory control period*.

Country Energy has attached the updated report on demand forecasts to this revised proposal as Appendix A.

3.2 Impact of Recent Economic Events on Country Energy Growth Forecasts

Country Energy's June 2008 *regulatory proposal* contained demand forecasts prepared by the National Institute of Economic and Industry Research (NIEIR) and informed by economic assumptions up to November 2007. Given recent downturns in economic and financial environments around the world, Country Energy engaged NIEIR to update these demand forecasts with the most recent and up to date information available.

The World economic outlook

NIEIR is estimating that the GDP of many major economies of the world is expected to fall substantially between 2009 and 2010. Section 2 of appendix A contains details of the estimated impact of recent economic events on the world economies.

The NIEIR report details a dampening of growth due to recent economic events, but shows a reasonable worldwide recovery is estimated to occur towards the latter half of the next *regulatory control period*. Figure 1 below illustrates that world GDP is estimated to fall to 0.8 per cent in 2010 from a high of 5 per cent in 2006, with an expected recovery to 4.3 per cent by 2014. The average annual world GDP calculated from this data is 2.8 per cent over the next *regulatory control period* compared with an average annual world GDP of 4.5 per cent in the current *regulatory control period*. It should be noted that the world is generally said to be in recession when global GDP falls below an average of 3 per cent, with a number of larger international economies having already entered a period of recession.

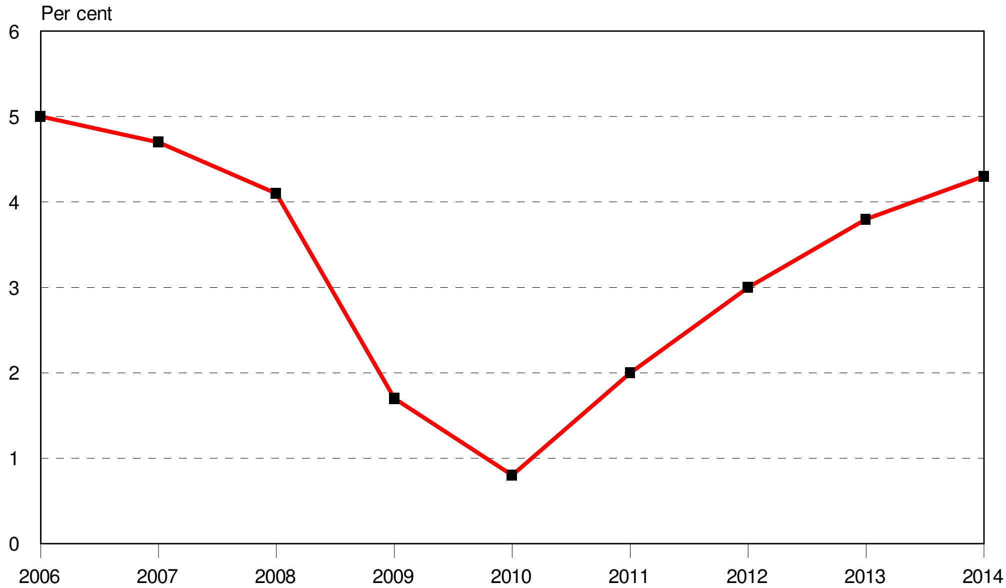

Figure 1 – Estimated world GDP between 2006 and 2014

The Australian and NSW economic outlook

Australia's GDP is now estimated to fall to between 0.6 per cent and 1.8 per cent between 2009 and 2011. NSW GDP is expected to fall below zero with GDP in the range of -1.3 per cent to 0.5 per cent over the same period. Refer to table 3.1 in appendix A for further details.

Australia and NSW are also estimated to stage a reasonable recovery consistent with the world economy during the latter part of the next *regulatory control period.* The resulting average annual Australian GDP is 2.8 per cent (down from 3.0 per cent in the *regulatory proposal*) and an average annual NSW GDP of 2.0 per cent (down from 2.7 per cent in the *regulatory proposal*).

The Country Energy economic outlook

The economic outlook for the Country Energy region shows growth being below the state average. The Country Energy region's economy is forecast to grow by an average 1.2 per cent per annum (down from 1.5 per cent in the *regulatory proposal*) through the next *regulatory control period*. However, the Northern region, which encompasses the north coastal strip, is forecast to grow at 2 per cent per annum, slightly above the NSW state average. These growth rates are illustrated in Table 1 below.

Average Annual Gross Regional Product	Central West Region	Southern Region	Northern Region	Far West Region	Country Energy Total	New South Wales
2009 to 2014	-0.14%	0.51%	2.06%	0.68%	1.17%	2.01%

Table 1– Average Annual Gross Regional Product (GRP) for the next *regulatory control period*.

Population growth for Country Energy's region is forecast to grow by 0.5 per cent compared to the NSW state average of 0.8 per cent. Country Energy's population growth is strongest in the northern coastal region at an average 0.7 per cent, compared to regions located west of the ranges which show an average of only 0.1 per cent. Dwellings in the Country Energy region are projected to grow by an average rate of 1.0 per cent per annum compared to the state average of 1.2 per cent.

3.3 Impact of the Implementation of the Carbon Pollution Reduction Scheme

On 15 December 2008, the Federal Government released a White Paper (the paper) on the Carbon Pollution Reduction Scheme (CPRS). The paper confirmed emissions trading scheme is to be introduced by 2010-11 and outlines the final design and reduction targets of the CPRS. Further information on NIEIR's assessment of the paper and its implications on the demand forecasts are provided in section 5 of Appendix A.

3.4 Country Energy's Revised Growth Forecasts

Energy consumption forecast

Country Energy has continued to adopt the base case growth rates in NIEIR's revised demand forecast report, consistent with the scenario approved by the *AER* in its draft decision. The base case growth rates adopted in this revised *regulatory proposal* are compared to those in the June 2008 *regulatory proposal* forecasts in Table 2 below.

	Previously Submitted Forecast – NIEIR Nov 2007		Revised Forecast – NIEIR Dec 2008	
Energy growth by customer category (% pa) Base Scenario	5yr Forecast 2009-2014 Average	10yr Forecast 2008-2018 Average	5yr Forecast 2009-2014 Average	10yr Forecast 2008-2018 Average
Residential	1.36%	1.30%	0.96%	1.25%
Business	1.70%	1.63%	0.07%	0.54%
Public Lighting	2.25%	2.34%	2.28%	2.38%
Average Base Energy Growth	1.56%	1.49%	0.45%	0.85%

Table 2 - Forecast electricity consumption - Broad based customer categories

Energy consumption is expected to grow at a much more subdued rate as customers curtail their usage and purchasing of energy consuming appliances in the early stages of the next *regulatory control period* due to slowing economic growth and the introduction of the CPRS. These influences have resulted in a reduction in the average energy growth rate to 0.45 per cent for the Country Energy region over the next *regulatory control period*.

Customer number forecast

The economic downturn will also have a constraining effect on the growth in new customer connections, predominantly in the business area as tightened consumer spending in the first half of the next *regulatory control period* curtails business expansion. New business connections growth is expected to slow as operators show a reluctance to start up in uncertain financial times.

Residential customer connection growth will reduce slightly in the early stages but is expected to recover reasonably well in the latter part of the next *regulatory control period*.

Public lighting connection growth is fairly static and is expected to remain unchanged from previous forecasts.

Forecasts of new connections by customer category under the base case scenario are provided in Table 3 below. New customers connecting to the Country Energy network ware forecast to grow by 1.29 per cent per annum over the next *regulatory control period*.

	Previously Submitted Forecast – NIEIR Nov 2007		Revised Forecast – NIEIR Dec 2008	
New customer connection growth by customer category (% pa) base Scenario	5yr Forecast 2009-2014 Average	10yr Forecast 2008-2018 Average	5yr Forecast 2009-2014 Average	10yr Forecast 2008-2018 Average
Residential	1.48%	1.47%	1.47%	1.48%
Business	1.30%	1.38%	0.31%	0.59%
Average base energy growth	1.46%	1.45%	1.29%	1.34%

Table 3 - Forecast new customer connections - Broad based customer categories

Peak demand forecast

The economic downturn is estimated to have a slight constraining effect on the growth in peak demand. The reduction in the peak demand growth rate is smaller than the decrease in the consumption growth rate as customers have less control over their ability to curtail demand during times of system peak.

The revised peak demand forecasts have been calculated using the same NIEIR methodology as that approved by the *AER* in its draft decision and detailed in Country Energy's June 2008 *regulatory proposal*. This has resulted in an average annual winter peak demand growth rate of 1.71 per cent over the next *regulatory control period* compared to the previous forecast of 1.8 per cent.

The revised forecast summer peak demand growth remains unchanged, predominantly due to renewed consumer confidence post 2011. Country Energy's still expects that the network will move from being winter peaking to summer peaking in 2011. Country Energy's revised demand forecast is provided in Table 4 below.

Base Scenario	Country Energy Base 50% POE	
Calendar Year	Winter Demand (MW)	Winter Demand Growth (%)
2007	2,324	-0.51%
2008	2,308	-0.73%
2009	2,391	1.78%
2010	2,406	0.61%
2011	2,446	1.64%
2012	2,475	1.19%
2013	2,511	1.48%
2014	2,547	1.41%
2015	2,584	1.48%
2016	2,643	2.25%
2017	2,693	1.90%
2018	2,693	2.52%
2008-2013 Average Annual Growth Rate		**1.71%**
2008-2018 Average Annual Growth Rate		**1.81%**

Base Scenario	Country Energy Base 50% POE	
Financial Year	Summer Demand (MW)	Summer Demand Growth (%)
2008	2,063	-4.47%
2009	2,311	12.02%
2010	2,325	0.60%
2011	2,386	2.60%
2012	2,515	5.39%
2013	2,602	3.49%
2014	2,681	3.01%
2015	2,750	2.58%
2016	2,805	2.02%
2017	2,895	3.20%
2018	2,986	3.13%
2019	3,111	4.19%
2010-2014 Average Annual Growth Rate		**3.01%**
2009-2018 Average Annual Growth Rate		**3.80%**

Table 4 - Forecast winter and summer demand for Country Energy.

Impact of revised peak demand forecast on Capital Expenditure Forecasts

Country Energy's growth capital expenditure has numerous drivers, with the major drivers being peak demand and new customer connections. To assess the likely impact of the revised peak demand forecasts, it is necessary to look separately at the likely impact on the subtransmission system and the distribution system.

The subtransmission system comprises those assets that operate between 132,000 volts and 33,000 volts. Country Energy has over 330 zone substations and over 14,000km of subtransmission lines and has a comprehensive augmentation work program. The program has been developed to ensure that as peak demand grows, new assets are constructed to ensure that the customer demand is met and planning guidelines are complied with. The program is heavily driven by summer peak demand, which is increasing at a significantly higher rate than the winter demand. As the forecast summer demand growth is expected to remain unchanged at 3 per cent and the winter demand has reduced only slightly from 1.8 per cent to 1.71 per cent, it is unlikely that there will be any change to the timing for the subtransmission projects. Therefore, Country Energy believes that the capital expenditure forecast for the subtransmission system should remain unchanged.

The distribution network comprises those assets that operate at voltages below 22,000 volts and are used to connect new subdivisions and customers to the subtransmission network. The work identified under distribution growth capital expenditure provides new 22,000/11,000 cables and transformers to new subdivisions and other assets that are required to connect new customers. To forecast the likely impact on distribution growth capital expenditure it would be necessary to review the timing of all of the planned subdivisions across NSW. This is obviously difficult, so the forecast of new customer connections provides a guide to the likely impact. The forecast for new customer connections has reduced from 1.46 per cent to 1.29 per cent. This represents a fairly small reduction in new connections, and when this reduction is spread over hundreds of subdivisions across NSW, it is unlikely to significantly change the timing of new subdivision developments. Country Energy therefore believes that the new forecast is expected to have a minimal impact on distribution growth capital expenditure.

3.5 Summary of Revised Electricity Forecasts

Based on the assumed base case growth scenarios, the projected rates of energy consumption, customer numbers, and peak demand across the network for the next *regulatory control period* are:

- Electricity consumption to grow by 0.45 per cent per annum, down from the 1.56 per cent per annum electricity consumption growth rate previously forecast
- New electricity customer connections to grow by 1.29 per cent per annum, down from the 1.46 per cent per annum new customer connection growth rate previously forecast
- Maximum summer demand across the network to grow by 3.01 per cent per annum, and
- Maximum winter demand across the network to grow by 1.71 per cent per annum.

The forecast for residential and business customers compared to Country Energy's June 2008 *regulatory proposal* are shown in Table 5 below.

	Overall		Residential		Business	
	Previous Forecast	Revised Forecast	Previous Forecast	Revised Forecast	Previous Forecast	Revised Forecast
Energy Consumption (%)	1.56%	0.45%	1.36%	0.96%	1.70%	0.07%
New Customer Connections (%)	1.46%	1.29%	1.48%	1.47%	1.30%	0.31%
Winter Maximum Demand (%)	1.80%	1.71%	Not Applicable		Not Applicable	
Summer Maximum Demand (%)	3.00%	3.01%	Not Applicable		Not Applicable	

Table 5 – Forecast of growth rates by customer category 2009 to 2014

Operating Expenditure

4 Operating Expenditure

4.1 Overview

Chapter 4 of Country Energy's *regulatory proposal*, dated June 2008, described the methodology used to develop operating expenditure forecasts for the next *regulatory control period*. Key inputs and assumptions underpinning the operating expenditure forecast were also detailed.

In its Draft Decision, the *AER*:

a) Considered Country Energy's forecasting methods and procedures to be appropriate

b) Considered Country Energy's maximum demand forecast methodologies and forecasts provide a realistic expectation of the demand forecast required to achieve the operating expenditure objectives

c) Accepted Country Energy's proposal to use 2006-07 as an efficient base year from which to forecast its operating expenditure requirements

d) Did not accept Country Energy's proposed estimate for network maintenance costs of $1,828 million and substituted an estimate of $1,667 million

e) Did not accept Country Energy's proposed cost escalation factors and substituted revised escalators and updated CPI calculations

f) Did not accept Country Energy's proposed self insurance costs of $19.5 million and substituted an amount of $15 million

g) Did not accept Country Energy's proposed debt raising costs of $24.2 million and substituted an amount of $12.6 million

h) Did not accept Country Energy's proposed methodology for calculating an allowance for equity raising costs, nor the classification of these costs as operating expenditure.

Country Energy has implemented the majority of the *AER*'s Draft Decision described above except for the following:

- Network maintenance costs adjustment
- Costs for review of voltage regulation relay settings and distribution transformer tap positions
- Vegetation management asset growth escalation
- Costs relating to the outcomes of a specific legal decision involving Country Energy
- Self insurance costs
- Debt raising costs
- Methodology for calculating equity raising costs (refer to discussion in Chapter 5)
- Certain cost escalators

The remainder of this chapter is structured as follows:

- Section 4.2 presents further information on Country Energy's network maintenance costs that were not allowed by the *AER* in its Draft Decision
- Section 4.3 discusses the updated controllable operating expenditure as a result of transferring an amount for tap changes and relay settings from capital expenditure
- Section 4.4 discusses the rationale for the vegetation management asset growth escalator
- Section 4.5 details forecast costs relating to addressing the outcomes of a specific legal decision made during this current *regulatory control period*
- Section 4.6 details Country Energy's position on self insurance costs
- Section 4.7 presents Country Energy's position on debt raising costs
- Section 4.8 details Country Energy's revised cost escalators used in developing the operating expenditure forecasts, and
- Section 4.9 summarises Country Energy's operating expenditure forecasts for the next *regulatory control period*.

4.2 Network Maintenance Costs

Country Energy notes the AER's concerns regarding the proposed operating expenditure associated with vegetation management, network maintenance and inspections, specifically relating to the cost pass through application to IPART in 2005. In this regard, comment is first made on Country Energy's and the AER's obligations under the Law and Rules. Country Energy then provides further detail on the expenditure incurred during the current regulatory control period and additional information on the prudence and efficiency of our proposals for the next regulatory control period.

The National Electricity Objective

Section 7 of the *Law* states that the national electricity objective is:

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

Section 7 thereby prescribes the prioritisation of reliability, safety and security of supply in regulation of distribution networks. Therefore, it is these fundamental priorities that should underpin any decision or determination made under the *Law* or *Rules*.

Country Energy's decision to defer specific aspects of its inspection, maintenance and vegetation management programs in order to maintain operating expenditure on general inspection, maintenance and vegetation management activities of greater priority over the current *regulatory control period,* are supported by these objectives. Country Energy, as a prudent operator, assessed its requirements under the *Law* and the *Rules*, prioritising its obligations to ensure it upheld the national electricity objective.

Recovery of efficient costs

Section 7A(2) of the *Law* stipulates that a service provider must be provided with the opportunity to recover *at least* the efficient costs incurred in providing:

(a) direct control network services; and

(b) compliance with a regulatory obligation or requirement or making a regulatory payment.

Country Energy optimises its operating expenditure by prioritising its regulatory obligations in accordance with the national electricity objective. Such expenditure is the efficient use of resources allocated to it to provide direct control network services and to comply with its licence conditions and regulatory obligations. Section 7A(2) provides that Country Energy must be provided with the opportunity to recover *at least* the costs incurred in providing services where those services are undertaken efficiently.

Regulation of operating expenditure

The national electricity objective is further reinforced by Rule 6.5.6(a) of the transitional *Rules*. In adopting the building block proposal and, in turn, forecasting total operating expenditure for the next *regulatory control period*, Country Energy must include all operating expenditure required for it to achieve each of the *operating expenditure objectives*, being to:

(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.

Country Energy's forecast operating expenditure is required to meet its obligations with regard to demand, compliance with its licence and regulatory obligations, and ensure that reliability, safety and security of standard control services are maintained.

Rule 6.5.6(c) states that the *AER must* accept Country Energy's forecast operating expenditure where it is satisfied that the proposal reasonably reflects:

(1) the efficient costs of achieving the operating expenditure objectives

(2) the costs that a prudent operator in the circumstances of the relevant Distribution Network Service Provider would require to achieve the operating expenditure objectives

(3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

Country Energy asserts that it is a prudent operator that has applied and does apply its resources to prioritised programs in accordance with managing the safety, reliability and security of the system. This further supports Country Energy's position that this is an efficient use of resources available.

Rule 6.5.6(c) is to be read with Rule 6.5.6(e). Rule 6.5.6(e) contains ten specific provisions that the *AER* must have regard to when accepting a forecast of required operating expenditure. The reference in Rule 6.5.6(e)(5) to the past *regulatory control period* merely indicates what has occurred, but forecast operating expenditure is what must be done to comply in the future with regulatory obligations and requirements. The forward looking nature of forecasting operating expenditure requires the *AER* to consider all of the balance of factors in Rule 6.5.6(e) to meet future obligations.

When deciding if it is satisfied that Country Energy's forecast operating expenditure reasonably reflects the efficient costs of a prudent operator in the circumstances, the *AER* must assess the forecast operating expenditure prospectively. The *AER* must consider the *operating expenditure objectives* and the national electricity objective in reaching a determination with respect to forecast operating expenditure. It is not merely the assessment of one aspect of Rule 6.5.6(e) that must be considered, but each factor in accordance with the overriding national electricity objective.

The AER's Draft Decision

It is apparent from its Draft Decision that the *AER* has not applied the *operating expenditure objectives* and the national electricity objective as governing considerations in assessing whether to accept Country Energy's forecast operating expenditure. Moreover, the *AER* has failed to provide any assessment of the considerations in Rule 6.5.6(e) beyond Rule 6.5.6(e)(5). The transitional *Rules* provide no discretion for the *AER* to exclude factors in the making of its decision, nor is there any weight to be given to one provision over another in Rule 6.5.6(e).

The *AER* is required to have regard to each of the factors in Rule 6.5.6(e), the *operating expenditure objectives* and the national electricity objectives in reaching its determination. The determination process is a forward looking examination and heavy reliance on previous regulatory allowance decisions for operating expenditure significantly undermines the prospective nature of a regulatory determination.

The Draft Decision relies merely on the operating expenditure approved in the current IPART determination. Although retrospective analysis of actual and expected operating expenditure in a preceding *regulatory control period* is provided for under Rule 6.5.6(e)(5), the *AER* has made its Draft Decision in consideration of this single aspect of Rule 6.5.6(e) to the exclusion of the other nine considerations. Neither the *Law* nor the *Rules* provide for such discretion.

Clause 16 of the *Law* states: "The *AER* must, in performing or exercising an *AER* economic regulatory function or power – perform or exercise that function or power in a manner that will or likely to contribute to the achievement of the national electricity objective…" The *AER* is also required to take into account the revenue and pricing principles when exercising its discretion in making parts of a distribution determination relating to direct control network services (Clause 16(2)(a)(i)).

Further, the making of a determination is prospective in its application. The basic principle in transitional Rule 6.5.6(a) of forecasting operational expenditure that Country Energy considers is required in order to achieve the *operating expenditure objectives* in the next *regulatory control period* must not be diluted by reliance on past decisions. Moreover, the assessment of whether Country Energy is efficient and a prudent operator can not be based solely upon operating within a component that constitutes only a part of a previous operational allowance.

In summary, Country Energy submits that:

- it is a prudent operator and is efficient in the management of its operational cost allowances and allocation of resources
- in deferring programs to the next *regulatory control period*, undertook its operations in an efficient manner and redirected its resources to those aspects of operations that were of priority in upholding the safety, security and reliability of the network
- it is a prudent operator that determines the priority of operational expenditure in order to uphold the operating expenditure objectives. It is the finite pool of funds allocated to Country Energy for expenditure on operations that should be considered by the *AER*, rather than a single component of these funds that have been diverted for the benefit of the network
- the forecast operating expenditure proposed by Country Energy is an accurate reflection of the expenditure required to achieve each of the operating expenditure objectives. Significantly, a substantial portion of forecast expenditure is to ensure Country Energy's compliance with (2) and (3) of Rule 6.5.6(a).

Further detail of the allocation of this expenditure in the current *regulatory control period* is set out elsewhere in this section.

Country Energy therefore submits that where the *AER* assesses its actual and expected operating expenditure during a preceding *regulatory control period* under transitional Rule 6.5.6(e)(5), it must consider how a prudent operator allocated its costs efficiently in totality, rather than on the basis of an individual component. All remaining factors of transitional Rule 6.5.6(e) must be considered in a prospective context together with the overarching principles of the transitional *Rules* and the *Law,* as detailed above, in order for the *AER* to discharge its regulatory obligation.

It the *AER* accepts that Country Energy allocated its pool of funds as a prudent operator would, then it follows that Country Energy should not be denied the ability to recover forecast operating expenditure to meet its future asset management requirements and compliance with licence and regulatory obligations. Likewise, if Country Energy's Network Asset Management Plan is appropriate in accordance with that of a prudent operator, then Country Energy should not be denied recovery of its efficient costs. The retrospective analysis of the allocation of funds as the basis for excluding forecast operating expenditure fails to adequately assess all factors in 6.5.6(e) and consider costs prospectively.

By denying Country Energy the operating expenditure required to comply with its regulatory obligations, the *AER* is effectively preventing it from undertaking expenditure that a prudent operator would engage in to uphold the *operating expenditure objectives*. Further, by denying recovery of operating expenses that enable Country Energy to comply with its regulatory requirements disregards the national electricity objective as the principle obligation which a service provider must uphold.

Expenditure in the current regulatory control period

During the current *regulatory control period* Country Energy is undertaking a significant vegetation management program as part of a coordinated approach to effective stewardship of overhead assets. The expenditure associated with undertaking this work aligns with the total amount included by Country Energy in it's submissions to IPART for vegetation management. This includes Country Energy's operating expenditure cost pass-through submission to IPART as a result of the imposition of the *Design, Reliability and Performance Licence Conditions* on Country Energy by the NSW Minister for Energy during the current *regulatory control period*.

As stated in the Wilson Cook report, Country Energy was only formed in 2001 and it is generally agreed that the historical vegetation management spends of the previous distribution businesses were not a good basis to determine the level of expenditure required by the consolidated business to comply with the Industry Safety Steering Committee requirements[1]. Hence, the vegetation management expenditure forecasts included in the total operating forecasts at this time were insufficient. Country Energy notes that this appears to be generally accepted by the *AER* and its consultants.

The new *Design, Reliability and Performance Licence Conditions* were imposed on Country Energy by the Minister for Energy on 1 August 2005 under the auspices of the *Electricity Supply Act* 1995 (NSW). Country Energy submitted a cost pass through application to IPART in December 2005 for the incremental costs relating to compliance with the new licence conditions.

IPART approved an annual operating expenditure pass through allowance of $45 million (2008-09) for the three years 2006-07 to 2008-09. Country Energy has to date spent the annual allowance in each of these years entirely on general vegetation clearing and intends to continue this practice until the end of the current *regulatory control period*. This policy decision was founded on a comprehensive risk assessment, based on AS4360, which was undertaken by Country Energy in conjunction with the IPART cost pass through application. The risk assessment indicated that allocating the additional operating expenditure pass through allowances to general line clearing would provide the greatest benefit for all stakeholders by substantially reducing the risk of electric shocks to staff and the general public reducing the risk of damage to property resulting from fires and improving network reliability and performance for customers.

Country Energy contends that, on this basis, its decision to direct all the operating expenditure pass through allowances to general line clearing is not only in pursuit of compliance with the Design, Reliability and Performance Licence Conditions, but also demonstrates prudent and efficient asset management in its structured approach to the management of network safety risks, and in the optimisation of expenditure per unit of network performance output. It is important to note that the imposed licence conditions include the requirement for compliance with the feeder class reliability standards as well as the individual feeder reliability standards.

---

1 Industry Safety Steering Committee requirements publication entitled "Guide to Tree Planting and Maintaining Safety Clearances Near Powerlines".

Country Energy's approach has resulted in improvements to average network performance and compliance with individual feeder licence conditions. Had this expenditure not been directed to general vegetation work, the average performance of the network would have deteriorated. This may have resulted in Country Energy's non compliance with the imposed Licence Conditions.

In discharging its vegetation management activities over the current *regulatory control period*, Country Energy has acted in accordance with prudent and efficient asset management principles. Moreover, this has been achieved through the application of a targeted and highly effective vegetation management program, underpinned by the need to comply with statutory safety requirements and the imposed licence conditions – with available vegetation management resources allocated on the basis of assessed risk.

Country Energy considers that it would be inappropriate for the *AER* to make a downward adjustment to the forward operational expenditure allowances on the basis of any question over how Country Energy has chosen to optimise expenditure between sub-categories of the imposed Licence Conditions in order to minimise safety risks and to maximise customer network performance.

It is common practice for regulated distribution network service providers (DNSPs) to reprioritise expenditures during a *regulatory control period* due to changing circumstances and risks. This fact has been reinforced publicly by the *AER* on several occasions when it agreed that while expenditure allowances are generally set based on a range of forecast projects, circumstances can change over the course of a *regulatory control period* and as a result DNSPs are not locked into particular projects during a *regulatory control period*. In this regard, the regulatory regime is flexible enough to allow DNSPs to respond to changing investment demands, by reprioritising expenditures.

On this basis Country Energy requests that the *AER* revise the position contained in the Draft Decision and determine Country Energy's forward operating expenditures based on an assessment of prudent and efficient costs, and without sole regard to the methodology used to determine vegetation management projects in the current *regulatory control period*.

Forecast Vegetation Management Expenditures

Country Energy acknowledges that, when making its last submission to IPART, it underestimated the cost of managing the vegetation in proximity to lines. As discussed above, this was primarily due to the fact that the organisation was only formed in 2001. The historical vegetation spend patterns do not accurately reflect the expenditures necessary to comply with the requirements of the Industry Safety Steering Committee.

Prior to submitting its expenditure proposals to the *AER*, Country Energy developed a new methodology to more accurately forecast its vegetation management expenditure requirements in order to fully comply with its Licence Conditions and obligations in respect of reliability, safety and network performance. This new methodology involves adding satellite generated vegetation profiles to all line routes. The vegetation density is analysed across the network and is grouped into low, medium and high density locations. Efficient costs are then generated for the trimming effort required for each density profile. Furthermore, these modelling results have been field-tested prior to finalising the vegetation management expenditure forecasts included in the Country Energy submission. The field testing has continued and the results affirm validity of the modelling used to forecast vegetation management expenses for the next *regulatory control period*. The tests indicate a strong correlation between the vegetation management cost estimates generated by the modelling and the actual costs incurred in carrying out the necessary trimming and removal of vegetation on site.

In addition, and to further check the validity of the methodology, Country Energy has applied this same process to the lines managed by Ergon Energy. The exercise indicates that both Ergon Energy and Country Energy have a similar profile of vegetation densities. After allowing for the differences in cycle duration and network size, it was confirmed that Country Energy's forecast expenditure on vegetation management was comparable to Ergon Energy's incurred expenditure which has been assessed as prudent and efficient by the Queensland Regulator.

Country Energy has an ongoing requirement to meet its safety obligations and also its reliability licence conditions. This involves further improvements in system SAIDI and SAIFI whilst maintaining individual feeder SAIDI and SAIFI targets.

In order to achieve all of these outcomes Country Energy will have to implement new vegetation management strategies. These will include selective "clear to sky" policies for poor performing feeders. This involves the selective removal of tree limbs overhanging the lines which might otherwise result in damage and failure of overhead conductors. Overhead conductors falling to the ground pose material safety and fire risks and lead to interruptions to customer supplies.

Country Energy notes that the *AER*'s consultant, Wilson Cook, did not recommend any adjustment be made to the base-line vegetation management expenditure forecasts included in Country Energy's *regulatory proposal*. Wilson Cook's assessment of Country Energy signified that our forecast operating expenditure is prudent, efficient and necessary. The Wilson Cook report indicated that Country Energy is operating close to or a little below the industry norm. This view is substantiated by the benchmarking analysis included within the report[2].

In its Draft Decision, the *AER* has recommended an adjustment to forecast operating expenditure expenditures of $135.3 million ($2008-09) which is equivalent to the cost pass through operating expenditure allowance agreed by IPART in 2006 for compliance with the imposed Licence Conditions. The adjustment in the *AER*'s Draft Decision is applied to the first three years of the next *regulatory control period*. Country Energy notes that the Draft Decision does not recommend any adjustment to the final two years of the *regulatory control period*. This would seem to imply that the *AER* believes that Country Energy's forward operational expenditures represent prudent and cost efficient forecasts, and has itself acknowledged in the Draft Decision that the expenditure is necessary.

Figure 2 below is based on the benchmarking analysis contained within the Wilson Cook report and has been modified slightly to include the *AER*'s Draft Decision in relation to Country Energy's deferred operating expenditure. This modification is denoted by the "Revised Opex per size" series.

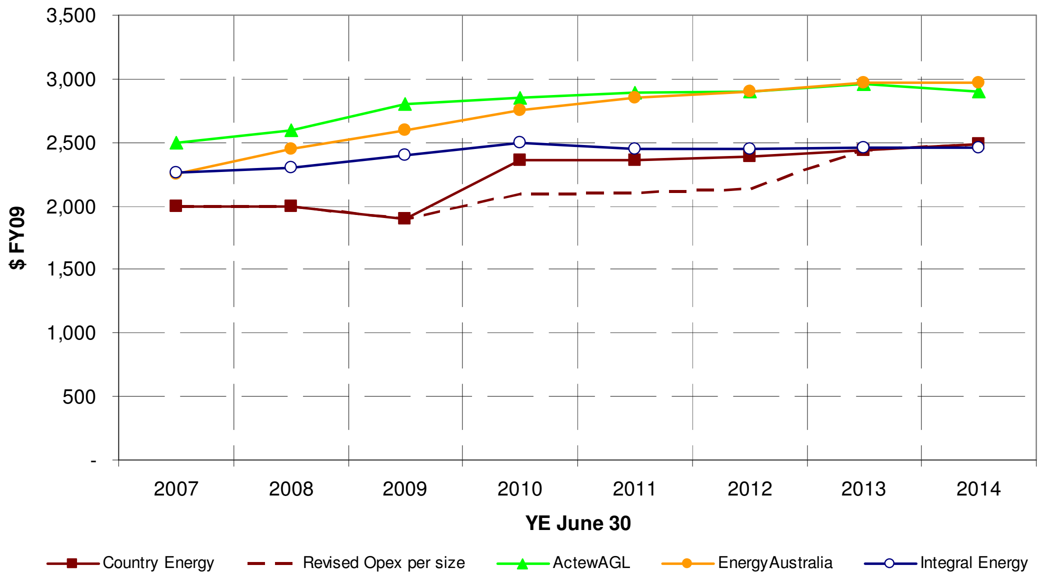

Figure 2 Reproduction of Wilson Cook Opex per Size 2007-14

2 Wilson Cook & Co review of Proposed Expenditure of ACT & NSW Electricity DNSPs, Volume 1, page 25-26

Clearly, the *AER*'s Draft Decision requires Country Energy to continue to operate at levels below other DNSPs until at least 2012-2013. Disallowing Country Energy's deferred operating expenditure substantially disadvantages Country Energy by not providing a sufficient allowance that a prudent operator would require to uphold the *operating expenditure objectives*.

Country Energy confirms that this expenditure level is required for each year of the next *regulatory control period* in order to meet its *operating expenditure objectives* and should not be reduced by $45.1 million (2008-09) per annum for the first three years of the *regulatory control period*, as proposed by the *AER*.

Furthermore, due to the nature of vegetation management expenditures Country Energy believes that had it concentrated on trimming vegetation only on the worst performing feeders and not re-prioritised vegetation management projects according to (AS 4360) risk assessment, total vegetation management expenditures would be substantially unchanged over the six year period commencing in 2006-07. Fundamentally, the cost pass through expenditure allowance would have been spent on the worst performing feeders during the current *regulatory control period* and Country Energy would have continued to spend the allowances on vegetation management included in the IPART submission, after prioritising the works. Moreover, Country Energy believes that this approach would have had minimal impact on improving average system reliability and, more importantly, on risk mitigation.

This approach would also have resulted in higher expenditure levels during the next *regulatory control period* as the costs to restore all vegetation clearances throughout the network in accordance with the Industry Safety Steering Committee requirements would be higher. This is a result of higher trimming costs associated with the removal of vegetation in close proximity to live conductors as either the use of live line crews or outages would be required to carry out the work. In addition, higher costs would be associated with removing and disposing the larger quantity of felled vegetation.

In conclusion, Country Energy contends that:

- all operating expenditure cost-pass through allowances will be spent on general system vegetation management
- these expenditures are prioritised based on risk-assessments and to assist in compliance with Country Energy's reliability licence conditions
- the overall vegetation management expenditure incurred by initially addressing the system vegetation clearing is substantially the same as that which would have been occurred by addressing the worst performing feeders first, but this approach improves the average system reliability and reduces the risks facing the network.
- these actions would be reasonably expected of a prudent network operator.

Accordingly, Country Energy believes that once regulatory allowances are determined, then the prioritisation and development of appropriate operational projects should be left to the network operator on the basis of being best placed to fully understand the asset condition and any specific network management issues. Country Energy contends that the *AER*'s proposed reduction in operational allowances of $45.1 million (2008-09) per annum for the first three years of the next *regulatory control period* is unreasonable in the context of the expectations of prudent and efficient asset management. Therefore, Country Energy requests that the *AER* reviews its Draft Decision in this regard with a view to allowing the necessary operational expenditure level contained in Country Energy's June 2008 *regulatory proposal* and accepted by Wilson Cook as prudent and efficient for each year of the next *regulatory control period*.

4.3 Review of Voltage Regulation Relay Settings and Distribution Transformer Tap Positions

Country Energy's *regulatory proposal* included a proposed program of work for reviewing voltage regulation relay settings and distribution transformer tap positions. The total cost of this program over the next *regulatory control period* was $12.1 million and included in the *regulatory proposal* as part of quality of supply capital expenditure.

During the course of the review of expenditures by Wilson Cook, it was brought to Country Energy's and the *AER*'s attention that this expenditure should have been expensed as an operating cost rather than a capital expenditure item. In consultation with both Wilson Cook and the *AER*, Country Energy agreed with the position of Wilson Cook and confirmed that the program should be moved from capital expenditure to operating expenditure.

In its Draft Decision, the *AER* has correctly removed the program from capital expenditure but has not added it to operating expenditure. Country Energy has therefore completed this task and increased the operating expenditure category of other network maintenance costs by the amount of $12.1 million (2008-09).

4.4 Vegetation Management Asset Growth Escalator

Country Energy believes that the negative adjustment applied by the *AER* in its Draft Decision for the increased operational costs associated with vegetation management in proximity to newly commissioned lines is not appropriate or reasonable. Country Energy believes that the costs for managing the vegetation re-growth associated with these new line routes should be included in Country Energy's forecast controllable expenditures for the period.

Country Energy acknowledges that new line routes are always cleared prior to construction. The costs associated with these works are usually capitalised. However, Country Energy also notes that vegetation clearing cycles are usually based on intervals of either two or three years. This is dependant on a number of issues including the location of the line (rural or urban), historical weather patterns (particularly rainfall and temperature) and the tree species prevalent in the area. Therefore, Country Energy believes that it is reasonable to assume that all newly constructed lines would incur at least one, possibly two, vegetation clearing cycles during the next *regulatory control period*. These cycles include inspection and clearing of vegetation that has encroached into the clearance zone. These inspection and trimming operations incur costs and Country Energy insists that these costs are necessary and require inclusion in the forecast controllable operational expenditures.

It is not appropriate to use the same methodology used to forecast the impact of new assets (commissioned during the *regulatory control period*) on overall controllable operational expenditures at an enterprise level if the asset growth escalator for vegetation management is disallowed. The asset growth escalator was developed as a global ratio and was intended to be applied at a enterprise level. The application of this global ratio, and the associated discount factor, was never intended to be applied at a cost category level. The methodology used to determine the ratio and the associated discount (which reflects the fact that these new assets do not usually require any condition based maintenance during the *regulatory control period* in which they are commissioned) is based on historical enterprise level outcomes and so it is not appropriate to apply these same factors at each cost category level without first testing the validity of outcomes.

It is highly likely that appropriate discount ratios would vary considerably between each cost category and it may also be more appropriate to ratio the cost of the new assets being commissioned against the current replacement costs of similar assets currently in service. For example, for vegetation management expenditures it may be more appropriate to ratio the cost of new lines proposed to be commissioned during the next *regulatory control period* to the current replacement cost of all the Country Energy lines in service. An appropriate discount factor would then be applied to reflect the inherent delay between commissioning the first vegetation inspection and trim.

Country Energy contends that the additional operational costs associated with maintaining appropriate vegetation clearances to new assets constructed during the next *regulatory control period* represents prudent maintenance practices and the methodology used by Country Energy to determine these costs results in efficient expenditure forecasts. Therefore, these costs should be included in the forecast operational expenditures for the next *regulatory control period*.

4.5 Forecast Costs of *Sheather* Decision

Country Energy's *regulatory proposal* included certain costs arising from the decision in the case of *Sheather v Country Energy* (*Sheather*) as a nominated pass through event. The *AER*'s Draft Decision rejected this, and stated that the most appropriate time for Country Energy to seek to pass through any cost changes is at the time of a regulatory reset. Therefore, given it is expected that costs will start being incurred by Country Energy during the next *regulatory control period*, a forecast level of operating expenditure has been developed by Country Energy for inclusion in this revised *regulatory proposal*.

Background

Since 1999 Country Energy and its predecessors have been involved in three incidents resulting in fatalities as a result of helicopters coming into contact with powerlines. In the first incident (Sheather 1999) the New South Wales Court of Appeal ruled that Country Energy owed a duty of care to the aircraft owner, notwithstanding that the pilot was flying below the mandatory height. A subsequent application to seek leave to appeal to the High Court was rejected.

A Coronial Inquest was held into two subsequent helicopter incidents which occurred in Dunedoo (2004) and Parkes (2006), with the Coroner recommending:

- immediate and urgent action is taken to mark the power line near Parkes, which has already been implemented by Country Energy
- Country Energy conduct a study of all "at risk" power lines and formulate a strategy to mark these lines
- Country Energy considers the painting of power support poles and ensure that easements remain clear of vegetation

Following the decision in *Sheather*, Country Energy established a risk management system to evaluate the risk of helicopters and fixed wing aircraft coming into contact with its lines and establish a strategy to mitigate this risk.

To date Country Energy has determined that it will investigate lines with a span in excess of 750 metres, as the Sheather and Parkes incidents involved long spans. A total of 1,124 such spans have been identified with lengths between 750 and 1600 metres. Country Energy's database does not identify the height above ground level of these spans. However, Country Energy has identified new spatial technology that will enable Country Energy to overlay these spans on a three-dimensional map of New South Wales. This will enable Country Energy to identify the height above ground level as well as the topography of the surrounding area.

The length, height and surrounding topography will be used as the initial filters to establish a risk matrix. The matrix will be refined following a survey of the spans undertaken during the normal asset inspection process. The survey will address a number of factors including:

- Surrounding land use
- Visibility of the lines
- Surrounding aircraft flight paths
- Location of hang gliding clubs and the like
- Any other factors considered relevant by the working group

Country Energy will consider risk mitigation actions including but not limited to:

(1) accept the risk and:

- place a limited number of markers above roadways by means of high tower, aerial attachment or dropping the line
- mark the line in accordance with the Australian Standard by means of high tower, aerial attachment or dropping the line, or
- relocate the line; and

(2) painting poles (although investigation to date has not identified any practical solution).

Country Energy has developed forecast costs for mitigating the risk of these legal decisions. Country Energy assumes that 50 per cent of the 1,124 spans will require remedial action. It is proposed that the work be carried out over a 10 year period with work commencing from 1 July 2010 on the highest risk spans. This will allow sufficient time to refine the risk matrix and efficiently plan the work. It is further assumed that the average remedial action will be to install markers on the line in accordance with AS 3891.1 and that the supporting poles will have to be upgraded to carry the additional weight.

Country Energy has calculated the total cost of pole replacement and line marking to be $40.2 million (2008-09). Country Energy has therefore increased the operating expenditure category of other network maintenance costs by the amount of $10.06 million per annum commencing 1 July 2010.

4.6 Self Insurance Costs

In its Draft Decision the *AER* has reduced the forecast operating expenditure for self insurance allowances by $4.5 million to $15.0 million for the next *regulatory control period*.

In its Draft Decision, the *AER*:

a) Considered Country Energy's proposed self insurance allowances for fraud risk, insurers' credit risk, counterparty credit risk, key assets risk and risk of non-terrorist impact of planes and helicopters to be appropriate
b) Reduced self insurance allowance by $55,000 for Bomb threat/hoax, terrorism events
c) Reduced overall self insurance allowance for Earthquake by $85,000
d) Reduced bushfire self insurance allowance by $2.7 million
e) Reduced poles and lines self insurance allowance by $1.4 million
f) Reduced key persons risk self insurance allowance by $210,000
g) Reduced overall self insurance allowance for General public liability risk by $45,000.

Country Energy has not implemented the *AER*'s Draft Decision in relation to the proposed reductions listed above. Country Energy engaged SAHA to review the *AER*'s Draft Decision on self insurance allowances and provide additional supporting evidence for validation of the allowance calculations.

The remainder of this chapter discusses the assessment of:

- terrorism risk
- earthquake risk for magnitude 6 earthquakes
- bushfire risk
- poles and lines risk
- key person risk
- general public liability risks

Terrorism risk

In the Draft Decision, the *AER* has rejected Country Energy's proposed $11,000 per annum self insurance premium for the cost impact for acts of extortion or bomb threats pertaining to a terrorist related event indicating:

- there is difficulty associated with calculating a risk premium
- 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 for eligible insured assets as a result of a stated terrorist act and
- under the NER a terrorism event is a defined pass through event.

Country Energy accepts the *AER* decision in principle but has concerns about the possibility of a pass through application failing to fully compensate Country Energy for the costs of such an event given the materiality threshold for cost pass through events.

Country Energy believes there is potential for negative financial repercussions unless there is either acceptance of the original proposed self insurance premium (of $11,000 per annum) or clear guidance on the materiality threshold that should apply for truly negative asymmetric risks for DNSPs. Refer to section 4.2 of appendix B.

Earthquake risk

In the Draft Decision, the *AER* has rejected Country Energy's proposed $17,000 per annum self insurance premium for the cost impact of a magnitude 6 earthquake indicating that there is no historical observations of magnitude 6 earthquakes in NSW in the last 166 years, and as such, earthquake prediction could be considered virtually impossible.

Country Energy believes that the *AER*s decision implies that because the risk is not supported by historical data that the risk doesn't exist and as such Country Energy should not be compensated for the costs of such an event in the future. Although the long data set suggests that a magnitude 6 earthquake event has not occurred in the last 166 years, does not mean that there isn't a risk of it occurring sometime in the future.

Country Energy considers that there is a genuine risk of a magnitude 6 earthquake occurring in the future and that the reduced premium compared to its magnitude 5 earthquake risk premium is reflective of the reduced likelihood of this risk occurring. As such Country Energy proposes the re-instatement of its original proposal of $17,000 per annum self insurance premium for magnitude 6 earthquake risk. An alternative approach that the *AER* may wish to consider to ensure adequate DNSP compensation would be to allow earthquakes greater than magnitude 5 to be included as pass through events.

Bushfire risk

In the Draft Decision, the *AER* has rejected Country Energy's proposed $540,000 per annum self insurance premium for the cost impact pertaining to bushfire damage indicating:

- 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 fact that one 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 one 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) which 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.

SAHA's review of this allowance is included in section 4.4 of appendix B. Country Energy considers the original self insurance premium proposed remains an accurate estimate of bushfire risk and proposes the reinstatement of $540,000 per annum self insurance premium for bushfire risks.

Poles and lines risk

In the Draft Decision, the *AER* has rejected Country Energy's proposed $279,000 per annum self insurance premium in relation to damage to poles and lines as a result of a catastrophic storm indicating:

"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".

Country Energy provides additional supporting documentation of storm events occurring across NSW to support its original proposal in section 4.6 of appendix B.

Key persons risk

In the Draft Decision, the *AER* has rejected Country Energy's proposed $42,000 per annum self insurance premium in relation key persons risk indicating that:

- 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
- 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
- It was 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.

Country Energy believes that the *AER* has misinterpreted the identification and assessment of the likelihood of one of Country Energy's key employees causing an adverse financial impact due to the sudden departure or death provided by Country Energy as a calculation based on the event happening for all key employees in the one year. The probability of each key employee leaving in any year mostly equate to approximately 1.5% - 2%, or once every 50 – 75 years approximately. As such Country Energy refers the *AER* to section 4.8 of appendix B for clarification and further detail regarding the original proposal and request consideration for the inclusion of a $42,000 per annum self insurance premium in relation to key persons risk.

General public liability risk

In the Draft Decision, the *AER* has rejected Country Energy's proposed $9,000 per annum self insurance premium in relation general public liability risk indicating that there are no instances of claims being experienced by Country Energy since its inception seven years ago.

Country Energy believes that the *AER*'s Draft Decision again implies that because the risk is not supported by historical data that the risk doesn't exist and as such Country Energy should not be compensated for the costs of such an event in the future. Although the history of Country Energy is relatively short at seven years, Country Energy believes events occurring within other DNSPs within NSW should be indicative of the likely risk of an event occurring in Country Energy's distribution network. Country Energy therefore seeks reinstatement of the originally proposed self insurance premium of $9,000 per annum above deductible general liability claims for compensating for the cost impact of general public liability risk.

The total self insurance premium proposed by Country Energy is shown in Table 6 below.

$M (2008-09)	2009-10	2010-11	2011-12	2012-13	2013-14	Total
Self Insurance	3.9	3.9	3.9	3.9	3.9	19.5

Table 6 - Self Insurance allowance

4.7 Debt Raising Costs

In its Draft Decision, the *AER* reduced Country Energy's debt raising cost forecast by $11.4 million to $12.6 million over the next regulatory period.

Country Energy engaged CEG to review the *AER*s Draft Decision on debt raising costs and provide additional supporting evidence for the calculation of debt raising costs.

Country Energy maintains that the *AER* should consider the inclusion of indirect debt raising costs as they are a legitimate operating expense that is a significant portion of the total real world cost of raising debt. Country Energy maintains its current position on the cost of raising debt and provides supporting information showing the need for regulators to take into account these additional costs in the independent CEG report included at Appendix C.

The projected debt raising costs for each year of the next *regulatory control period* proposed by Country Energy are summarised in the Table 7 below.

$M (2008-09)	2009-10	2010-11	2011-12	2012-13	2013-14
Debt Raising Costs	4.0	4.5	5.0	5.6	6.1

Table 7 - Debt and equity raising costs from 1 July 2009 to 30 June 2014

4.8 Operating Expenditure Cost Escalators

The *AER*'s Draft Decision recognised Country Energy's proposal that it is necessary to determine a price index that encompasses more than CPI when escalating the relevant inputs employed in operating and maintenance activities. However, the *AER*'s Draft Decision also disregarded some cost escalators, amended the methodology in other areas and updated Country Energy's proposal for the latest data available.

Country has implemented some aspects of the *AER*'s decision on operating expenditure cost escalators including:

- Escalating vegetation management contractors by the general wage escalator rather than the Electricity Gas and Water (EGW) wage escalator; and
- Using a value of zero for producers margin.

However, Country Energy does not accept the *AER*'s Draft Decision on other cost escalators or methodologies employed. Country Energy has maintained the methodology used in its *regulatory proposal* (apart from the instances noted above), updated for the latest data available at the time of the submission of this revised *regulatory proposal*. The expenditure forecasts presented in this revised *regulatory proposal* are in real terms including market expectations of real wage increases combined with actual historical increases, and material/equipment cost increases based on an updated report from the Competition Economists Group (CEG), attached as appendix D. The CEG report outlines the reasons for Country Energy's approach and addresses some of the concerns Country Energy has with the *AER*'s Draft Decision.

4.9 Summary of Efficient Operating Expenditure Forecasts for the Next *Regulatory control period*

Country Energy's revised forecast of operating expenditure relating to *standard control services* for the next *regulatory control period,* assuming a base growth scenario, is summarised in * Numbers may not add due to rounding.
Table 8 below.

Country Energy has retained its forecast productivity gains in resourcing its internal programs of work in accordance with Country Energy's resourcing plan. Country Energy has also retained a reduction to its forecast fault and emergency related expenditure to offset expected system improvements resulting from the proposed reliability, refurbishment and renewal capital expenditure and vegetation management projects.

$M (2008-09) *	2009-10	2010-11	2011-12	2012-13	2013-14
Network Operating Costs	18	18	18	19	19
Network Maintenance Costs					
- Inspection	39	40	41	42	44
- Pole replacement	2	3	3	3	3
- Maintenance and repair	68	80	82	84	86
- Vegetation Management	102	106	109	113	116
- Emergency Response	50	52	53	55	56
- Other Network Maintenance Costs	88	91	94	96	99
Other Costs					
- Meter reading	20	20	21	22	22
- Customer service	14	14	15	15	15
- Advertising, marketing and promotions	5	5	5	5	5
Self insurance costs	4	4	4	4	4
Debt raising costs	4	5	5	6	6
LESS: Productivity savings	(2)	(4)	(4)	(4)	(4)
LESS: Opex/capex tradeoff	(1)	(2)	(3)	(4)	(5)
TOTAL OPERATING EXPENDITURE	**411**	**432**	**445**	**457**	**467**

* Numbers may not add due to rounding.

Table 8 - Forecast Operating and Maintenance Expenditure for Standard Control Services

Directors' Certification Statement

In accordance with Rule S6.1.2(6) of the transitional *Rules*, this revised *regulatory proposal* must contain a certification by the Directors of Country Energy of the key assumptions underlying the operating expenditure forecasts. The Directors' certification statement is attached at appendix E.

Capital Expenditure

5 Capital Expenditure

5.1 Overview

Chapter 5 of Country Energy's *regulatory proposal*, dated June 2008, described the methodology used to develop capital expenditure forecasts for the next *regulatory control period*. Key inputs and assumptions underpinning the capital expenditure forecast were also detailed.

In its Draft Decision, the *AER*:

a) Accepted that Country Energy's documented policies and procedures outline a sound framework for facilitating investment aimed at achieving the capital expenditure objectives

b) Found that Country Energy's governance arrangements supported the prudence and efficiency of the proposed capital expenditure

c) Considered Country Energy's maximum demand forecast methodologies and forecasts provide a realistic expectation of the demand forecast required to achieve the capital expenditure objectives

d) Accepted that the unit cost estimates used by Country Energy reflect efficient cost inputs

e) Accepted Country Energy's augmentation and growth related capital expenditure reflects efficient costs that a prudent operator would require to achieve the capital expenditure objectives

f) Accepted Country Energy's replacement capital expenditure reasonably reflects the efficient costs that a prudent operator would require to achieve the capital expenditure objectives

g) Accepted Country Energy's reliability capital expenditure reasonably reflects the efficient costs that a prudent operator would require to achieve the capital expenditure objectives, but removed $12.1 million to reflect that costs for review of voltage regulation relay settings and distribution transformer tap positions should be expensed rather than capitalised

h) Accepted Country Energy's environmental, safety and statutory capital expenditure reasonably reflects the efficient costs that a prudent operator would require to achieve the capital expenditure objectives

i) Did not accept Country Energy's proposed cost escalation factors and substituted revised escalators and updated CPI calculations

j) Did not accept real cost escalation for non system capital expenditure; and

k) Did not accept Country Energy's forecast non system capital expenditure of $684 million and decided on the following adjustments:

   - $65.6 million reduction to forecast IT capital expenditure, and
   - $20.8 million reduction to non system land and building capital expenditure.

Country Energy has implemented the majority of the *AER*'s Draft Decision described above with the exception of the following:

- Information technology (IT) non system capital expenditure

- Land and buildings non system capital expenditure
- Certain substituted cost escalators
- Real cost escalation for non system capital expenditure
- 2007-08 forecast capital expenditure has been updated with actual capital expenditure from that financial year, and
- Methodology for calculating equity raising costs.

The remainder of this chapter is structured as follows:

- Section 5.2 presents further information on Country Energy's IT non system capital expenditure forecasts
- Section 5.3 addresses concerns raised by the *AER* on Country Energy's land and buildings forecasts
- Section 5.4 details Country Energy's revised cost escalators used in developing the capital expenditure forecasts
- Section 5.5 discusses the rationale for applying real cost escalation to non system capital expenditure
- Section 5.6 presents actual capital expenditure for the 2007-08 year
- Section 5.7 details Country Energy's equity raising costs and methodology, and
- Section 5.8 summarises Country Energy's capital expenditure forecasts for the next *regulatory control period*.

5.2 Non System Capital Expenditure – Information Technology

As a key component of Country Energy's forecast capital expenditure over the next *regulatory control period*, the business has sought to include $256 million ($2008-09) of prudent and efficient information and communications technology related expenses.

Specifically, expenditure in this category relates to non-system information technology (IT) systems development and upgrades, computer hardware, software and licences, as well as telecommunication systems and plant. Investment in these areas is fundamental to ensure that the strategic objectives contained in Country Energy's *Network Asset Management Plan* (*NAMP*) can be met, and will enable it to:

- leverage ongoing investment strategies to support the planning and operation of the distribution network
- enhance its knowledge of the condition of assets and data gathering to optimise future investment
- manage the delivery of its increased capital works plan, and
- ensure compliance monitoring requirements and ongoing regulatory obligations are met.

Key sub-components of the forecast include:

- a review and replacement of critical asset management systems
- a review and replacement of the customer information system
- a review and replacement of the meter data management system
- upgrades to the network quality monitoring system, and
- ongoing and routine expenditure to maintain standards and meet growth in the number of users.

The forecast of IT expenditure has been internally prepared in accordance with current standards and policies, needs, required quantities, and the age of the assets. The related policies and procedures underpinning the development of the forecasts include:

- Country Energy Information and Communications Technology (ICT) Strategy 2007 to 2010 (November 2007)
- Country Energy ICT Strategic Plan 2007 to 2010 (November 2007)
- Charter of Corporate Services Project Management Office
- Charter of the ICT Council
- ICT council risk assessment framework
- the IT asset register as maintained in Country Energy's financial systems, and
- a well developed list of Policies and Procedures relating to IT capital allocation and management.

The above policies and procedures are contained within Country Energy's IT work plan (2009-14) attached as appendix F on a commercial in confidence basis.

Country Energy's historical expenditure during the current *regulatory control period* for non-system IT amounts to $153 million ($2008-09). The significant increase in IT related capital expenditure in the next *regulatory control period* compared with this level is associated with the age and performance of existing assets and the timing of key strategic projects. These projects include the development of an Enterprise Management System, which includes replacement of the asset management system and upgrade and integration of the customer information system. In essence, Country Energy is presented with the challenge of needing to replace two of its major and critical information systems within the next *regulatory control period.* In addition, Country Energy will replace its meter data management system. The main reasons for replacing these systems during the next *regulatory control period* is that they have reached end of life, require significant modification and are becoming increasingly difficult to support and manage.

The historical spend is approximately 9 per cent above the 2004 IPART allowance. This is recognition of Country Energy's position that historical investment in critical IT systems was restricted, business needs were not being met, and identified opportunities were not being realised. A change in approach to IT investment coincided with Country Energy's high level review of internal processes, and a risk assessment of its legacy (multi-business originated) systems in 2006. Since this time, Country Energy has:

- adopted a balanced scorecard IT capital allocation prioritisation methodology (in-lieu of the budget drivers annual prioritisation process previously used)
- developed IT Principles and Architecture policies to guide selection, development and maintenance of IT assets
- established a skilled Project Management Office, with standard templates, financial business cases and project methodologies
- strategically moved from annual project to multi-year program-based cycles of work, and
- developed internal system capacity to manage staff/contractor resource availability and allocation.

While Country Energy recognises that the investment framework it has put in place is relatively new, it believes that it is well positioned to deliver upon a considered and targeted IT investment strategy for the next *regulatory control period* and beyond.

Country Energy strongly believes that its IT expenditure governance and decision making framework, coupled with its bottom-up project identification underpins the overall efficiency and prudence of the forecast capital expenditure investment. Country Energy also believes that this level of investment is suitable for a regionally based business given the current state of its IT investment cycle.

AER Draft Decision

The *AER* engaged Wilson Cook to undertake a detailed review of the prudence and efficiency of Country Energy's non-system capital expenditure for IT related purposes.

Importantly, Wilson Cook concluded that Country Energy's proposed investment was related to IT systems that are typical in an electricity distribution network business, however the scale and scope of the expenditure was large and well in excess of historical expenditure.

Wilson Cook recommended a reduction of 25 per cent of the IT forecast allowance (which equates to $65.6 million) to reflect the fact that Country Energy's IT expenditure was, in the view of Wilson Cook, not adequately justified at a project level, and that it also appeared high in comparison to other DNSPs.

The magnitude of the proposed reduction in Country Energy's allowance has been informed primarily through a top-down benchmarking exercise whereby the IT expenditure of five distribution businesses was compared using a composite normalising component recognising the characteristics of the number of network customers, the network feeder length, and the peak demand experienced by the system.

As part of its Draft Decision, the *AER* agreed with Wilson Cook's findings that the proposed expenditure appears high in comparison to the other businesses, and was not sufficiently justified in financial terms. On this basis, the *AER* has accepted the advice of Wilson Cook that non-system IT capital expenditure should be reduced by 25 per cent in order to bring it to a level which is comparable with the other DNSPs in terms of benchmarking outcomes, and therefore considered efficient.

Review of Wilson Cook's IT expenditure benchmarks

In this section, Country Energy responds to the merits and the basis of Wilson Cook's benchmarking process by making a number of general and specific observations. Specifically, the following key elements are considered in turn:

- the appropriateness of focussing on a top-down inter-business benchmark to inform the efficient level of a businesses ex-ante IT capital expenditure allowance
- the need to consider individual business strategies and decisions, and the interaction between operating expenditure and capital expenditure levels in order to determine prudent and efficient expenditure
- the transparency of reproducing Wilson Cook's IT expenditure benchmarks on a cost per customer and cost per size basis
- recognition that the application of other normalising factors as part of a benchmark exercise could lead to very different outcomes and therefore provide a very different view of the efficiency of Country Energy's IT expenditure relative to its peers, and
- examination of historical and proposed IT expenditure to illustrate the long-term trend in expenditure.

Application of top-down benchmarks to determine efficient capital expenditure

In Country Energy's opinion, the application of high-level expenditure benchmarking using ratio analysis should predominantly be used to provide an initial and preliminary inter-business comparative indication of expenditure across various operating expenditure and capital expenditure investment categories. It provides one insight only, under highly qualified boundary conditions, and it should not be applied as a key analysis tool through which the efficiency of expenditure for a single business, or even the wider peer group as a whole is gauged.

As discussed by Wilson Cook in the context of the expenditure comparisons it has undertaken:

"It is acknowledged that benchmarking has limitations and thus, whilst broad comparisons of the expenditure of DNSPs may be made, various factors complicate the comparisons and require the exercise of considerable judgement when interpreting the results.

It is also acknowledged that any comparison of a particular business with others implicitly assumes that the other businesses are efficient and the services provided are comparable in nature and quality." [3]

Country Energy's key observations regarding the application of the top-down benchmarking include the following:

- that it is not clear what degree of judgment the *AER* or Wilson Cook have incorporated into the Draft Decision
- the Draft Decision implicitly assumes that the other businesses benchmarked are efficient, and that the services provided are comparable in nature and quality
- that the adopted benchmarking normalisers and network characteristics are accurate and suitable for the purposes of defining efficient expenditure
- there appears to be, fundamentally, no limitations regarding the application of high-level benchmarking
- it is not clear how the efficient level of IT capital expenditure has actually been established, and why the approach is considered suitable by Wilson Cook and the *AER* for IT capital expenditure but it is clearly not suitable for network related capital expenditure, and
- the lack of a balanced outcome to suggest that the IT capex allowances for businesses operating below the peer group average may not need to be increased to ensure efficient and prudent expenditure levels have been set on a consistent basis across all the businesses.

Critically, Country Energy is of the opinion that the approach endorsed and promulgated by the *AER* to quantify the downwards adjustment to its IT capital expenditure has not accounted for:

- the unique network characteristics, environment and underlying drivers facing the business, particularly the age of its existing legacy systems
- the total life-cycle aspects of a well considered and approved IT investment strategy, and the efficiency opportunities it presents through the enterprise-wide integration of key systems
- the business and technical risks facing Country Energy, should prudent and efficient levels of expenditure not be approved.

IT expenditure benchmarks and normalisers

In this section, Country Energy considers and comments on the IT capital expenditure benchmarks presented by Wilson Cook based on the 'cost-per-customer' and the composite 'cost-per-size' normalised basis.

Consistent with the qualifying statements expressed by Wilson Cook[4], Country Energy also recognises that any comparative assessment relies on the availability of data, and the level of accuracy and comparability of the source data. Consideration must be given to:

- leasing rather than owning of IT assets - it is presumed that leasing would result in higher levels of operating expenditure and lower levels of capital expenditure compared to a business that owns its IT assets. The benchmarking conducted by Wilson Cook indicates that at least one of the DNSP's leases rather than owns its IT assets[5]. Benchmarking IT capital expenditure becomes problematic as the nature of the expenditure is not consistent and this may skew results when viewed in isolation

[3] Wilson Cook main report, page 17
[4] Wilson Cook main report, page 17
[5] Wilson Cook report, Volume 5, page 25

- consistency in managing IT capital expenditure - Country Energy manages all IT capital expenditure within the divisional IT capital expenditure allowances and budgets. It is not clear to Country Energy if other DNSPs manage IT expenditure in the same way. For example, Country Energy's Fibre to Zone project (detailed within Country Energy's IT workplan 2009-2014) is budgeted for and managed by Country Energy's Information Services division. It may also be accurate to budget this expenditure within system capital expenditure and other DNSPs may have budgeted similar expenditure in this way. This illustrates again that businesses may not comparable on a like for like basis.
- appropriateness of benchmarking - Country Energy's major IT system needs would not differ greatly to any other large DNSP. Country Energy's total IT capital expenditure does not differ greatly to that of EnergyAustralia, since numbers of customers and size have no real connection to IT capital expenditure. For example, the cost of a replacement asset management system would not differ greatly between the two DNSPs because similar systems are required for both businesses with no real differentiation in those systems due to customer numbers or size.
- separating business as usual IT capital expenditure and new systems and replacement expenditure from the benchmark comparison - when comparing IT capital expenditure between DNSP's it is common practice to separate out significant or transformational projects for new systems expenditure simply because different organisations have different application portfolio mixes in terms of where their systems are in the systems life cycle. It is more realistic to compare the systems mix on a like for like basis between organisations.
- the systems life cycle in assessment of the IT capital expenditure - life cycle systems replacement whether driven by technology, business, regulatory requirements or amalgamations does not align exactly with regulatory determination periods or other businesses.

Sensitivity and reasonableness of benchmarks

As discussed above, there are clear limitations in benchmarking IT capital expenditure. Furthermore, the benchmarking exercise undertaken by Wilson Cook, particularly the use of a composite 'size' based normalising factor, is flawed when it is applied is to determine an efficient IT capital expenditure level across a small group of businesses. This is due to the selection of the three key business indicators proposed and the assumptions regarding how each one is proportioned to arrive at the composite index.

The individual and widely varying characteristics of the NSW DNSPs reviewed create factors that are difficult to account for when comparing such different businesses, as parameters can vary significantly. This is desensitised by averaging the proposed expenditure over the next *regulatory control period* to capture the time varying nature of IT capital expenditure, but this does not provide for a sufficient basis to inform efficient capital expenditure levels. Although EnergyAustralia has the highest number of customers of the NSW DNSPs, Country Energy's network in comparison has the largest geographic coverage (as represented by total network length). Fundamentally, the parameters vary significantly across the businesses. An attempt to account for these differences was made as part of the Wilson Cook analysis by the use of the Ofgem[6] informed composite variable of the form:

Composite Size = (Customers0.5 x Length0.3 x Demand0.2)

The two sets of benchmarks presented by Wilson Cook are either exclusively dependent on customer numbers ($/Customer), or strongly biased towards customer numbers ($/Size, where the customer number is raised to a power of 0.5). As a direct result of the selection of these benchmarks, Country Energy's IT expenditure profile will invariably perform poorly relative to its peers. Country Energy considers that normalising factors that recognise its specific characteristics (such as geographic area, line length or other relevant factors not discussed by Wilson Cook such as average IT asset age or the number of staff) may be more appropriate and better indicators of IT and communications related capital expenditure. Fundamentally, the Wilson Cook IT capital expenditure benchmarks are unfairly biased towards the number of customers serviced by the network, and it could be argued that line length should be used as an equally weighted normalising factor.

[6] Ofgem is the economic regulator for electricity and gas markets in Great Britain

Regression analysis undertaken by Country Energy actually suggests that the level of IT capital expenditure is more closely correlated (i.e. higher R-squared parameters) to line length (per km of feeder) compared to customer number inputs.

As an extreme example to highlight the sensitivity to key input assumptions, when focussing purely on dollars spent per km of feeder, the IT capital expenditure for the other NSW DNSP's varies from between 2.7 to 4.1 times Country Energy's. This outcome undermines the reasonableness of the application of the benchmarking ratios presented by Wilson Cook in the manner that it has been used, and therefore the basis of its 25 per cent downwards adjustment to Country Energy's IT capital expenditure.

IT investment strategies and overall IT expenditure

Country Energy's IT investment expenditure is uniquely characterised among NSW and other regional DNSPs by the geographical extent and diversity of its supply area, its substantial overall line and feeder length, and government initiatives to maintain a local presence and workforce in regional areas across NSW. This gives rise to a relatively high user base, for which a very high correlation with IT capital expenditure has typically been reported for utilities.

Within the context of Country Energy's IT investment requirements, there are some 66 manned IT-serviced sites, including 3 call centres and operational service centres handling customer and emergency calls and providing field support. Moreover, for safety and other operational reasons, Country Energy has been required to implement its own private radio infrastructure and service given the absence of full or guaranteed coverage from commercial service providers, or other government emergency infrastructure.

Each of these aspects has been taken into account as part of the detailed IT strategy development driven by the ICT Council, which is primarily focussed on establishing enterprise wide, contemporary and well supported IT infrastructure platforms that capture all of the businesses key processes. This is coupled with a workforce that is mobile, efficient and ready to respond to the increasing demands of the developing distribution network. It is not clear to Country Energy how each of these specific and often unique aspects has been considered as part of the Wilson Cook assessment and the *AER*'s draft decision.

Furthermore, as part of the *AER*'s draft decision it is not clear to what extent the balance between IT capital expenditure and IT operating expenditure investment has been made across the businesses under review. In comparison with many other utilities with whole-of-business contracts, Country Energy employs a relatively low level of IT outsourcing of major infrastructure and systems, preferring instead to undertake selective market testing, partnering and sourcing. This approach is based on leveraging off the existing skill sets within Country Energy and will have the tendency to increase capital expenditure requirements when viewed in isolation from operating expenditure. Specifically, Country Energy is not aware of the considerations that have been given to the overall balance of IT investment across both capital expenditure and operating expenditure for each business when arriving at its decision on the efficiency of Country Energy's IT capital expenditure proposal.

Country Energy historical capital expenditure trends

As of 30 June 2009, the Country Energy opening asset value for IT systems is expected to be around $95m with an average remaining life of only 1.9 years, compared with the standard life of 5 years. Fundamentally, Country Energy is at a position within its IT asset lifecycle that requires a considerable degree of replacement driven investment that is not discretionary given the key dependence on systems that are used by staff across the entire business. This will raise Country Energy's IT systems to a more sustainable and risk averse level, in line with customer expectations and good electricity industry practice.

Bottom-up justification

Country Energy has attached a work program covering the period 2008/09 to 2013/14 to this revised *regulatory proposal* (refer to appendix F). This program has been provided as commercial in confidence. The works program provides background information and Country Energy's IT principles and objectives, and is underpinned by plans, procedures and processes as described above.

Country Energy is forecasting IT capital expenditure over the 2009/10 – 2013/14 period to be $256 million ($2008/09) in order to cover prudent and efficient information and communications technology related expenses.

Specifically, expenditure in this category relates to non-system information technology (IT) systems development and upgrades, computer hardware, software and licences, as well as telecommunication systems and plant. Investment in these areas is fundamental to ensuring that the strategic objectives in Country Energy's NAMP can be met.

As part of Country Energy's Enterprise system review, the following key sub-components of the forecast include:

- a review and replacement of critical asset management systems at a cost of $55.5 million
- a review and replacement of the customer information system at a cost of $28.1 million
- a review and replacement of the meter data management system at a cost of $14.7 million, and
- ongoing and routine expenditure to maintain standards and meet growth in the number of users at a average annual cost of $31.4 million

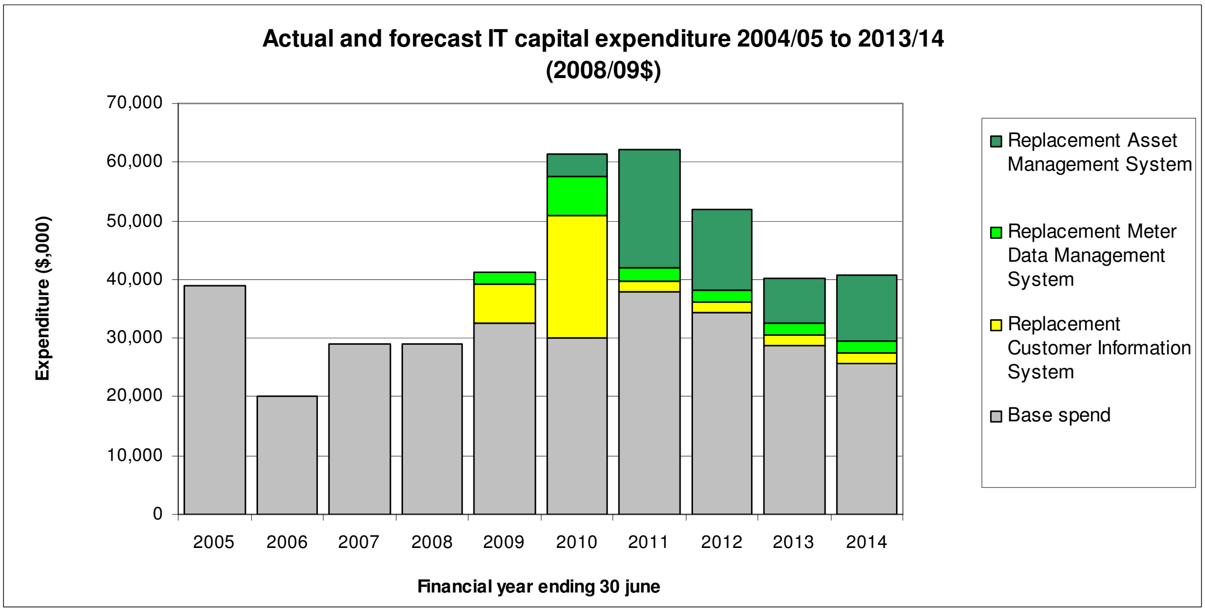

Figure 3 Actual and forecast IT capital expenditure 2004-05 to 2013-14 ($2008/09)

As shown in Figure 3, Country Energy's historical capital expenditure during the current *regulatory control period* for non-system IT amounts to $150 million. The significant increase in IT related capital expenditure for the 2009/10 to 2013/14 period is driven by key strategic projects being the replacement of the asset management system, meter data management system and customer information system. Excluding these key strategic projects, Country Energy's forecast IT related capital expenditure is in the order of $156.8 million.

Further to the planned major system replacements, Country Energy is forecasting expenditure for other non discretionary items. For example:

- The Fibre to Zone project is required to address non-compliance and safety issues related to earth rise potential hazards at sites, and
- Field Force Automation is required to address reduced capability, speed and accuracy when responding to emergencies that result in poor reliability and loss of field based knowledge and asset condition data. Increasing capability in this area will improve efficiency of planning and replacement investments.

The projected expenditure over the 2009/10 to 2013/14 period is forecast to be generally consistent with historical spend, excluding the three major system replacements. The level of expenditure on information systems may fluctuate from one *regulatory control period* to another because of the need to replace or upgrade systems that were not implemented in a previous *regulatory control period*.

Fundamental to the strategic decision to replace the current core business systems is the reality that all of the systems have reached end of life. Further, Country Energy is also faced with the following risks:

- lack of integration between systems, data and processes resulting in business inefficiencies
- the systems life cycle has converged to a point where some major business systems all require replacement within the next few years
- additional operating expenditure will be required to maintain and support systems which have reached end of life
- the vendors of Country Energy's main IT systems - major systems are either supported by small operations or the vendor is exiting the market for certain products. This may result in systems becoming unsupported.

Country Energy's business is therefore presented with increasing risk. More importantly it presents risk to the prudent and efficient deployment and management of around $4,000 million of network capital expenditure over the next *regulatory control period*.

Conclusion

Country Energy's forecast of IT expenditure over the next *regulatory control period* has been internally prepared in accordance with current standards and policies, needs, required quantities, and the age of the assets.

Country Energy considers the $256 million (real 2008/09) proposed, covers what it believes to be prudent and efficient information and communications technology related expenses for a business characterised by its regional nature and given the condition and age of its existing assets. Specifically, the large increase in expenditure is required to establish enterprise wide, integrated IT platforms focussed on contemporary and critical asset management and customer information systems.

Country Energy considers the approach adopted and the degree of adjustment proposed by the *AER* as part of its draft determination lacks clarity and has not been appropriately supported. Specifically, Country Energy considers:

- High-level benchmarking and ratio analysis should not be applied to determine efficient levels of IT capital expenditure
- Application of benchmarking in this manner is unprecedented and lacks transparency
- The selection and weightings applied to the normalising parameters are not reflective nor appropriate to inform efficient IT capital expenditure, and are highly variable and sensitive across the peer group
- The selection and weightings applied to normalising parameters are strongly biased towards customer numbers, therefore regional network businesses will invariably perform poorly
- Country Energy benchmarks reasonably well when considering capital expenditure as a ratio of line length or staff numbers

- Sufficient consideration must be given regarding the strategy, processes and governance associated with Country Energy's IT investment plans
- Country Energy has supported its proposal with detailed risk assessment from a bottom-up perspective discussing the scope of work, the cost, the need, timing, alternatives considered and strategic alignment
- The average remaining life of Country Energy's IT systems assets in July 2009 will be only 1.9 years, indicating a real need to undertake nondiscretionary replacement expenditure.

5.3 Non System Capital Expenditure – Land and Buildings

In its Draft Decision the *AER*, based upon a recommendation by Wilson Cook, has reduced the forecast capital expenditure for non system land and buildings by $20.8 million. The *AER* has also eliminated the real cost escalation from the land and building non system capital expenditure category. The *AER*'s Draft Decision results in forecast land and buildings non system capital expenditure over the next *regulatory control period* being approximately $5 million below the anticipated expenditure in the current *regulatory control period*. Country Energy does not believe that this is a sustainable position, specifically given the significant number of additional resources required to deliver the expanded capital expenditure and operating expenditure programs.

Country Energy provided Wilson Cook with the proposed land and buildings capital works program required to support the network investment forecast during the next *regulatory control period*. The works program detailed the business as usual capital expenditure program for non system land and buildings. To estimate the additional capital expenditure required for the expanded resource requirement, an estimate was calculated using an average cost per extra resource and then added to the business as usual program to give the total land and buildings capital expenditure forecast for the next *regulatory control period*.

In light of the *AER*'s decision to reduce the forecast capital expenditure by $20.8 million due to double counting between business as usual capital expenditure and the additional property required as a result of the necessary increase in resources, Country Energy has reviewed its non-system land and building capital expenditure. Following this review, Country Energy identified some projects listed in the business as usual program to support business growth, but not to the extent of the $20.8 million reduction included in the *AER*'s Draft Decision.

Of the eleven field service centre projects contained in the business as usual program for construction in the next *regulatory control period*, only two are for new locations to accommodate business growth. In terms of resource numbers, Country Energy has found that approximately 27.4 per cent of the total additional resources required over the next *regulatory control period* have already been accounted for in the business as usual non system land and buildings capital expenditure program.

The total forecast non system land and buildings capital expenditure relating to the additional resource requirement is $41.7 million. Therefore, rather than reducing the forecast costs for additional resources by the 50 per cent included in the *AER*'s Draft Decision, Country Energy has included in its revised forecast non system land and buildings capital expenditure a reduction of 27.4 per cent or $11.4 million.

5.4 Capital Expenditure Cost Escalators

The *AER*'s Draft Decision recognised the necessity to determine a price index that encompasses more than CPI when escalating the relevant inputs employed in capital investment activities. However, the *AER*'s Draft Decision also disregarded some cost escalators, amended the methodology in other areas and updated Country Energy's proposal for the latest available data.

Country has implemented some aspects of the *AER*'s decision on capital expenditure cost escalators including:

- Using a value of zero for producers margin; and
- Reviewed and revised down the escalators for wood poles with reference to information provided by suppliers.

However, Country Energy does not accept the *AER*'s Draft Decision on other cost escalators or methodologies employed. Country Energy has maintained the methodology used in its June 2008 *regulatory proposal* (apart from the instances noted above), updated for the latest data available at the time of the submission of this revised *regulatory proposal*. The expenditure forecasts presented in this revised *regulatory proposal* are in real terms including market expectations of real wage and material/equipment cost increases based on an updated report from CEG, attached as appendix D. The CEG report outlines the reasons for Country Energy's approach and addresses some of the concerns Country Energy has with the *AER*'s Draft Decision.

5.5 Real Cost Escalation for Non-System Capital Expenditure

Country Energy does not believe that the *AER*'s draft decision to remove the application of real cost escalators is appropriate. The application of this escalator is similar in nature to the asset growth escalator applied to operating expenditure in that it is a global escalator that is applied equally to all non-system asset categories. The global escalator is calculated consistent with the system asset escalators by using a weighted average of all asset component and category escalators, and then applied globally to total capital expenditure.

This approach is also consistent with the *AER*'s draft decision not to compensate Country Energy for all input costs at a fine level of detail, instead applying single global escalators to relevant expenditures. Country Energy's non-system capital expenditure real cost escalator achieves exactly the same result by weighting each asset category's contribution to the total non-system capital expenditure and multiplying it by the relevant escalator recommended by CEG (refer to appendix D). Therefore, the global weighted average non-system capital expenditure real cost escalator reflects the contributions that components including land and labour make to the total non-system capital expenditure forecasts.

The alternative approach would be to apply individual cost escalation at the non-system asset category level but the end result in terms of total real cost escalation would be exactly the same. Country Energy believes its approach is consistent with methodology applied and approved to system assets and much simpler. Country Energy has therefore not implemented the *AER*'s draft decision on this aspect, and has maintained the approach adopted in the original June 2008 *regulatory proposal*.

5.6 Actual Capital Expenditure for 2007-08

It was not possible to have actual 2007-08 data for inclusion in Country Energy's *regulatory proposal* when it was submitted in June 2008, therefore all 2007-08 data was based on a forecast. Country Energy's revised *regulatory proposal* and attached PTRM and RFM include updated 2007-08 capital expenditure based on audited actual data.

Table 9 below summarises the actual 2007-08 capital expenditure compared to the estimate used in Country Energy's *regulatory proposal* submitted in June 2008. As can be seen from the table, the actual capital expenditure was reasonably consistent with the estimate and has not resulted in any changes to the outer year capital expenditure forecasts that were included in Country Energy's June 2008 *regulatory proposal*.

$ M (nominal)	2007-08
Actual	490
Estimate June 2008	474

Table 9 - Actual 2007-08 capital Expenditure for standard control services

5.7 Equity Raising Costs

In its draft decision, the *AER* rejected Country Energy's proposed methodology for calculating equity raising costs and also removed equity raising costs from operating expenditure and added the calculated value to the regulatory asset base.

Country Energy engaged CEG to review the *AER*s draft decision on equity raising costs and provide additional supporting evidence for the calculation of these costs. Country Energy maintains that the *AER* should consider the inclusion of the equity raising costs recommended by CEG. Country Energy maintains its current position on the cost of raising equity and provides supporting information showing the need for regulators to take into account these additional costs in the independent CEG report included at appendix C.

The projected equity raising costs added to the regulatory asset base for the next *regulatory control period* are $54.9 million.

5.8 Summary of Revised Capital Expenditure Forecasts for the Next *Regulatory control period*

Country Energy's revised forecast of capital expenditure relating to standard control services for the next *regulatory control period*, assuming a base growth scenario, is summarised in * Numbers may not add due to rounding.

Table 10 below. Country Energy has forecast productivity gains in resourcing its internal programs of work in accordance with Country Energy's resourcing plan.

$M (2008-09) *	2009-10	2010-11	2011-12	2012-13	2013-14
System related					
Asset renewal/replacement	139	158	170	177	184
Growth	251	281	299	308	316
Reliability and quality of service enhancement	167	183	190	191	192
Environmental, safety and statutory obligations	36	40	43	44	45
LESS: Productivity savings	(3)	(7)	(7)	(7)	(8)
Total system capital expenditure	**589**	**656**	**695**	**712**	**729**
Non system related					
Information technology	61	62	52	40	41
Furniture, fittings, plant & equipment	11	10	9	10	9
Motor vehicles	61	52	47	38	39
Land and buildings	25	19	17	17	17
Other non system assets	5	5	5	6	6
Total non-system capital expenditure	**164**	**148**	**131**	**111**	**112**
TOTAL CAPITAL EXPENDITURE	**753**	**804**	**826**	**823**	**841**

* Numbers may not add due to rounding.

Table 10 - Forecast capital expenditure for standard control services

Directors' Certification Statement

In accordance with Rule S6.1.1(5) of the transitional *Rules*, this revised *regulatory proposal* must contain a certification by the Directors of Country Energy of the key assumptions underlying the capital expenditure forecasts. The Directors' certification statement is attached at appendix E.

Depreciation

6 Depreciation

6.1 Overview

Chapter 6 of Country Energy's *regulatory proposal*, dated June 2008, presented the forecast regulatory and tax depreciation for standard control service assets over the next *regulatory control period*.

Country Energy did not propose any changes to asset lives for regulatory purposes from those used in the IPART determination. Tax depreciation was calculated in accordance with tax law on a straight line basis.

In its Draft Decision, the *AER*:

a) Accepted Country Energy's proposed standard asset lives, consistent with those previously approved by IPART

b) Accepted updated asset remaining lives that were revised upon a request from the *AER* subsequent to submission of Country Energy's *regulatory proposal*, to account for reallocation of the work in progress value across other existing asset classes;

c) Accepted Country Energy's proposed standard tax lives and remaining lives as appropriate after minor revisions to account for reallocation of the work in progress value across other existing asset classes

d) Recalculated regulatory and tax depreciation based on the above decisions and also to correct for an error where the correct asset lives stated in Country Energy's *regulatory proposal* were incorrectly entered in the post tax revenue model.

Country Energy has implemented all aspects of the *AER*'s Draft Decision in relation to both regulatory and tax depreciation. Country Energy has also updated actual regulatory depreciation for 2007-08 based on actual capital expenditure, and revised regulatory and tax depreciation for the next *regulatory control period* as a result of all amendments described in this revised proposal.

The remainder of this chapter is structured as follows:

- Section 6.2 presents actual regulatory depreciation for the 2007-08 year, and
- Section 6.3 presents revised depreciation forecasts for the next *regulatory control period*.

6.2 Actual Regulatory Depreciation for the Current *Regulatory control period*

The Regulatory Asset Base (RAB) roll forward methodology requires regulatory depreciation to be recalculated on the actual capital expenditure incurred or forecast capital expenditure over the current *regulatory control period*. In accordance with the transitional *Rules*, the actual depreciation must be calculated in accordance with the rates and methods allowed in the *distribution determination* for that period.

Table 11 below shows the recalculated regulatory depreciation for the current *regulatory control period* compared to the allowances provided in the IPART determination The only amendments from the June 2008 *regulatory proposal* are revised figures for 2007-08 and 2008-09 due to updated actual 2007-08 capital expenditure.

$M (nominal)	2004-05	2005-06	2006-07	2007-08	2008-09
Allowed Depreciation	141	148	155	162	168
Actual Depreciation	134	156	173	199	227

Table 11 - Regulatory depreciation for the current *regulatory control period*

6.3 Forecast Depreciation for the Next *Regulatory control period*

In reviewing Country Energy's June 2008 *regulatory proposal*, the *AER* found an inconsistency in the regulatory asset lives listed in the *regulatory proposal* compared to those entered into the PTRM, and requested a reallocation of the work in progress (WIP) asset category for both regulatory and tax purposes. Country Energy agreed with the *AER* that there was a discrepancy and subsequently sent corrected asset lives including reallocated WIP to the *AER*. The *AER* accepted these corrections and reallocations in its Draft Decision.

Effective asset lives

Country Energy has now corrected the PTRM and calculated regulatory depreciation consistent with the average effective lives included in the June 2008 *regulatory proposal* and repeated them in Table 12 below.

Asset Category	Average Effective Life
Sub-transmission lines and cables	55
Distribution lines and cables	54
Substations	40
Distribution transformers	46
Low voltage lines and cables	51
Customer metering and load control	26
Communications	7
Land and easements	-
Other system assets	18
Information Technology	5
Furniture, fittings, plant and equipment	13
Motor vehicles	8
Land and buildings	50
Other non-system assets	15

Table 12 - Effective lives by asset class

The derivation of depreciation at a more aggregated level, using a gross weighted average age profile, provides an equally accurate but simplified assessment. The weighted average effective life of Country Energy's system assets is estimated at 45 years, and for non system assets and the weighted average effective life is estimated at 9 years.

Remaining lives

Country Energy has now corrected the PTRM and calculated regulatory depreciation consistent with the average remaining lives in Table 13 below. The average remaining lives are considered to be an accurate reflection of actual average ages and considered to be reliable for the purposes of determining regulatory depreciation.

Asset Category	Average Remaining Life
Sub-transmission lines and cables	25
Distribution lines and cables	37
Substations	22
Distribution transformers	21
Low voltage lines and cables	22
Customer metering and load control	6
Communications	2
Land and easements	-
Other system assets	9
Information Technology	2
Furniture, fittings, plant and equipment	10
Motor vehicles	5
Land and buildings	48
Other non-system assets	1

Table 13 - Average remaining lives of various asset classes

As mentioned above, the establishment of depreciation at a more aggregated level, using a gross weighted average age profile provides an equally accurate and simple assessment. The weighted average remaining life of system assets is estimated at 23 years and for non system assets, the weighted average remaining life is estimated at 5 years.

Forecast regulatory depreciation for the next *regulatory control period*

From the starting asset values and asset lives at July 2009, Country Energy has calculated the regulatory depreciation for each year of the next *regulatory control period,* as illustrated in Table 14 below.

$M (nominal)	2009-10	2010-11	2011-12	2012-13	2013-14
Forecast Regulatory Depreciation	152	175	140	162	183

Table 14 - Forecast regulatory depreciation

Forecast tax depreciation for the next *regulatory control period*

In order to move from IPART's pre tax framework to the *AER*'s post tax framework, it is necessary for Country Energy to calculate tax depreciation for the next *regulatory control period*. The PTRM provides more information on tax depreciation schedules.

For the purpose of estimating the cost of corporate income tax, Country Energy has calculated tax depreciation in accordance with tax law on a straight line basis. Table 15 shows the forecast tax depreciation schedule for the next *regulatory control period*.

$M (nominal)	2009-10	2010-11	2011-12	2012-13	2013-14
Forecast Tax Depreciation	163	185	223	243	274

Table 15 - Forecast tax depreciation

Value of the Opening Regulatory Asset Base

7 Value of the Opening Regulatory Asset Base

7.1 Overview

The value of Country Energy's Regulatory Asset Base (RAB) prescribed in clause S6.2.1(c)(1) of the transitional *Rules* is $2,440 million as at 1 July 2004. Chapter 7 of Country Energy's *regulatory proposal*, dated June 2008, set out the roll forward methodology applied in establishing the proposed opening RAB as at 1 July 2009, and the roll forward of this value to 30 June 2014.

The *AER* in its Draft Decision:

a) Determined adjustments to the RAB of $9 million for the difference between actual and forecast capital expenditure in 2003-04 and the associated return on that difference;

b) Accepted adjustments to the RAB of $34 million for asset disposals over the current *regulatory control period*;

c) Determined adjustments to the RAB of $467 million for depreciation based on actual capital expenditure;

d) Accepted adjustments to the RAB for deferred depreciation allowed for in the *2004 IPART determination*;

e) Rejected proposed increase to the RAB of $296 million for assets omitted from the previous RAB valuation;

f) Included $2,206 million of capital expenditure incurred and forecast during the current *regulatory control period* in the RAB; and

g) Indexed the opening RAB for actual inflation using the Consumer Price Index (CPI), making a minor adjustment to align inflation inputs with their corresponding regulatory years.

Country Energy has implemented the majority of the components from the *AER*'s Draft Decision listed above in relation to the RAB. The exception is the inclusion of actual 2007-08 data in the calculation of the opening RAB.

The remainder of this chapter is structured as follows:

- Section 7.2 presents an updated opening RAB as at 1 July 2009 for the inclusion of actual 2007-08 capital expenditure from Chapter 5, and
- Section 7.3 details the revised roll forward of the RAB from 1 July 2009 to 30 June 2014, using updated capex and depreciation from this revised proposal.

7.2 Roll Forward of the RAB from 1 July 2004 to 30 June 2009

The roll forward calculation over the current *regulatory control period* from 1 July 2004 to 30 June 2009 is depicted in Table 16 below. The table presents the aggregation of capital expenditure, regulatory depreciation, and disposals for all asset classes. The closing RAB at 30 June 2009 for Country Energy is $4,262 million.

$M (nominal)	2004-05	2005-06	2006-07	2007-08	2008-09
Opening RAB	2,439	2,638	2,920	3,324	3,740
Plus all capital expenditure	284	364	460	512	604
Plus deferred depreciation	-	10	21	33	48
Less actual depreciation	134	156	173	199	227
Less asset disposals	7	7	7	8	7
Plus indexation	57	70	103	78	112
Less difference between actual and forecast capital expenditure	-	-	-	-	9
Closing RAB	2,638	2,920	3,324	3,740	4,262

Table 16 - Roll forward of the RAB to 30 June 2009

7.3 Roll Forward of the RAB from 1 July 2009 to 30 June 2014

The projected RAB (and the components thereof) at the end of each year over the next *regulatory control period* is summarised in Table 17 below.

$M (nominal)	2009-10	2010-11	2011-12	2012-13	2013-14
Opening RAB	4,262	4,960	5,651	6,424	7,195
Plus all capital expenditure	859	876	922	943	988
Less actual depreciation	261	302	284	326	367
Less asset disposals	9	9	9	9	10
Plus indexation	109	126	144	164	183
Closing RAB	4,960	5,651	6,424	7,195	7,990

Table 17 - Roll forward of the RAB from 1 July 2009 to 30 June 2014

Weighted Average Cost of Capital

8 Weighted Average Cost of Capital

8.1 Overview

Chapter 8 of Country Energy's *regulatory proposal*, dated June 2008, described the methodology followed to determine the weighted average cost of capital (WACC) and the cost of tax.

In its Draft Decision, the *AER*:

a) Determined a nominal vanilla WACC of 9.72 per cent, which is slightly less than that proposed by Country Energy; and

b) Advised that it 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.

Country Energy has implemented the *AER*'s Draft Decision in most respects, except for the averaging period and the expected inflation rate. This has subsequent flow on effects to the cost of tax discussed in this chapter, and building blocks used in the PTRM discussed in chapter 10.

The remainder of this chapter is structured as follows:

- Section 8.2 discusses the averaging period used to calculate the risk free rate and debt risk premium
- Section 8.3 presents the expected inflation rate used by Country Energy
- Section 8.4 presents the WACC used to determine the return on capital component in this revised proposal, and
- Section 8.5 details the establishment of the tax allowance calculated for inclusion in this revised proposal.

8.2 Averaging Period

The *AER* in its Draft Decision disagreed with the averaging period proposed by Country Energy on the basis that the period proposed was too far removed from the final determination date.

While, Country Energy understands the *AER*'s reasons for selecting an averaging period as close to the final determination date as possible, this approach can only be considered appropriate under normal economic circumstances. Country Energy believes that a revised averaging period must be adopted that does not contain observations encompassing the current global financial crisis.

Given the volatility in the current financial markets resulting from the most severe financial crisis since the great depression, yield rates for Commonwealth Government bonds with a maturity of 10 years have hit unprecedented low levels while risk premiums for investing in equity have moved to historically high levels. This has become significantly prevalent since Fanny Mae and Freddy Mac were placed into conservatorship by the US Treasury. This event has been a major turning point for the significant deterioration of the bond markets during the financial crisis. In addition, the accepted investor risk horizon has shortened significantly since this time as a lack of investor confidence and liquidity in the corporate debt markets has seen longer-term debt issuance almost entirely dry up. Furthermore, the majority of corporate bonds are being issued for shorter periods in the 1 year and 3 to 5 year range.

There is considerable regulatory precedent that supports avoiding selecting averaging periods during times of financial crisis. Country Energy cites the following examples as reported in appendix G:

- The ACCC made an adjustment to the averaging period used in the 2002 Powerlink decision in order to exclude the impact of the events of September 11 which were pushing bond prices up (and yields down). The averaging period was moved to end on 11 September 2001 rather than ending on the date of the decision.
- The ESCV made an adjustment to the averaging period used in 2005 when it determined a large proportion of the relevant CGS market was coming to maturity resulting in a shortage of supply of government bonds producing an increase in bond prices and a downward bias in yields. The averaging period was moved to end in July 2005 rather than ending in August 2005.
- There are a number of other examples in the UK and the US that provide precedents for excluding abnormal market events when selecting averaging periods.

Country Energy believes calculating the risk free rate and debt risk premiums using an averaging period of 10 year government bonds where insufficient bonds are being issued and volatility has been markedly skewed, provides an inappropriate and inaccurate estimate of the true cost of raising debt and equity.

Country Energy considers there is ample precedent to enable the *AER* to select a period prior to the global financial crisis. Under Rule S6.1.3(8) Country Energy must nominate the commencement and length of the averaging period for observing the nominal risk free rate. Country Energy proposes to adopt CEG's recommendation on the proposed averaging period for the nominal risk free rate and debt risk premium and the start of the averaging period to occur prior to the event of Fanny Mae and Freddy Mac being placed into conservatorship (refer to appendix G).

8.3 Expected Inflation Rate

In its Draft Decision:

> "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."

Given the *AER* will revise the expected inflation rate in its final determination, the benefits of updating the inflation forecast is limited. Therefore, Country Energy has implemented the 2.55 per cent per annum inflation forecast as advised in the *AER*'s Draft Decision. However, Country Energy does have some concerns with the *AER*'s proposed methodology that it believes should be reflected in the final determination, as described below.

The current market volatility and the global financial crisis raises concerns for accurately determining the expected inflation rate. As mentioned previously, Country Energy has engaged CEG to review the effects of the global financial crisis on WACC components with particular emphasis on the averaging period and the expected inflation rate.

Since the last determination, the *AER* has changed its inflation forecast methodology from using the break-even inflation from the CGS market which was deemed to be overstating expected inflation, to adopting the RBA forecasts. As mentioned in appendix G this methodology provides an expected inflation forecast of 2.63 per cent as at December 2008. Inherent problems have appeared with using the current *AER* methodology to calculate the expected inflation rate at the determination date using bond rates during the global financial crisis. The relative bias in CGS bonds appears to have reversed as a result of the high liquidity premiums being paid during the global financial crisis resulting in the *AER*'s current methodology making the real risk free rate less accurate.

In particular, there are problems with both the nominal and indexed CGS 10 year bonds post September 2008 with the volatility and lack of liquidity adversely impacting the accuracy of the calculation of break-even and expected inflation rates and hence the real risk free rate. Between September 2008 and 2 January 2009 the break-even inflation rate has moved dramatically from a high of 3.4 per cent in September to 1.43 per cent in January with the latter being some 45 per cent lower that the 10 year average expected inflation rate. Selecting an averaging period prior to this time that is not affected by the global financial crisis (e.g. when the break even rate is not less than the actually accepted inflation rate) and using the RBA inflation forecast consistent with the averaging period should result in a less biased estimate of the cost of equity.

Country Energy recommends the *AER* considers the supporting information provided in appendix G and selects the averaging period proposed by CEG with which to calculate the expected inflation rate. Country Energy considers this period to be the closest period to the date of the final determination available that excludes the biased 10 year CGS bond data.

8.4 Weighted Average Cost of Capital

Based on the above, Country Energy has calculated a post tax WACC of 10.15 per cent in accordance with the requirements of the transitional *Rules*.

The table below provides a summary of the parameter values that have been adopted in our calculation of WACC and resulting WACC estimates.

Parameter	Recommended value (per cent)
Nominal risk free rate	5.82
Inflation rate	2.55
Debt risk premium	3.22
Equity beta	1.0
Market risk premium	6.0
Equity proportion	40
Debt proportion	60
Post-tax nominal vanilla WACC	**10.15**

Table 18 - Pre-tax Real WACC Parameter Estimates

8.5 Cost of tax

Country Energy has calculated the net tax allowance for the next *regulatory control period* and it is summarised in * Numbers may not add due to rounding.
Table 19 below. Country Energy has calculated this tax allowance using the *AER*'s PTRM and the tax depreciation allowances discussed in Chapter 6.

$M (nominal) *	2009-10	2010-11	2011-12	2012-13	2013-14
Tax payable	91	104	91	107	118
Less value of imputation credits	(45)	(52)	(46)	(54)	(59)
Net tax allowance	45	52	46	54	59

* Numbers may not add due to rounding.

Table 19 - Tax allowance

Other Economic Regulatory Arrangements

9 Other Economic Regulatory Arrangements

9.1 Overview

Chapter 9 of Country Energy's *regulatory proposal*, dated June 2008, provided Country Energy's views on a range of economic regulatory arrangements that had not been covered elsewhere in that *regulatory proposal*. Country Energy maintains this approach for this revised *regulatory proposal*, with the exception of miscellaneous and monopoly services (which have been addressed in Chapter 3).

The remainder of this chapter is structured as follows:

- Section 9.2 details Country Energy's proposed pass through event framework
- Section 9.3 discusses the framework for the demand management incentives
- Section 9.4 provides Country Energy's views on the efficiency benefit sharing scheme (EBSS)
- Section 9.5 discusses the service target performance incentive scheme (STPIS), and
- Section 9.6 details transitional issues.

9.2 Pass Through Arrangements

Country Energy's *regulatory proposal* proposed seven nominated pass through events for the *AER* to include in its distribution determination.

In its Draft Decision, the *AER*:

a) Did not accept that the introduction of smart meters as a nominated pass through event, but stated it is likely to be a regulatory change event;

b) Did not accept intelligent network investments as a separate nominated pass through event, but will consider them as part of an application for a pass through adjustment for the introduction of smart meters as a regulatory change event;

c) Did not accept the following events that potentially could be classified as self insurance events:

   a. Asbestos and gradual pollution- due to the belief that a DNSP has some control over the event and does not consider that these incidents that occurred in the past should be passed on to current or future users

   b. Climate change (introduction of an emissions trading scheme) and retailer of last resort (RoLR) – stating that these are likely to be a regulatory change event

c. Electric and magnetic field (EMF) – given that third party claims for EMF events are insurable, third party claims are not accepted as a pass through event. In relation to any obligations placed on the business which may have a material impact on operating costs, 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

d. Business continuity –which was not specifically addressed in the Draft Decision

e. Workers compensation premium –due to fears it would undermine incentives for minimising costs and improving Occupational Health and Safety performance. Nevertheless, the *AER* will consider any specific events provided that Country Energy can demonstrate that the criteria set out in section 15.6.1 of the Draft Decision have been met;

d) Did not accept changes in risk assessment costs due to court cases and other legal obligations as a nominated pass through event due to concerns with the broad nature of the proposed pass through event. The *AER* believes Country Energy has some control over expenditure for such an event and considers the most appropriate time to pass any cost changes through is at a regulatory reset;

e) Accepted change to obligations, structure and costs due to outcomes of retail reform projects as a nominated pass through event;

f) Did not accept input cost variations as a pass through event due to fears it would undermine incentives for minimising costs. Nevertheless the *AER* will consider any specific events provided that Country Energy can demonstrate that the criteria set out in section 15.6.1 of the Draft Decision have been met;

g) Did not accept network support payments as a nominated pass through event, as the *AER* considers it would effectively result in Country Energy being overcompensated; and

h) Advised that the risk of the cost impact for acts of extortion or bomb threats pertaining to a terrorist related event are covered under the NER as a pass through event.

Country Energy has implemented the majority of the *AER*'s Draft Decision described above with the exception of the following:

- Changes in risk assessment costs due to court cases and other legal obligations
- Events deemed to be regulatory change events, specifically, the introduction of smart meters, RoLR, and the introduction of an emissions trading scheme (climate change)
- Electric and magnetic field uninsurable event.
- Define a specific pass through materiality threshold for DNSP events and in particular a lower materiality threshold for pass through events triggered by asymmetric risks.
- Inclusion of magnitude 6 earthquakes as a pass through event
- Inclusion of an insurance pass through event

Sheather case

Country Energy's *regulatory proposal* of June 2008 included this legal decision as a nominated pass through event. The *AER*'s Draft Decision rejected this treatment, and stated that the most appropriate time for Country Energy to seek to pass through any cost changes is at the time of a regulatory reset. Therefore, given that it is expected that costs will start being incurred by Country Energy during the next *regulatory control period*, a forecast level of operating expenditure has been developed by Country Energy for inclusion and is detailed within section 4.5 of this revised *regulatory proposal*.

Events deemed to be regulatory change events

The *AER*'s draft determination in section 15.6.3 considers a number of the proposed pass through events as being likely *regulatory change events*. Country Energy draws particular attention to the following events:

- The introduction of smart meters,
- Retailer of last resort (RoLR), and
- The introduction of an emissions trading scheme (climate change).

The *AER* further states it "considers that the defined events contained in the transitional chapter 6 *Rules* were designed to cover these types of events". Country Energy requests that the *AER* positively confirm in its Final Determination that if legislated for, smart meters, RoLR and/or the introduction of an emissions trading scheme will constitute a defined event. As currently written in the Draft Decision there is no guarantee that the *AER* will recognise smart meters, RoLR and/or the introduction of an emissions trading scheme as regulatory change events in order for Country Energy to pass through the costs associated with the implementation of any such schemes.

In the absence of the *AER* recognising these events in the Final Determination as defined events with certainty (however, appropriately qualified), or as nominated events Country Energy may be precluded from recovering costs for these events, which in inconsistent with the regulatory objectives of the transitional *Rules* and the *Law*.

The *Law* section 7A(2)(b) states that a "regulated network service provider should be proved with a reasonable opportunity to recover at least the efficient costs the operator incurs in complying with a regulatory obligation or requirement or making a regulatory payment". Should the above events be mandated, Country Energy should be guaranteed the opportunity to recover for an event undertaken by an efficient and prudent operator in accordance with Country Energy's regulatory requirements.

Country Energy again notes that the *AER* is yet to release a guideline on the materiality threshold for pass through events and submits that regardless of the final threshold used by the *AER* in its Final Determination, it should be limited to the defined events contained in the transitional chapter 6 *Rules* and should not apply to nominated pass through events.

Electric and magnetic field uninsurable event

Country Energy's *regulatory proposal* supported the inclusion of a pass through for the introduction of the Australian Radiation Protection and Nuclear Safety Agency (ARPANSA) draft standard and for operational costs relating to electromagnetic events. Country Energy informed the *AER* that it has insurance cover for third party claims through its liability insurance program.

In its Draft Decision, the *AER*:

a) Noted that the introduction of the ARPANSA draft standard implementation event is covered by the policy intent of the NER and should be considered as a regulatory change event; and

b) Given that third party claims relating to EMF events are insurable, the *AER* does not accept third party claims as a pass through event.

Country Energy accepts that the implementation of the draft ARPANSA standard could be considered a regulatory change event under the NER.

In relation to third party claims relating to EMF events, Country Energy advises that its insurance coverage for EMF events only covers physical damage to third party property. The insurance coverage excludes claims for compensation for incidents like class actions from neighbourhoods claiming devaluation of property values or an inability to sell their property as a result of a EMF event in the area.

Therefore, Country Energy proposes that uninsurable third party claims be included as a pass through event.

Materiality thresholds for DNSP pass through events

The NER currently only provides a clear materiality threshold for TNSP pass through events, with this threshold set at greater than 1 per cent of Maximum Allowed Revenue (MAR). Country Energy has previously sort guidance from both the *AEMC* and the *AER* on a definition of "materiality" in relation to a materiality threshold for DNSP pass through events. At this stage no definition has been forthcoming, perpetuating uncertainty amongst DNSPs of the trigger for a pass through event. Country Energy believes the materiality threshold should be defined in the *AER*'s final determination. A reasonable starting point would be to align it with the materiality threshold for a TNSP pass through event.

In addition, the *AER* advised in the Draft Decision that the self insurance cost impact for acts of extortion or bomb threats pertaining to a terrorist related event are covered under the NER as a pass through event and as such denied Country Energy proposed self insurance premium for this risk type. Country Energy believes that there is the potential for a pass through application resulting from a terrorist related risk resulting in negative financial repercussions should the event not be large enough to meet the materiality threshold test. Although Country Energy considers the impact of terrorist events are most efficiently covered through self insurance, it acknowledges the provisions in the NER for a terrorism event pass through and requests the *AER* consider setting a lower materiality threshold for pass through events triggered by asymmetric risks like terrorist events to ensure DNSP's can be fully compensated for such events.

Magnitude 6 earthquakes

The *AER* advised in the Draft Decision that the self insurance cost impact relating to magnitude 6 earthquakes has no history of occurrence in NSW an as such should not be covered by self insurance as discussed in section 4.6 of this submission. Country Energy considers that there is a genuine risk of a magnitude 6 earthquake occurring in the future although the likelihood is quite remote. The financial impact on a DNSP should a magnitude 6 earthquake occur is substantial enough to warrant the inclusion as a pass through event if the *AER* maintains its approach of denying a self insurance allowance for the event.

Country Energy proposes to include earthquakes greater than magnitude 5 as pass through events if the event type is excluded as a self insurable event to ensure adequate DNSP compensation can be maintained.

Insurance event

Country Energy has identified there is potential for substantial changes to the value of insurance premiums, or insurance becomes unavailable due to a claim or number of claims being made by Country Energy over the next *regulatory period.*

Country Energy proposes including an insurance event as a nominated pass through event. The following definition of an insurance event has been developed to be consistent with the definition in chapter 10 of the NER currently applying to TNSPs only.

An insurance event is an event for which the risk of its occurrence is the subject of insurance taken out by or for a DNSP, for which an allowance is provided in the total revenue requirements for the DNSP and in respect of which:

a) the cost of the premium paid or required to be paid by the DNSP in the regulatory year in which the cost of the premium changes is higher or lower than the premium that is provided for in the revenue requirement for the DNSP for that regulatory year by an amount of more than the materiality threshold applying to the DNSP for a pass through event for that regulatory year;

b) the risk eventuates and, as a consequence, the DNSP incurs or will incur all or part of a deductible where the amount so incurred or to be so incurred in a regulatory year is higher or lower than the allowance for the deductible (if any) that is provided for in the revenue requirements for the DNSP for that regulatory year by an amount of more than the materiality threshold applying to the DNSP for a pass through event for that regulatory year;

c) insurance becomes unavailable to the DNSP; or

d) insurance becomes available to the DNSP on terms materially different to those existing as at the time the regulatory determination was made (other than as a result of any act or omission of the DNSP which is inconsistent with good electricity industry practice).

Country Energy proposes including an insurance event meeting the definition above as a nominated pass through event.

9.3 Demand management incentives

Country Energy's *regulatory proposal* supported the continuation of the D-factor scheme and the introduction of a demand management innovation allowance (DMIA).

In its Draft Decision, the *AER*:

a) Maintained its decision to apply the D-factor scheme to Country Energy during the next *regulatory control period* in the form applied by IPART over the current *regulatory control period*; and

b) Retained the DMIA but has replaced it with a revised DMIA issued with the Draft Decision. The revised DMIA is subject to agreement by Country Energy through written confirmation to the *AER*.

Country Energy understands that the revised DMIA will take the form of an allowance which comprises the following components:

- An ex ante DMIA in the form of additional revenue of $600,000 per annum at the commencement of each regulatory year for the period 2009-10 to 2013-14.
- The DMIA is able to be spent at any time during the *regulatory control period*.

- Demand management expenditure will be subject to an ex-post assessment of expenditure against the DMIA criteria at the end of each year of the *regulatory control period*.
- Country Energy will be required to submit an annual public report on the outcomes of the expenditure which will be published by the *AER*.
- A final carry over amount will be adjusted to allowed revenue in the second regulatory year of the subsequent *regulatory control period*.
- Recovery of foregone revenue resulting in the reduction in the quantity of electricity sold which is directly attributable to the implementation of a non-tariff demand management program approved under part A.
- Approved forgone revenue will be provided in the second regulatory year as an addition to the innovation allowance adjustment in the regulatory year.

Country Energy believes the *AER*'s Draft Decision regarding the revised DMIA framework improves the original version. Country Energy supports the *AER* proposal that the allowance takes the form of an ex-ante allowance at the commencement of each *regulatory control period*. There is a level of risk transferred to the DNSP with an ex-post assessment of the expenditure and this should be mitigated through clear and objective qualification critieria. The revised scope of the DMIA criteria in section 3.1.3 of the *AER*'s Demand Management Incentive Scheme for the ACT and NSW distribution determination, published in November 2008 largely addresses that risk.

However, Country Energy notes that the allowance of $600,000 per annum has been maintained and remains modest as highlighted by the extensive discussions during the consultation phase of development of the NSW/ACT, QLD/SA and VIC schemes.

Country Energy believes that the DMIA needs to be increased in order to promote meaningful demand management projects. Country Energy believes a fair and reasonable DMIA could be linked to the annual revenue requirements calculated as part of the final determination.

For example, given that the DMIA is an immature scheme, Country Energy suggests an amount of between 1 and 5 per cent of annual revenue requirements would be a fair and reasonable amount for each DNSP in the next *regulatory control period*. This would allow time for proper evaluation of the scheme, but would provide a much more practical level of funding.

9.4 Efficiency Benefit Sharing Scheme

Country Energy's *regulatory proposal* supported the exclusions nominated by the *AER* in their EBSS in February 2008, and welcomed the opportunity to work with the *AER* on the operational framework of the EBSS that will apply in the next *regulatory control period*.

In its Draft Decision, the *AER*:

a) Confirmed that it will apply the EBSS released in February 2008 to Country Energy for the next *regulatory control period*;

b) Will not adjust the EBSS for a change in demand growth for Country Energy over the next *regulatory control period*; and

c) Will exclude the following operating expenditure cost categories from the operation of the EBSS:

- debt raising costs
- self insurance costs
- insurance costs
- superannuation costs relating to defined benefit and retirement schemes
- non-network alternatives
- cost pass through events

Country Energy acknowledges the *AER*'s commitment to establishing the EBSS to apply to the NSW DNSPs from 1 July 2009 and at this stage, Country Energy is not seeking to add further exclusions to the scheme. Country Energy looks forward to working with the AER on establishing the framework for the timing, content and verification of EBSS claims.

9.5 Service Target Performance Incentive Scheme

Country Energy's *regulatory proposal* supported the *AER*'s proposed information collection and monitoring, supplemented by a paper trial based on the national distribution STPIS.

In its Draft Decision, the *AER*:

a) Confirmed it will collect and monitor service performance data during the next *regulatory control period*;

b) Confirmed revenue will not be placed at risk under the data collection process during the next *regulatory control period*;

c) Has aligned data reporting requirements with the requirements of the national STPIS; and

d) Expects Country Energy to implement measures to achieve full compliance with the national distribution STPIS as soon as practical so that data from the 2009-10 financial year can be assessed by December 2010.

Country Energy acknowledges the *AER*'s intent to collect and monitor service performance data over the next *regulatory control period* in accordance with clause 6.6.2(h) of the transitional chapter 6 *Rules* and its confirmation that revenue will not be placed at risk under the data collection process during this period. Country Energy is concerned about its ability to have systems implemented and tested by December 2009. While every endeavour will be made to have our new interruption recording software commissioned as soon as possible, the outputs from this system will require robust analysis and confirmation that they accurately reflect customer experiences.

Country Energy confirms its agreement that reporting requirements require alignment to the national distribution STPIS.

As previously communicated to the *AER*, Country Energy is unlikely to be able to provide full MAIFI data for the next *regulatory control period*. Country Energy is 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. To immediately equip all other reclosers would be extremely expensive and can only happen over a longer time period than envisaged in the *AER*'s Draft Decision.

While it is acknowledged that the frequency of interruption measure does not currently apply to Country Energy, it is thought that the definition of this measure requires further clarification. The definition as currently written is unworkable in our distribution area, currently the NSW measure is 4 outages greater than 5 hours duration. The implementation of our new interruption recording software will transition recording outages at a feeder section level to a distribution transformer level. The old and new interruption software do not record outages at a customer level so a degree of inaccuracy will exist within the frequency measure proposed by the *AER*.

Country Energy would welcome further consultation on elements of the proposed reporting templates as proposed by the *AER* for the next *regulatory control period* to ensure full compliance can be achieved. Country Energy wishes to reiterate that by complying with the proposed reporting requirements two sets of data will be published, potentially creating confusion for users.

9.6 Transitional Issues

Country Energy's *regulatory proposal* deducted the amount of the forecast balance of the transmission unders and overs account as at 30 June 2007 from the building block revenue in 2009-10 in the PTRM. Country Energy's *regulatory proposal* also established a tax asset base by reconciling the 30 June 2007 tax assets to the RAB, and then rolling forward to 30 June 2009 utilising forecast capital expenditure for the 2007-08 and 2008-09 years.

In its Draft Decision, the *AER*:

a) Accepted Country Energy's treatment of the remaining balance of the transmission unders and overs account by incorporating it in the PTRM as proposed;

b) Confirmed that Country Energy must maintain a transmission unders and overs account and provide information on the account as part of the annual pricing proposal process; and

c) Accepted Country Energy's opening tax asset base as appropriate and reasonable.

Country Energy has implemented all aspects of the *AER*'s Draft Decision, however the transmission unders and overs account balance used in the PTRM attached to the Draft Decision has been updated to reflect the availability of more accurate data.

The current amount of the transmission unders and overs account used in the PTRM was the closing balance as at 30 June 2007. In this revised proposal and accompanying PTRM, Country Energy has updated this balance to reflect the actual closing balance as at 30 June 2008.

Prior to the *AER* making its final determination, Country Energy will provide a forecast of the transmission unders and overs account balance for 30 June 2009 as further actual data becomes available. The amount included in the PTRM and subsequent annual pricing proposal will then be offset against the balance of the transmission unders and overs account.

Revenue requirements

10 Revenue requirements

10.1 Overview

This chapter details the calculation of Country Energy's annual revenue requirement in accordance with the building block approach outlined in the transitional *Rules* and the *AER*'s PTRM. A summary of the building block components and the unsmoothed and smoothed revenue for each year of the next *regulatory control period* is presented. The building block components and calculated revenues included in Country Energy's *regulatory proposal*, dated June 2008, and in the *AER*'s Draft Decision of November 2008 have been updated with the information presented in this revised proposal. To the extent of any inconsistency between Country Energy's *Regulatory proposal* dated 2 June 2008 and this document, the latter will prevail.

The remainder of this chapter is structured as follows:

- Section 10.2 summarises the key provisions of the transitional *Rules* relating to establishing the annual revenue requirement for each year of the next *regulatory control period*
- Section 10.3 presents each component of the building blocks established in the preceding sections of this *regulatory proposal*
- Section 10.4 details the calculated unsmoothed annual revenue requirement resulting from the building block components
- Section 10.5 presents Country Energy's proposed smoothed revenue requirement for each year of the next *regulatory control period*, including a description of the X factors adopted
- Section 10.6 discusses revenue requirement adjustments that may occur in during the next *regulatory control period*, and

10.2 *National Electricity Rules* Requirements

Clause S6.1.3(6) of the transitional *Rules* specifies that a building block proposal must contain Country Energy's calculation of revenues including all inputs, X factors and explanations of the calculation and inputs used.

Clause 6.5.9 sets out the *AER*'s obligations in establishing X factors for each year of the *regulatory control period*.

10.3 Building Block Components

The building block components and their calculated values are described in the sections below.

Regulatory asset base

Table 20 below reproduces the calculated RAB from chapter 7 for the next *regulatory control period*.

$M (nominal)	2009-10	2010-11	2011-12	2012-13	2013-14
Opening RAB	4,262	4,960	5,651	6,424	7,195
Plus all capital expenditure	859	876	922	943	988
Less actual depreciation	261	302	284	326	367
Less asset disposals	9	9	9	9	10
Plus indexation	109	126	144	164	183
Closing RAB	4,960	5,651	6,424	7,195	7,990

Table 20 - RAB roll forward from 1 July 2009 to 30 June 2014

Return on capital

The return on capital is calculated in accordance with the *AER*'s PTRM. It is calculated by applying the post tax nominal vanilla WACC to the opening RAB for each year of the *regulatory control period*. Table 21 below illustrates this calculation.

$M (nominal)	2009-10	2010-11	2011-12	2012-13	2013-14
Opening RAB	4,262	4,960	5,651	6,424	7,195
Return on Capital	433	504	574	652	731

Table 21 - Return on capital from 1 July 2009 to 30 June 2014

Depreciation

The calculation of regulatory depreciation was carried out in accordance with the *AER*'s PTRM and was detailed in chapter 6 of this revised *regulatory proposal*. Table 22 below summarises the regulatory depreciation calculation.

$M (nominal)	2009-10	2010-11	2011-12	2012-13	2013-14
Regulatory Depreciation	152	175	140	162	183

Table 22 - Regulatory depreciation from 1 July 2009 to 30 June 2014

Operating expenditure

The forecast operating expenditure has been detailed in chapter 4 of this revised *regulatory proposal*. The operating expenditure is summarised in Table 23 below.

$M (2008-09)	2009-10	2010-11	2011-12	2012-13	2013-14
Operating Expenditure	411	432	445	457	467

Table 23 - Operating expenditure from 1 July 2009 to 30 June 2014

Cost of tax

The detailed calculation of the cost of tax was presented in Section 8.5 of this revised *regulatory proposal*. The cost of tax calculation is summarised in

$M (nominal) *	2009-10	2010-11	2011-12	2012-13	2013-14
Tax payable	91	104	91	107	118
Less value of imputation credits	(45)	(52)	(46)	(54)	(59)
Net tax allowance	45	52	46	54	59

* Numbers may not add due to rounding.

Table 24 below.

$M (nominal) *	2009-10	2010-11	2011-12	2012-13	2013-14
Tax payable	91	104	91	107	118
Less value of imputation credits	(45)	(52)	(46)	(54)	(59)
Net tax allowance	45	52	46	54	59

* Numbers may not add due to rounding.

Table 24 - Cost of tax from 1 July 2009 to 30 June 2014

10.4 Unsmoothed Annual Revenue requirement

The unsmoothed annual revenue requirement for each year of the *regulatory control period* is calculated as the sum of the return on capital, depreciation, operating expenditure and cost of tax allowance. The addition of these building block components is depicted in * Numbers may not add due to rounding.

Table 25 below.

$M (nominal) *	2009-10	2010-11	2011-12	2012-13	2013-14
Return on Capital	433	504	574	652	731
Economic Depreciation	152	175	140	162	183
Operating expenditure	421	454	480	505	530
Cost of Tax	45	52	46	54	59
Adjustment for transitional issues	(73)	-	-	-	-
Unsmoothed Revenue Requirement	979	1,185	1,239	1,373	1,503

* Numbers may not add due to rounding.

Table 25 - Unsmoothed annual revenue requirement from 1 July 2009 to 30 June 2014

10.5 Smoothed Annual Revenue requirement

Country Energy has calculated a smoothed revenue requirement by applying X factors in each year of the *regulatory control period* as described in the sections below.

X factors

The revenue requirements resulting from the *AER*'s Draft Decision satisfy clause 6.5.9(b)(3), but in Country Energy's opinion do not fully capture the intent of clause 6.5.9(b)(2). However, in the interests of consistency and comparability with the *AER*'s Draft Decision, Country Energy has based the calculation of the X factors on the AER's methodology.

Table 26 below presents Country Energy's proposed X factors for the next *regulatory control period*.

(real)	2009-10	2010-11	2011-12	2012-13	2013-14
X factor	(24.6%)	(9.5%)	(9.5%)	(9.5%)	(9.5%)

Table 26 - X factors from 1 July 2009 to 30 June 2014

Smoothed annual revenue requirement

Table 27 below presents the smoothed annual revenue requirement resulting from the application of the X factors described above. The *AER*'s PTRM attached to this *regulatory proposal* demonstrates that the smoothed and unsmoothed revenue requirements are equal in net present value terms. The smoothed revenue requirement includes an adjustment in 2009-10 to eliminate the transmission 'overs and unders' account balance as at 30 June 2008. The smoothed revenue for each year is also net of estimated non tariff revenue from miscellaneous and monopoly services.

$M (nominal)	2009-10	2010-11	2011-12	2012-13	2013-14
Smoothed Revenue Requirement	970	1,098	1,242	1,406	1,591

Table 27 - Smoothed annual revenue requirement from 1 July 2009 to 30 June 2014

10.6 Revenue Requirement Adjustments

The revenue requirements calculated in this section will be subject to adjustments during the next *regulatory control period* if any of the following occurs:

- The price change each year will utilise the X factors nominated above and utilising the actual CPI
- Pass though events nominated in Section 9 of this *regulatory proposal* or a pass through event defined in the transitional *Rules*, and
- Demand management incentive scheme programs.

Alternative Control Services

11 Alternative Control Services

11.1 Overview

This chapter responds to chapter 17 of the Australian Energy Regulator's (AER's) Draft Decision on Alternative Control services (street-lighting) for the period 1 July 2009 to 30 June 2014. For clarity, these services relate to the funding and maintenance of street lighting assets owned by Country Energy – the Street Lighting Use of Service (SLUoS) charge.

The remainder of this chapter is structured as follows:

- Section 11.2 summarises Country Energy's key proposals regarding the Draft Decision relative to SLUoS charges
- Section 11.3 summarises the key provisions of the Transitional Rules relating to establishing the annual revenue requirement for each year of the next regulatory control period
- Section 11.4 summarises the Draft Decision
- Section 11.5 sets out three matters on which Country Energy is suggesting enhancements to, or simplification of, the Draft Decision
- Section 11.6 presents Country Energy's proposed Schedules of fixed prices for the first year of the next regulatory control period and for each subsequent year of that period, using the approach set out in the Draft Decision
- Section 11.7 provides information on and explanation of key variables used in the application of the approach set out in the Draft Decision, and
- Section 11.8 discusses other matters – rebates applicable during the transition to cost reflective pricing.

11.2 Summary

As required by 17.8 of the Draft Decision7, Country Energy has developed a proposed schedule of fixed prices for (a) the first year of the next regulatory control period and (b) for each subsequent year of that period using the approach set out in the Draft Decision. The proposed charges have been developed using the modified approach set out in the Draft Decision.

As required by the Draft Decision, all prices distinguish between the maintenance cost and the capital cost. A building block approach is used for capital charges to apply to existing assets and an annuity approach applies to capital charges for assets constructed after 30 June 2009. Efficient operating costs are used to determine operating charges that are applied to both existing and new assets.

[7] Refer page 346 of the *AER*'s New South Wales Draft distribution determination 2009-10 to 2013-2014.

While Country Energy considers it has complied with the direction given by the AER in its Draft Decision, it suggests that the Draft Decision could be enhanced or simplified to address the following matters:

- Merging tariff classes 4 and 5 in the scheme as set out in the Draft Decision;
- Simplify of the charges to apply for the early replacement of assets at the customer's option (tariff class 6 in the scheme set out in the Draft Decision); and
- Assets that are currently charged under Country Energy's Tariff Type 2, which incorporates a charge for future asset replacement, are transferred to the AER's proposed new tariff class 2. A capital charge would no longer payable but the commitment to fund the future first replacement at the end of asset life would remain unchanged.

11.3 *National Electricity Rules* requirements

Clause 6.2.3A(a) of the transitional 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 *Rules* divides direct control services into;

- standard control services; and
- alternative control services.

Alternative control services may be regulated using a building block determination.

11.4 Summary of Draft Decision

The Draft Decision states that each NSW DNSP is required 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 relates to public lighting assets constructed before 1 July 2009. The second relates 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 of the Draft Decision. 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*.

The *AER* considers that compliance with the control mechanism can be demonstrated through an annual approval of charges 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* after the first year.

11.5 Country Energy's proposed enhancements/clarifications to the Draft Decision

Tariff class designations and structure

Country Energy agrees that *tariff class* designations need to reflect varying arrangements for the funding of street lighting assets, since funding arrangements determine whether capital charges are applicable.

Country Energy suggests that capital charges currently are, and should continue to be based solely on whether the capital for purchase or construction was provided by the DNSP or the Customer (regardless of ownership).

This includes those assets that were originally funded by Councils or developers and then gifted to Country Energy via various mechanisms, including direct transfer, capital contributions or other arrangements.

Country Energy's proposed *tariff classes* are set out in Table 28 below. Country Energy considers the proposed classes align with responsibility for capital provision and maintenance.

Tariff class	Tariff designation	Charges based on…	Capital provided	Maintenance
Assets constructed before 1 July 2009				
1	DNSP funded & maintained	Maintenance cost, capital charge (using RAB)	CE	CE
2	Customer funded, DNSP maintained	Maintenance cost only	Customer	CE
Assets constructed after 1 July 2009				
3	DNSP funded & maintained	Maintenance cost, capital charge (using Annuity)	CE	CE
4[8]	Customer funded, DNSP maintained	Maintenance cost only	Customer	CE
5	DNSP funded, early replacement at customer request	Maintenance cost, capital charge (Annuity) adjusted for lantern funding	CE	CE

Table 28 - Summary of tariff classes and their determination (amended from Table 17.8 of Draft Decision)

If the *AER* accepts the designation system proposed, then, as illustrated in the table above, it would seem sensible to merge *tariff classes* 4 and 5 as proposed in the Draft Decision, since the associated charges are identical. This proposal also aligns the tariff structure for assets constructed before and after 1 July 2009. At present, *tariff class* 2 applies to both customer owned and customer funded assets, whereas *tariff classes* 4 and 5 are separated. Otherwise, for consistency, it would appear that the before 1 July 2009 tariff should also be separated into ownership and funding.

[8] including customers on Tariff Type 2 prior to 1 July 2009 and replacement occurs at the end of the life of assets in existence on 1 July 2009 (first replacement only).

Early replacement

Country Energy notes in respect of the setting of tariffs for early replacement (*tariff class* 6 as set out in the Draft Decision[9]), that residual asset charges would be payable by customers in respect of assets with a classification of *tariff class* 1 or 3, but not in respect of assets of classification *tariff class* 5 (as set out in the Draft Decision). Where customers fund the asset subject to early replacement, the assets would remain in *tariff class* 5 (or 4 for that matter) and there would be no requirement for Country Energy to recover a residual asset cost. There would therefore appear to be no requirement to apply *tariff class* 6 to assets with *tariff classes* 4 and 5 classification.

Country Energy agrees that, where an asset's classification is subject to a) *tariff class* 1 or 3 and b) early replacement at the customer's option, then early replacement charges are payable under tariff class 6. Country Energy notes that these charges include two components: a) one-off charges and b) ongoing charges, as follows:

- One-off charges payable in full on early replacement, representing recovery for the following:
    - a residual asset charge calculated on the replaced asset based on remaining life determined through an assessment of the asset's condition or default *AER* value;
    - the efficient capital replacement cost; and
    - the efficient installation cost, after including discounts to the standard installation cost from inclusion, if possible, of early replacements within a bulk lamp replacement cycle.
- Ongoing charges for *tariff class 6* will incorporate
    - efficient maintenance cost (as per *tariff class* 3)
    - a capital charge on the bracket and pole where applicable (dedicated pole), but not on the lantern asset, as this would have been funded by the customer.

Tariff rates under *tariff class* 6 will be based on the rates used for *tariff class* 3, adjusted in line with the factors above. Country Energy suggests that, for clarity, in its discussion on early replacement in the final decision, the *AER* distinguish between one-off and ongoing charges under *tariff class* 5.

Transition from Tariff Type 2 for existing assets

The modified approach set out in the Draft Decision (under section 17.6.11) appears to propose that the new *tariff class* 1 would apply to assets currently charged under Country Energy's existing Tariff Type 2. Section 17.6.11.2 appears to envisage an arrangement for the transition from the existing Tariff Type 2 under which one-off, customer specific, adjustments are made to the regulated asset base (RAB) used for the calculation of *tariff class* 1. The Draft Decision states in relation to the calculation of *tariff class* 1 rates that:

> *"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."*

The existing Tariff Type 2 includes a component representing a contribution toward the *future* replacement of those Tariff Type 2 assets currently in existence. This is distinct from assets existing on 30 June 2009 on which capital charges cover both a return on and of capital *already* invested. The Draft Decision already envisages that those assets will be transferred to the new *tariff class* 1.

Country Energy's alternative proposal is to apply the *AER*'s *tariff class* 2 to Country Energy's existing Tariff Type 2. The Country Energy proposal means future charges in relation to assets which currently attract the Tariff Type 2 will be set at levels necessary to cover efficient maintenance costs only. Charges would no longer incorporate an element toward the future capital cost of replacement.

[9] All references in the discussion below are to the Tariff numbering scheme set out in the Draft Decision, not as set out in the table above.

Importantly, while this proposal means total charges will be reduced, Country Energy retains its existing commitment for the future replacement of the assets to which the *tariff type* 2 is applied. For clarity, Country Energy's commitment is to replace public lighting assets charged under Tariff Type 2 at the end of the asset's life in respect of those assets to which the existing Tariff Type 2 applies and are in existence as at the date of the Final Determination.

Upon the first replacement of such assets, *tariff class* 4 would then apply and charges will be set to recover only the efficient maintenance cost associated with that asset. In other words, on the first replacement of the asset, there will be no change in the applicable tariff rate. Capital charges would only apply again in the future if the asset were replaced a second time and the customer elected not to fund the replacement itself. In this case, *tariff class* 3 would apply.

This proposal is distinct from the customer option to apply for an early replacement of an asset falling into Tariff Type 2. The replacement commitment does not extend to early replacement. Under early replacement, a residual capital charge would apply under *tariff class* 5 (in the proposed amended *tariff classes* set out in the above table), reflecting the accelerated retirement of the asset in question. In the case of early replacement of Tariff Type 2 assets, the "residual" capital charge reflects a shortening in the period before asset replacement.

Country Energy considers its proposed approach on this matter retains the *AER*'s requirement for appropriate recognition of past customer contributions to the replacement of existing assets.

In light of these points, Country Energy proposes that the *AER*'s Final Determination provides for the transfer of existing Tariff Type 2 assets to the proposed *tariff class* 2. This could be achieved by allowing Country Energy the option of transferring Tariff Type 2 assets to the new *tariff class* 2, instead of *tariff class* 1, as provided for in the Draft Decision.

11.6 Schedule of fixed prices

This section provides summary tables of fixed prices for the purpose of *AER* consideration. A full schedule of fixed prices is provided in appendix H. An explanation of the basis on which proposed prices have been set is provided in the following sections.

Assets constructed before 1 July 2009

Table **29** below sets out proposed fixed rates using the Building Block approach set out in the Draft Decision. *Tariff class* 1 consists of the maintenance charge applying to *tariff class* 2, with the addition of a capital charge based on a roll-forward of the 2004 implied Regulated Asset Base (RAB) for street-lighting assets funded by Country Energy.

Lighting Type	C + O *tariff class* 1	O *tariff class* 2
2*20W TF	$129.59	$62.39
80W MV	$115.97	$48.76
2*14W T5 [10]		
42W CFL	$129.75	$62.54
150W HPS	$141.60	$74.40
250W HPS	$133.81	$66.61
250W MV	$129.80	$62.59
400W MV	$148.02	$80.82

Table 29 – Rates for assets constructed before 1 July 2009 (prices are for a single light on a shared pole)

[10] Country Energy will offer this light from 1 July 2009

Assets constructed after 30 June 2009

Table 30 below sets out proposed fixed rates using the annuity calculation approach set out in the Draft Decision. The presentation assumes that *tariff classes* 4 and 5 in the Draft Determination are combined into a single Tariff, as proposed by Country Energy's structure above.

Tariff class 3 consists of the maintenance charge applying to *tariff class* 4, with the addition of a capital charge using the annuity method, for street-lighting assets funded by Country Energy. Note that the rates for Tariff classes 2 and 4 are identical.

Lighting Type	C + O tariff class 3	O tariff class 4
2*20W TF [11]		
80W MV	$133.80	$48.76
2*14W T5 [12]	$179.06	$64.88
42W CFL	$158.39	$62.54
150W HPS	$220.94	$74.40
250W HPS	$213.69	$66.61
250W MV	$211.18	$62.59
400W MV [13]		

Table 30 – Rates for assets constructed after 30 June 2009 (prices are for a single light on a shared pole)

Price path for 2010-2014

The cost-reflective rates set out above would apply to the first year of the next regulatory period, stating on 1 July 2009. As set out in its June 2008 submission[14], Country Energy proposes to adjust these prices annually in line with the inflation and escalation rates allowed in the general network determination process for underlying cost increases. The public lighting cost reflective prices are established with reference to 2009-10 costs. To the extent that the outturn real cost of labour and other inputs grows faster than the CPI over the 2009 to 2014 regulatory period, the current cost reflective prices will under-estimate the costs of providing the public lighting service.

As SLUoS costs are determined at a single point in time, it will be necessary to use a different methodology to allow for these underlying real increases in costs. In the absence of a mechanism to track real cost increases, Country Energy proposes to escalate the published cost reflective public lighting prices in line with the expected real increases in the cost of providing the service.

As the vast majority of public lighting costs are driven by the cost of labour, Country Energy proposes to escalate the published public lighting prices by the annual increase in EGW wages as a proxy for the underlying real cost increases. This will provide certainty and stability to public lighting customers over the course of the regulatory period.

Country Energy considers this proposed approach is consistent with the *AER*'s proposed control mechanism - an annual approval of changes in the schedules of prices. Under this proposed mechanism 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*.

[11] These lighting types are no longer being installed.
[12] Country Energy will offer this light from 1 July 2009.
[13] These lighting types are no longer being installed.
[14] Refer to page 206 of Country Energy's *Regulatory proposal* 2009-2014.

11.7 Supporting information

This section sets out the basis on which proposed tariffs were calculated. This includes a summary of the key parameters used in the:

- building block calculation;
- annuity calculation; and
- maintenance cost calculation.

Brief comments on changes in parameters since the original Country Energy submission dated June 2009 are also provided.

Building block calculation

In accordance with the Draft Decision, with respect to existing assets, a building block approach was used to calculate tariff levels.

Parameter	Value	Comment
RAB	$15.9m	Closing asset value using roll-forward from 2004 IPART determination
RAB Allocation method	Default	See discussion below
Average remaining asset life	Default	See discussion below
WACC	8.11% pre tax real	WACC applied throughout revised proposal

The closing RAB value of $15.9m is based on a roll-forward from the 2004 determination.[15]

Allocation of RAB between customers

As noted in Country Energy's *regulatory proposal*[16], Country Energy does not have age related information for every public lighting asset in service. Moreover, a tariff structure that reflected the age profile would be unwieldy and administratively unmanageable for both Country Energy and its customers.

Accordingly Country Energy does not propose to allocate the RAB to individual customers based on documented analysis of remaining life estimates. Instead, Country Energy proposes to allocate the RAB equally across all public lighting assets currently falling into the Tariffs 1 and 7. This results in a single fixed price, as set out in the preceding section.

Average remaining asset life

The remaining asset life value affects the calculation of capital charges. The shorter the assumed remaining asset life, the greater the capital charges applicable.

Given the absence of age profile data, Country Energy proposes that a default assumption determined by the *AER* should be applied to determine the average remaining asset life used to calculate capital charges. Country Energy's proposal for the *AER* default remaining life value is 10 years, as contained in Country Energy's *regulatory proposal* dated 2 June 2008 (the "half life" assumption).

[15] Refer to page 202 of Country Energy's *Regulatory proposal* 2009-2014
[16] Ibid page 198

The proposed default remaining life calculation means that *tariff class* 1 would continue to apply after 30 June 2014

Inputs for after 1 July 2009 capital charge calculation

The main inputs for the calculation of the capital charge component are set out below. The asset life assumptions represent a continuation of the values applying in the current *regulatory control period*.

Parameter	Value	Comment
Asset cost	-	Efficient purchase and installation cost
Asset life (lanterns & brackets)	20 years	As applied in current *regulatory control period*
Asset Life (dedicated poles)	35 years	As applied in current *regulatory control period*
Interest rate	8.11% pre tax real	WACC applied throughout revised *regulatory proposal*

11.8 Other Matters - Rebate

Country Energy is of the view that its proposals regarding customer rebates to manage price increments during the transition to cost reflectivity are consistent with the Draft Decision. Accordingly, the approach set out in this revised *regulatory proposal* has been modified to reflect the *AER*'s Draft Decision. Updated rebates for each customer are documented in appendix I.

Glossary

12 Glossary

ACCC	Australian Competition and Consumer Commission
AER	*Australian Energy Regulator*
ARPANSA	Australian Radiation Protection and Nuclear Safety Agency
CEG	Competition Economists Group
CIS	Customer Information System
CPI	Consumer Price Index
DMIA	Demand Management Innovation Allowance
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
EDDiS	Electricity Metering Data Distribution System
EMF	Electric and Magnetic Field
EPA	Environmental Protection Authority
ESDR	Electricity System Development Review
EWON	Energy and Water Ombudsman of New South Wales
EWP	Elevated Work Platform
GDP	Growth Domestic Product
GIS	Geographical Information System
GRP	Gross Regional Product
GSP	Gross State Product
ICT	Information Communication Technology
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
LGA	Local Government Area
MCE	Ministerial Council on Energy
NAMP	Networks Asset Management Plan 2008-09 to 2013-14
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NIEIR	National Institute of Economic and Industry Research

NSC	National Standards Commission
NSW	New South Wales
ODRC	Optimised Depreciated Replacement Cost
PCB	Polychlorinated Biphenyls
PMO	Program Management Office
PPM	Parts Per Million
PoE	Probability of Exceedence
PTRM	Post Tax Revenue Model
QCA	Queensland Competition Authority
RAB	Regulatory Asset Base
RFM	Roll Forward Model
RNSP	*Regulated Network Service Provider*
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SF6	Sulphur Hexafluoride 6
SLUOS	Street Lighting Use of System
STPIS	Service Target Performance Incentive Scheme
SWER	Single Wire Earth Return
TAM	Total Asset Management
TOU	Time of Use
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital
WAPC	Weighted Average Price Cap

Appendices

13 Appendices

13.1 Appendix A – Electricity Forecasts for CE Region – Energy, customer numbers and maximum demands.

13.2 Appendix B – SAHA Response to the AER's Draft Decision – Self Insurance (*Commercial-in-Confidence*)

13.3 Appendix C – CEG Debt and equity raising costs

13.4 Appendix D – CEG Escalators affecting expenditure forecasts

13.5 Appendix E – Directors' Certification Statement

13.6 Appendix F – Information Technology Works Program 2009-2014 (*Commercial-in-Confidence*)

13.7 Appendix G – CEG Rate of return and the averaging period under the National Electricity Rules and Law (*Commercial-in-Confidence*)

13.8 Appendix H – Public Lighting – For Public Release

13.9 Appendix I – Public Lighting – Indicative Rebate Calculations (*Commercial-in-Confidence*)