Decision

NSW and ACT transmission network revenue cap EnergyAustralia 2004–05 to 2008–09

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Contents

Glossary

ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACG	Allen's Consulting Group
AER	Australian Energy Regulator
AESDR	Annual electricity system development review[1]
AGSM	Australian Graduate School of Management
AR	Allowed revenue
Capex	Capital expenditure
CAPM	Capital asset pricing model
code	National Electricity Code
CPI	Consumer price index
CRA	Condition and risk assessment
Draft SRP	Statement of Principles for the Regulation of Transmission Revenues – Draft, August 2004
DRP	Draft regulatory principles[2]
EMRF	Energy Markets Reform Forum
ERAA	Energy Retailers Association of Australia Incorporated
ESC	Essential Services Commission of Victoria
EUAA	Energy Users Association of Australia
GWh	gigawatt hour
IPART	Independent Pricing and Regulatory Tribunal of New South Wales
IT	Information technology
kV	kilovolts
MAR	Maximum allowed revenue
MRP	market risk premium
MVA	Mega volt amperes
MVAr	Mega volt amperes reactive

1 EnergyAustralia annually produces a document known as the AESDR, which summarises its substation loads and load forecasts.

2 ACCC, Draft Statement of Principles for the Regulation of Transmission Revenues, 27 May 1999.

MW	megawatt
NECG	Network Economics Consulting Group
NEM	National Electricity Market
ODRC	optimised depreciated replacement cost
OH&S	Occupational health and safety
Opex	Operating expenditure
PB Associates	Parsons Brinkerhoff Associates
PTRM	Post tax revenue model
QCA	Queensland Competition Authority
RAB	Regulated asset base
RCM	reliability centred maintenance
SKM	Sinclair Knight Merz
SRP	Statement of regulatory principles[3]
TLF	Transmission loss factor
TNSP	Transmission network service provider
Tribunal	Australian Competition Tribunal
TUOS	Transmission use of system
VM	Value management
WACC	Weighted average cost of capital

3 ACCC, Decision statement of principles for the regulation of electricity transmission revenues, 8 December 2004.
ACCC, Decision statement of principles for the regulation of electricity transmission revenues—background paper, 8 December 2004.

Summary

Introduction

EnergyAustralia owns and operates a part of the electricity transmission network in New South Wales (NSW). EnergyAustralia also owns and operates an electricity distribution network in NSW. Currently EnergyAustralia's distribution network is regulated by the Independent Pricing and Regulatory Tribunal of NSW (IPART), and the transmission network is regulated by the Australian Competition and Consumer Commission (ACCC).

On 23 September 2003, EnergyAustralia lodged an application for a revenue cap with the ACCC in respect of its transmission network for the period 1 July 2004—30 June 2009. The ACCC has made this decision following the principles set out in the *Statement of Principles for the Regulation of Transmission Revenues—SRP*.

This decision sets a revenue cap that EnergyAustralia must adhere to when charging customers for transmission services. The ACCC's power to set a revenue cap for a transmission network service provider (TNSP) is set out in the National Electricity Code (code), which requires revenue caps to apply for periods of at least five years. This decision applies for the five year period 1 July 2004 to 30 June 2009.

Framework

The SRP states that the ACCC will use the building block model. The ACCC assesses each building block to determine a total revenue allowance. Using this approach the ACCC makes a decision on forward looking costs in relation to the regulatory asset base (RAB), forecast capital expenditure (capex), forecast operating and maintenance expenditure (opex) and the weighted average cost of capital (WACC). Each of these matters is summarised below, and discussed in detail in the relevant chapters. Service standards and pass-through arrangements are also summarised below, and discussed in detail in the relevant chapters.

Opening asset base

ACCC's approach

The code requires the ACCC to determine the asset value for the 2004–2009 revenue cap. This requires the ACCC to first determine a valuation for assets that existed at the time of the last reset (sunk assets), and, second to roll in a prudent new capex undertaken since then.

Valuation of sunk assets

The approach adopted in the ACCC's SRP is to 'lock in' the asset valuation from the previous revenue reset. That is, to adjust the previous asset valuation for CPI and depreciation without otherwise reviewing the valuations adopted.

In its application, EnergyAustralia proposed a revised optmised depreciated replacement cost (ODRC) valuation of $680.2m for its opening RAB. EnergyAustralia claims the revaluation is warranted because the 1999 valuation contains material errors. EnergyAustralia also states that all of its past capex is prudent and should be included in the opening RAB.

However, the ACCC considers that EnergyAustralia has failed to demonstrate that the ODRC valuation conducted in 1999 contains a sufficient number of material errors to justify using an alternative valuation. Further, the ACCC is unable to determine whether EnergyAustralia's past capex is efficient and does not accept the values included in EnergyAustralia's proposed 2004 ODRC valuation.

The ACCC proposes to adopt a roll-forward methodology in determining an opening RAB for the 2004–2009 regulatory period.

Re-classification of EnergyAustralia's assets

EnergyAustralia has reclassified a number of assets from distribution to transmission. As part of its decision, the ACCC has had to form a view about the valuation of those assets for the purpose of setting the opening RAB.

The main consideration for the ACCC was to ensure that the allocation was consistent between the ACCC and IPART.

The overall impact of the changes is an increase to the transmission RAB of $91.7m from 1 July 2004, with a corresponding reduction in its distribution RAB. This has the effect of increasing EnergyAustralia's proportion of transmission assets from approximately 10 to 12 per cent of its total network asset base.

Past capex

The ACCC has assessed past capex based on the approach set out in its Draft Regulatory Principles (1999) (DRP). This requires the ACCC to form a view about the 'prudency' of EnergyAustralia's capex over the 1999–2004 regulatory period. In order to assist with this assessment the ACCC engaged GHD to review EnergyAustralia's capital governance processes as well as reviewing specific projects.

EnergyAustralia spent considerably more on capex in the 1999–2004 regulatory period than it forecast at the time of the 1999–2004 revenue cap decision. For the projects included in the 1999–2004 revenue cap decision, the ACCC has decided that these projects are prudent investments and they will be rolled into the RAB at their actual cost.

For projects not included in the 1999–2004 revenue cap decision, where EnergyAustralia has demonstrated that its capex projects are efficient, the ACCC will allow the full costs of the projects to be rolled into the opening RAB.

However, the ACCC does not consider that EnergyAustralia has demonstrated a need for the undergrounding of transmission mains at Homebush and hence the ACCC's decision is to exclude this project from the opening RAB.

For the MetroGrid project conducted jointly with TransGrid, the ACCC has determined EnergyAustralia was prudent in undertaking the regulatory test and that, if the investment had occurred as planned then it would have been deemed prudent. However, the ACCC has also determined that the entire cost of the upgrade may not be prudent because of the cost increases. As foreshadowed in the draft decision, the ACCC has reviewed EnergyAustralia's process as the costs of its investment in the MetroGrid project were increasing. Both TransGrid and EnergyAustralia failed to review the decision to proceed with the MetroGrid project when they became aware of the changes to the design and cost of the project.

As in the case of TransGrid, the ACCC considers that EnergyAustralia could have deferred the implementation of the MetroGrid project long enough to review its decision to proceed with the MetroGrid project. There does not appear to have been a jurisdictional or code requirement for the implementation of a modified n-2 standard in any particular timeframe.

The ACCC finds that EnergyAustralia's investment in the MetroGrid project was not prudent.

However, the ACCC will not apply the approach set out in the draft decision to determine the value of prudent capex with respect to EnergyAustralia's investment in the MetroGrid project. Instead, the ACCC will determine the value of prudent capex based on that part of EnergyAustralia's investment in the MetroGrid project that is deemed prudent and allow a return on that prudent investment.

A methodology for determining the value of prudent capex was proposed in chapter 7.3 of the Mountain Associates Report[4] on TransGrid's investment in the MetroGrid project. Using this methodology a prudence adjustment is determined by comparing the present cost of the MetroGrid project as envisaged during the original regulatory test analysis to the MetroGrid project as envisaged in 2001, with the investment in demand side management brought forward and the construction of the project deferred for two years.

When assessed using costs specific to EnergyAustralia, the ACCC has estimated a total prudence adjustment of $32.89m in 1999 dollars. Given the proportion of known costs at 2001, the ACCC has determined that approximately $6.83m in 1999 dollars represents the level of EnergyAustralia's investment in the MetroGrid project that was not prudent.

Further the imprudent cost increase identified was related to the cable tunnel and only 50 per cent of the tunnel was allocated to the transmission RAB. Accordingly, the ACCC determines that an amount of approximately $3.41m in 1999 dollars should be

4 op. cit.

excluded from EnergyAustralia's RAB on the basis that it represents the investment in the MetroGrid project that was not prudent.

With respect to past capex, the ACCC's decision is to allow $124.8m (1999 dollars) to be rolled into the opening RAB.

Decision

In accordance with the ACCC's roll-forward methodology the ACCC's decision is that the opening RAB for the 2004–2009 regulatory period is $635.6m (2004 dollars). This is an increase of approximately 39 per cent on the opening RAB for the 1999–2004 revenue cap. This increase is the result of:

- high capex from the 1999–2004 revenue cap decision
- assets changing classification. The impact of the assets changing classification contributes 52 per cent to the increase in the opening RAB and excluding its impact would result in an increase of only 18 per cent.

Table 1 EnergyAustralia's RAB ($m nominal)

	99–00	00–01	00–02	02–03	03–04
Opening asset base	457.4	450.7	462.6	470.3	469.7
1999 decision capex at actual CPI	3.4	9.2	19.5	9.9	15.9
CPI adjustment	12.8	27.0	13.6	16.2	9.3
Depreciation[(a)]	-22.8	-24.3	-25.4	-26.7	-25.1
Closing asset base	450.7	462.6	470.3	469.7	469.7
add: capex not forecast over 1999–2004					64.0
add: assets changing classification over 1999–2004					91.7
add: return on overspend					10.2
Opening RAB 1 July 2004					635.6

Note: Numbers may not add due to rounding
(a) Adjusted for actual inflation.

The roll forward methodology adopted by the ACCC in its modelling of the revenue cap means the closing balance of the asset base for one year becomes the opening balance for the subsequent year.

Forecast capex

ACCC's approach

As part of the SRP the ACCC has developed an ex ante framework. As this new framework was developed after EnergyAustralia's initial application, EnergyAustralia submitted a supplementary capex application in line with the ex ante framework.

For EnergyAustralia's forward capex, part B of chapter 6 of the code requires that:

- in setting the revenue cap the ACCC must have regard to the potential for efficiency gains in expected operating, maintenance and capital costs, taking into account the expected demand growth and service standards
- the regulatory regime must seek to achieve efficiency in the use of existing infrastructure, efficient operating and maintenance practices and an efficient level of investment
- the regulatory regime must foster an efficient level of investment within the transmission sector and the sectors upstream and downstream of it
- a revenue cap to be set for a period of no less than five years.

The ACCC engaged PB Associates to assist it in assessing the capex program proposed by EnergyAustralia.

Replacement capex

EnergyAustralia proposed $156m for replacement capex out of a total capex proposal of $290m. EnergyAustralia's proposed replacement capex was substantially larger than the capex spent in the past regulatory period. In considering EnergyAustralia's capex for the 2004–2009 regulatory period, the ACCC has increased the replacement expenditure by almost 400 per cent to that spent in the 1999–2004 regulatory period.

The ACCC did not consider that EnergyAustralia's entire replacement expenditure proposal was justified. This decision is based on EnergyAustralia's condition and risk assessment (CRA) methodology. This methodology is discussed in chapter 3.5. EnergyAustralia's CRA assesses the condition of its assets and the impact that a failure of the asset would have on the network. PB Associates considered that if an asset has a low risk of failure and there will only be a low impact to the network if a failure was to occur, then those assets do not warrant replacement in this regulatory period.

However, in moving to its final decision, the ACCC has included the replacement of the Ourimbah substation. This is because EnergyAustralia stated that although some of the assets within the Ourimbah substation could be utilised for more than 5 years, loading issues would warrant their replacement. Further EnergyAustralia stated that the consequences of this substation failing is a loss of supply to about 49,000 customers. In addition EnergyAustralia has noted that an explosive failure has already occurred within this substation.

The ACCC considers the Ourimbah substation to be critical to the supply of the central coast. The ACCC believes EnergyAustralia has demonstrated that the expenditure for the Ourimbah substation replacement is warranted and the project should go ahead this regulatory period. Therefore, the ACCC is proposing to include $24m for the replacement of the Ourimbah substation.

Augmentation capex

In relation to augmentation capex, the ACCC has increased it slightly since the supplementary draft decision to allow for EnergyAustralia's revised forecast costs for the lower Hunter 132kV development. In addition the ACCC has made an allowance for a number of contingent projects.

Contingent projects

For this regulatory period, there are three projects that are classified as contingent projects.

The inclusion of these projects as contingent projects means the ACCC has decided to provide an allowance for them during this regulatory period. However, before this occurs, the ACCC has determined 'triggers' that must be present. These are discussed in appendix A.

Due to the uncertainty regarding the costing of the contingent projects the ACCC will undertake a further process to determine the allowance. Appendix B outlines the process that EnergyAustralia must undertake when a trigger event has occurred.

This decision also includes a provisional indicative allowance for feeders 908 and 909. This is because the project is certain to go ahead this regulatory period, however the costings have not been finalised. The indicative allowance is based on the minimum amount that the project will require.

Decision

The ACCC's decision is to allow $243m capex over the 2004-2009 regulatory period. However the maximum allowed revenue (MAR) was modelled on a capex allowance of $207m due to contingent projects (see chapter 3.9.4).

Table 2 represents the ACCC's decision in relation to an efficient amount of total capex.

Table 2 Total capex

Capex ($m 2004–05)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's forecast						
Ex ante capex allowance	50.5	31.5	31.1	34.8	32.8	180.7
Contingent capex	0.8	8.9	42.8	37.8	19.5	109.7
Total	51.2	40.4	73.9	72.5	52.4	290.4
ACCC's decision						
Ex ante capex allowance	48.0	29.4	33.8	32.5	26.8	170.5
Contingent capex	0.4	2.7	28.2	25.4	15.7	72.4
Capex allowance[(a)]	48.4	32.0	62.0	57.9	42.5	242.9

(a) The capex allowance includes all contingent projects. The MAR is only modelled on capex of $207m. This does not include an allowance for all contingent projects (see chapter 3.9.4).

The capex allowance that the ACCC has proposed for EnergyAustralia is not designed to fund the construction of a list of identified projects. As noted in the SRP background paper (at page 55) the capex allowance does not entail project-specific approval and there is no constraint on TNSPs investing in a different suite of projects to those used in the calculation of the allowance. Similarly, the fact that a project was not considered by the ACCC in the determination of the revenue cap does not necessarily mean that it should not be funded from the capex allowance.

The capex allowance proposed by the ACCC is an amount of money available to EnergyAustralia for it to allocate to projects that it considers are necessary in maintaining the reliability of its network. It is EnergyAustralia's responsibility to allocate the capex allowance efficiently to ensure any risk of failure to its network is minimised.

Cost of capital

ACCC's approach

The ACCC uses the risk adjusted rate of return required by investors in commercial enterprises facing similar business risks to establish the WACC for EnergyAustralia. Details are set out in the SRP.

Updating WACC parameters

In previous revenue cap decisions, the WACC was updated for bond rates that were based on a moving average period from the date of the final decision. Therefore under normal circumstances the ACCC would update the WACC for prevailing bond rates at the time of the originally scheduled final revenue cap decision in mid 2004.

However, this decision has been delayed due to the application of the incentive framework for capex as set out in the SRP. In 2004, a NSW derogation to the code (clause 9.16.5) enabled TransGrid and EnergyAustralia to set the NSW prices for 2004–05 based on the proposed MARs that were set out in the ACCC's draft decisions dated 28 April 2004.

Given the price for 2004–05 has already been set, the ACCC considers that it would be inappropriate to retrospectively adjust the forecast WACC for current bond rates in the market. Instead the ACCC will finalise its estimate of the WACC for EnergyAustralia with bond rates as at 28 April 2004.

Decision

The ACCC has considered the values that should be assigned to EnergyAustralia's WACC, given the nature of its business and current financial circumstances. The parameter values adopted for this decision are shown in table 3.

Table 3 Comparison of cost of capital parameters

Parameter	ACCC decision	ACCC draft decision	EnergyAustralia's proposal
Nominal risk-free interest rate (r_f)	5.98 %	5.89 %	5.55 %
Real risk-free interest rate (rr_f)	3.41 %	3.37 %	3.34 %
Expected inflation rate (f)	2.49 %	2.44 %	2.14 %
Debt margin (over r_f)	0.90 %	0.87 %	1.475 %
Cost of debt $r_d = r_f$ + debt margin	6.88 %	6.76 %	7.025 %
Market risk premium (r_m-r_f)	6.00 %	6.00 %	6.00 %
Gearing (D/V)	60 %	60 %	60 %
Value of imputation credits γ	50 %	50 %	50 %
Asset beta β_a	-	0.40	0.425
Debt beta β_d	-	0.00	0.00
Equity beta βe	1.00	1.00	1.06
Nominal post-tax return on equity	11.98 %	11.86 %	11.89 %
Post-tax nominal WACC	6.94 %	6.84 %	6.95 %
Pre-tax real WACC	7.06%	6.94 %	7.47 %
Nominal vanilla WACC	8.92%	8.80 %	8.97 %

Operating and maintenance expenditure

ACCC's approach

In order to judge whether or not EnergyAustralia's proposed opex requirement and hence operating and maintenance practices are efficient, the ACCC needs to be confident of the starting point for future expenditures. The ACCC has determined a starting point based on a review of EnergyAustralia's opex in the 1999–2004 regulatory period. The starting point also reflects adjustments required because of changes to EnergyAustralia's transmission asset base and changes to its allocation methodology for estimating transmission opex.

EnergyAustralia's proposed opex is used as the basis for the opex allowance estimated by the ACCC. The ACCC makes two key adjustments to EnergyAustralia's proposed opex: a starting point adjustment and a further adjustment for specific cost drivers.

Adjustments

EnergyAustralia proposes a total opex allowance of $24.4m in 2004–05 increasing in real terms to $27.7m by 2008–09. This proposed opex requirement has been developed taking into account the increased amount of transmission assets and using the revised allocation of opex by asset class.

The ACCC has made adjustments for identified efficiencies, assets re-classified as transmission and a new cost allocation framework. These adjustments equate to annual reduction in EnergyAustralia's opex of $0.43m for the 2004–2009 regulatory period. This reflects the ACCC's assessment of the efficient opex for transmission assets if the new asset definition and allocation framework is used.

Specific savings

The opex allowance for the 2004–2009 regulatory period is then calculated using EnergyAustralia's proposed opex, adjusted for future efficiency savings identified by the ACCC.

The ACCC identified specific savings in relation to IT and a confidential project.

Decision

The overall impact of the ACCC's adjustments to EnergyAustralia's opex claims is shown in table 4.

Table 4 EnergyAustralia’s opex ($m 2003–04)

	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia’s proposal[(a)]	24.4	25.7	26.6	27.1	27.7	131.6
less: starting point variation ($0.43)	23.9	25.3	26.1	26.7	27.3	129.4
less: cost driver variation						
confidential project	0.1	(1.4)	(1.4)	(1.4)	(1.4)	(5.6)
IT	(0.7)	(0.7)	(0.7)	(0.8)	(0.8)	(3.6)
self insurance	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)
add: debt raising cost	0.4	0.4	0.4	0.4	0.4	1.8
ACCC opex	23.7	23.5	24.3	24. 9	25.5	121.9

(a) EnergyAustralia’s opex forecasts do not include debt raising costs as they were included in its WACC calculations.

Pass through

Pass through rules allow a TNSP’s revenue to be adjusted for expenditure by the TNSP during the regulatory period when a specified risk eventuates.

Under a pass through mechanism, if the specified risk (the pass through event) occurs, the MAR is adjusted for the resulting impact on the TNSP’s expenditure (opex or capex). As the costs of the event are passed through, the mechanism transfers risk from the TNSP to users.

The ACCC affirms its preference, as set out in chapter 7 of the SRP Background Paper, to manage the uncertainty of unforeseeable events using a revenue cap reopener. However, as the code has not been amended at this time, the ACCC has included pass through rules in EnergyAustralia’s revenue cap. This decision reflects the particular circumstances of EnergyAustralia and does not alter the ACCC’s general approach outlined in the SRP.

The revenue cap set by the ACCC for EnergyAustralia for the period 2004–2009 includes the pass through rules for the following events:

- a change in taxes event
- an insurance event
- a network (grid) support event
- a service standards event
- a terrorism event.

Service standards

ACCC's decision is that for the purposes of service standards EnergyAustralia should report the performance measures defined in appendix D. All measures should be recorded and reported annually based on calendar years, in accordance with the service standards guidelines, for the purpose of improving the incentives that can be offered in the next regulatory reset.

Further, for the 2004–2009 regulatory period, EnergyAustralia has a financial incentive applying to its performance as measured by transmission circuit availability.

Table 5 Performance incentive target

Performance measure	Revenue at risk	Collar	Target	Cap
Transmission circuit availability (%)	1%	94.46	96.96	98.96

In addition to this, the ACCC requires that EnergyAustralia report on the other performance measures contained in its service standards guidelines. This reporting requirement excludes the need to report on inter-regional constraints because EnergyAustralia does not own or operate any inter-regional assets.

Total allowed revenue

The ACCC's role as regulator of transmission revenues is limited to determining a TNSP's MAR. The MAR is calculated by adding (or deducting) a financial incentive related to service standard performance and pass through amounts to (or from) the allowed revenue (AR).

In its application, EnergyAustralia asked for a smoothed revenue of $108m in 2004–05, increasing to $128m in 2008–09. In 2003–04, EnergyAustralia's comparable AR is $78m.

The ACCC proposes an unsmoothed revenue allowance that increases from $95.1m in 2004–05 to $119.3m in 2008-09, as shown in table 6.

By comparison, the ACCC's supplementary draft decision proposed revenues of $90.0m in 2004–05 rising to $111.1m in 2008–09.

This under recovery of about $4m has been smoothed, in net present value (NPV) terms, across the remaining four years MAR.

Table 6 EnergyAustralia's unsmoothed AR

Revenue ($m nominal)	04–05	05–06	06–07	07–08	08–09
Return on capital	56.7	60.3	62.3	66.1	69.4
Return of capital	11.0	12.1	13.4	14.8	16.2
Operating expenses	24.3	24.7	26.2	27.5	28.8
Estimated taxes payable	6.3	7.4	8.0	8.6	9.5
Value of franking credits	-3.1	-3.7	-4.0	-4.3	-4.7
Unadjusted revenue allowance	95.1	100.9	105.9	112.7	119.2

1 Introduction

The ACCC has investigated how much revenue EnergyAustralia requires to provide non-contestable transmission services to NSW customers. This decision sets a revenue cap that EnergyAustralia must adhere to when charging customers for transmission services.

The ACCC's power to set revenue caps for TNSPs is set out in the code, which requires revenue caps to apply for periods of at least five years. The previous revenue cap[5] that the ACCC set for EnergyAustralia was for the period 1 July 1999 to 30 June 2004. This decision applies for the five year period 1 July 2004 to 30 June 2009.

The code provides a broad set of objectives and principles that the ACCC aims to achieve when setting revenue caps. However it does not provide details about how the ACCC should design and apply revenue caps. Given this, the ACCC developed the SRP which provides the details of the ACCC's approach when setting revenue caps.

The remainder of this chapter discusses the:

- consultation process
- objectives of a revenue cap
- regulatory principles
- structure of this report.

1.1 Consultation process

The ACCC has undertaken the following consultation process in considering the appropriate revenue cap for EnergyAustralia.

23 September 2003	EnergyAustralia submitted its revenue cap application. The application outlined EnergyAustralia's views on the key elements of the building block components. The ACCC called for interested parties to make submissions on the application, and engaged GHD to review the application.
30 January 2004	Interested party submissions on the application closed. Six submissions were received and are available on the ACCC's website.[6]
29 March 2004	GHD's report[7] on the application was placed on the ACCC website and interested parties were asked to make submissions on GHD's report.

5 ACCC, Decision NSW and ACT Transmission Network Revenue Caps 1999/00–2003/04, 25 January 2000.

6 http://www.accc.gov.au

7 GHD, Australian Competition and Consumer Commission EnergyAustralia Regulatory Review Capital Expenditure and Asset Base, Operational Expenditure and Service Standards Report, 29 March 2004.

9 April 2004	Submissions on GHD's report closed. Five submissions were received and are available on the ACCC's website.
10 March 2004	The ACCC released a discussion paper[8] about how it intended to evaluate capex. This was released as part of the review of its regulatory principles.
20 April 2004	EnergyAustralia agreed to resubmit its forecast capex considering the ACCC's proposed regulatory principles in relation to capex.
28 April 2004	The ACCC publishes its draft decision[9] for EnergyAustralia, excluding the forecast capex component. For indicative purposes the ACCC used EnergyAustralia's proposed capex, noting that it would be reviewed after EnergyAustralia resubmits its forecast capex .
2 July 2004	Interested party submissions on the draft revenue cap decision closed. Eleven submissions were received and are available on the ACCC's website.
18 June 2004	The ACCC held a public forum on EnergyAustralia's revenue cap. The presentations made to the public forum and the written submissions that accompanied them are available on the ACCC's website.
29 October 2004	EnergyAustralia submitted its revised forecast capex. The ACCC called for interested parties to make submissions, and engaged PB Associates to review, the revised forecast capex.
17 December 2004	The ACCC received PB Associates' report on EnergyAustralia's revised forecast capex. The ACCC called for interested parties to make submissions on PB Associates' report.
14 January 2005	Interested party submissions on EnergyAustralia's revised forecast capex and PB Associates' report closed. Three submissions were received and are available on the ACCC's website.
3 March 2005	The ACCC released it supplementary draft decision[10], which considers EnergyAustralia's revised capex forecast and its impact on the original draft revenue cap.
18 March 2005	The ACCC held a public forum in relation to its supplementary draft decision. Interested parties made presentations to the forum on various issues pertaining to the supplementary draft decision. A summary of the discussion is available on the ACCC's website.
24 March 2004	Interested party submissions on the supplementary draft decision closed. Two submissions were received and are available on the ACCC's website.

The revenue cap process for EnergyAustralia (and TransGrid) was conducted concurrently with the ACCC's review of its DRP. On 18 August 2004, the ACCC released its proposed revised statement of regulatory principles (the draft SRP). This

8 ACCC, Supplementary discussion paper, Review of the draft statement of principles for the regulation of transmission revenues capital expenditure framework, 10 March 2004.

9 ACCC, *Draft decision NSW and ACT Transmission Network Revenue Caps—EnergyAustralia 2004/05–2008/09*, 28 April 2004.

10 ACCC, Supplementary draft decision *NSW and ACT Transmission Network Revenue Caps—EnergyAustralia 2004–05 to 2008–09*, 2 March 2005.

impacted on the framework for the treatment of forecast capex. The ACCC provided EnergyAustralia with the opportunity to lodge a supplementary application regarding forecast capex, and also published a supplementary draft decision on forecast capex using the revised framework from the draft SRP.

1.2 Code requirements

In setting revenue caps for TNSPs the ACCC sets the maximum revenues that a TNSP can recover from its customers. In undertaking this responsibility the ACCC is required by the code to:

- try to achieve the objectives set out in clause 6.2.1
- apply the principles set out in clause 6.2.2
- apply the form of regulation set out in clause 6.2.3.

1.3 Regulatory principles

On 27 May 1999 the ACCC released its DRP. Under those regulatory principles the ACCC has set revenue caps for:

- TransGrid, 25 January 2000
- EnergyAustralia, 25 January 2000
- Snowy Mountains Hydro Electric Authority, 7 February 2001
- Powerlink, 1 November 2002
- ElectraNet SA, 11 December 2002
- SPI PowerNet, 11 December 2002
- Murraylink, 1 October 2002
- Transend Networks, 10 December 2003.

After setting revenue caps for all NEM TNSPs the ACCC considered it appropriate to review the DRP. The ACCC began its review in August 2003 with the release of a discussion paper.[11]

The ACCC, after extensive consultation, released its SRP on 8 December 2004. In revising the regulatory principles, the ACCC sought to improve incentives by:

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11 ACCC, Discussion paper, 2003 review of the draft statement of principles for the regulation of transmission revenues, 20 August 2003.

- moving to an ex ante assessment of capex, known as the ex ante framework
- providing a mechanism to assess uncertain but significant capex, known as contingent projects
- allowing the revenue cap to be re-opened if unexpected but material events impact the TNSP, known as revenue cap re-opener events
- improving transparency of TNSP performance
- establishing an efficiency carry forward mechanism

1.4 Structure of this report

The remainder of this decision reviews EnergyAustralia's:

- opening asset base (chapter 2)
- forecast capex (chapter 3)
- cost of capital (chapter 4)
- operating expenditure (chapter 5)
- pass through (chapter 6)
- service standards (chapter 7).
- total revenue (chapter 8).

Appendix A outlines the contingent projects and the trigger events for EnergyAustralia's future capex program. If a contingent project is triggered, the ACCC will assess the project by undertaking the process outlined in appendix B.

Appendix C analyses the financial indicators of EnergyAustralia's business performance as a result of this revenue cap. Appendix D contains the details of the ACCC decision on service standards. Finally Appendix E contains the pass through rules that will apply to EnergyAustralia.

2 Opening asset base

2.1 Introduction

The objective of this chapter is to determine a value for EnergyAustralia's non-contestable transmission assets as at 1 July 2004. This chapter sets out the:

- code requirements
- regulatory principles
- EnergyAustralia's application
- issues raised on the application
- ACCC's 1999–2004 revenue cap decision
- issues raised on the draft decision
- assessment of specific projects
- ACCC's decision.

2.2 Code requirements

In determining an opening RAB for a revenue cap decision, the ACCC is bound by the relevant provisions of the code. Clause 6.2.3(d)(4)(iv) of the code states that:

> subject to clauses 6.2.3(d)(4)(i) and (ii), valuation of assets brought into service after 1 July 1999 ('new assets'), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the ACCC and in determining the basis of asset valuation to be used, the ACCC must have regard to:
>
> A: the agreement of the Council of Australian Governments of 19 August 1994, that deprival value should be the preferred approach to valuing network assets;
>
> B: any subsequent decisions of the Council of Australian Governments; and
>
> C: such other matters reasonably required to ensure consistency with the objectives specified in clause 6.2.2.

The code gives the ACCC the discretion to determine the asset value for the 2004–2009 revenue cap, subject to the limitations detailed above. This differs to the 1999–2004 revenue cap, where clause 6.2.4(d)(iii) of the code specifies that the ACCC must value sunk assets at the value determined by the Jurisdictional Regulator or consistent with the regulatory asset base established in the jurisdiction.

It should be noted that, in relation to the 1999–2004 revenue cap decisions for TransGrid and EnergyAustralia, the ACCC was the Jurisdictional Regulator, (see clause 9.16.1). Accordingly the ACCC undertook an ODRC valuation of the transmission networks operated by TransGrid and EnergyAustralia.[12]

2.3 Regulatory principles

To establish the asset value underlying the revenue cap for 2004–2009, the ACCC has applied the regulatory principles in the DRP and those discussed in the 1999–2004 revenue cap decision.[13] The ACCC is using these older regulatory principles as the SRP was not available when EnergyAustralia's last revenue cap was set.

The DRP elaborated on how the ACCC interpreted its code obligations with regard to regulating capital investment. The DRP states that the ACCC will assess the prudence and efficiency of capex ex post.

Under the DRP the forecast capex included in the RAB at the start of the regulatory period provides TNSPs with cash flow to finance their expected investment program. While this forecast is based on a reasonable assessment of likely investment over the period of the revenue control, it is not intended to represent a definitive assessment of efficient investment.

Difference between the actual expenditure and the forecast expenditure cannot simply be attributed to higher or lower efficiency than that expected. Instead the ACCC foreshadowed in the DRP that it would assess the prudence of all capex undertaken.

The ACCC's approach to the determination of what constitutes a prudent and efficient investment is discussed in chapter 6 of the TransGrid revenue cap decision 2004–2009.

2.4 EnergyAustralia's application

Initially, EnergyAustralia proposed an opening RAB of $702m[14], which was based on an ODRC valuation conducted by SKM. EnergyAustralia's application includes limited information about the capex it undertook during the 1999–2004 regulatory period.

On 18 November 2003 EnergyAustralia submitted a summary of its capex over the 1999–2004 regulatory period, including project specific documentation, stating that all of its past capex was prudent and the foregone rate of return on its capital overspend should be included in the opening RAB.

On 18 February 2004 EnergyAustralia submitted an updated opening RAB to the ACCC which considered more up to date information on the timing of capex and

12 ACCC, NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04, 25 January 2000 pp. 60 and 135.

13 ibid.

14 EnergyAustralia's submission to ACCC Transmission revenue determination 2004–2009, section D, September 2003.

other issues. The new opening RAB proposed by EnergyAustralia was $680.2m and is based on an ODRC valuation by SKM.

2.5 Issues raised on the application

2.5.1 Roll forward versus new ODRC valuation

EnergyAustralia proposed an opening RAB for the 2004–2009 regulatory period based on an ODRC methodology. It has proposed this new valuation because it considers that there are inconsistencies and errors in the opening RAB for the 1999–2004 revenue cap. EnergyAustralia also states the new valuation is necessary because the ACCC did not provide it with initial advice on the proposed roll forward methodology.

Although it proposed a new ODRC valuation, EnergyAustralia states that it supports the principle of the roll forward approach to determine the RAB.

Submissions

In its submission on the draft decision, EnergyAustralia states that the roll forward approach is inconsistent with the DRP. It considers the DRP advocates using the ODRC framework. EnergyAustralia states that the decision to use a roll forward approach has implications for other parts of the regulatory framework, including the ACCC's framework for the assessment of capex.

EnergyAustralia has expressed its dissatisfaction with the process the ACCC has undertaken in developing its roll forward methodology. EnergyAustralia contends that the ACCC has not publicly consulted on the methodology and EnergyAustralia specifically was not consulted on the roll forward approach.

However, overall EnergyAustralia notes that the proposed approach appears to be reasonable, although it has some specific concerns. EnergyAustralia's concerns with the roll forward approach include:

- the roll forward method does not preserve financial capital maintenance for opex
- a mathematical approach determines remaining asset life instead of EnergyAustralia's proposed asset life estimates
- an error in the calculation results in the RAB being understated by about $6.5m.

The joint submission from a customers' group[15] supports the roll forward approach and rejects the contention that an ODRC revaluation is appropriate. It notes that given the information asymmetry and resource availability all revaluations of the asset base will only be upward to the detriment of the customers.

15 The customers' group consists of Australian Business Ltd, the Australian Consumers' Association, the Energy Action Group, the Energy Users' Association of Australia, and the National Farmers' Federation.

The EMRF submission notes that the distribution businesses in NSW also claimed similar mistakes and anomalies in supporting their requests for revaluations of the asset base for the 2004 distribution pricing review. These requests were rejected by IPART.

ACCC's considerations

In the DRP the ACCC notes that it has the power to revalue the RAB using an ODRC methodology. Proposed statements S4.2 and S4.3 of the DRP discuss the circumstances in which this might occur and the procedure that would be applied. Further, proposed statement S4.2 states that if the ACCC chooses to revalue the RAB it would notify the TNSP prior to the commencement of the regulatory review.

Also the DRP specifically recognises that 'the Commission may not need to consider a full ODRC every regulatory period'.[16]

The ACCC considers that a roll-forward approach is not contradictory or inconsistent with the DRP or the code.

The ACCC undertook an ODRC valuation of EnergyAustralia's transmission assets to determine the RAB as at 1 July 1999. EnergyAustralia's 2003 application did not provide details of any material errors in this ODRC valuation.

After reviewing EnergyAustralia's 2003 application, the ACCC sought a full list of errors and inaccuracies in the 1999 ODRC valuation. In particular it sought details of any material inconsistencies between the TransGrid and EnergyAustralia valuations and their order of magnitude.

On 31 October 2003 EnergyAustralia submitted additional information on asset valuation, which included a single example of how angle structures can cost up to five times more than a standard structure. It outlined a single pricing example for one customer based on different valuations and stated that:

> the estimated magnitude of these types of unit rate differences undervalue EnergyAustralia's total regulatory asset base by more than 8 per cent.[17]

Given the lack of supporting information, the ACCC considers that EnergyAustralia has failed to demonstrate that the ODRC valuation utilised in the 1999–2004 revenue cap is materially affected by error.

Therefore the ACCC does not consider a revaluation is justified and will roll forward the opening asset base from the 1999–2004 revenue cap decision.

In adopting the roll forward approach the ACCC has addressed EnergyAustralia's specific comments as follows:

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16 ACCC, 'Statement of Principles for the Regulation of Transmission Revenues—Draft', 27 May 1999 p. 49.

17 ibid p. 37.

- EnergyAustralia claimed that the ACCC did not consult it about the roll forward approach. The ACCC provided its proposed roll forward methodology to EnergyAustralia prior to making its draft decision.

- the ACCC rejects EnergyAustralia's proposal to include any opex overspend in the RAB. The ACCC considers that such an approach is akin to cost plus regulation and is not consistent with the principles in clause 6.2.2 of the code which provides that the regulatory regime must be incentive based and achieve, amongst other things:

  - an equitable allocation between users and TNSPs of efficiency gains reasonably expected by the ACCC to be achievable by the TNSP[18]

  - a sustainable commercial revenue stream which includes a fair and reasonable rate of return to TNSPs on efficient investment, given efficient operating and maintenance practices.[19]

- EnergyAustralia claimed that the draft decision was not based on remaining asset lives it provided. The ACCC applied the remaining asset lives estimates provided by EnergyAustralia in the draft decision. This has now been agreed by EnergyAustralia.

- the ACCC has checked its roll forward modelling and has discovered an error in the calculation. The error understated the RAB by approximately $1.8m.

  The ACCC's model calculates a return on capital based on the opening RAB for each year and capex is not recognised until the year after it is capitalised. Actual capex is incurred evenly throughout the year, so a reasonable assumption is that capex on average takes place half-way through the year. Without an adjustment, no return on capital would be provided in the year capex is incurred. Therefore, to address the timing difference of modelling capex, a half-WACC is provided (capitalised and recovered over the life of the assets) to compensate for the 6 month period before capex is included in the RAB.[20]

  The error occurred because the half-WACC allowance for some past capex being rolled into the RAB was omitted in the draft decision. The ACCC has provided an updated model to EnergyAustralia which corrects for this error.

The ACCC's decision to adopt the roll forward methodology in determining a RAB as at 1 July 2004 is based on a number of factors, including:

- locking in the existing RAB value to reduce regulatory uncertainty

- it is less likely to deter investment compared to periodic revaluations

18 Code clause 6.2.2(b)(1).

19 Code clause 6.2.2(b)(2).

20 Strictly speaking, the half year vanilla WACC is calculated by the square root of (1 + vanilla WACC) to account for the compounding effect on an annual rate.

- the ACCC considers that the initial valuation for the 1999–2004 regulatory period is appropriate.

In rolling forward the asset base, the ACCC has used the method shown in Box 2.1.

Box 2.1 ACCC's roll forward methodology

Opening asset base

+ **capital expenditure** – **depreciation** – **asset disposals** + **indexation by CPI**

= Closing asset base

Details on the roll-forward methodology utilised for both TransGrid and EnergyAustralia can be found in the TransGrid revenue cap decision 2004–2009 (chapter 5). The only difference between the roll forward methodology used for TransGrid and EnergyAustralia relates to the calculation of depreciation and asset lives. For TransGrid, the ACCC accepted the average remaining asset life methodology proposed by TransGrid based on National Economic Research Associate's (NERA) method. For EnergyAustralia, the ACCC has utilised an approach whereby assets are grouped into categories and depreciated using the average remaining asset life for assets in the category. As stated above, the average remaining asset lives are revised figures provided by EnergyAustralia.

2.5.2 Assets re-classified as transmission

In August 2003 EnergyAustralia notified IPART and the ACCC of a number of changes in the configuration of its network assets. EnergyAustralia states that it has a number of system assets which have changed or would change classification from distribution to transmission before 30 June 2004. These changes in classification are the result of system changes or augmentations to the network over the 1999–2004 regulatory period. The value of these assets is $61.4m. The assets are listed in table 2.1.

On 4 February 2004 EnergyAustralia notified IPART and the ACCC of an error in its August 2003 advice about the assets changing classification from 1 July 2004. EnergyAustralia stated that its Wyong and Charmhaven zone substations were not included in the list of assets changing classification when they should have been. The two substations have a total value of $20.5m.

EnergyAustralia also advised the ACCC and IPART that it would have a number of assets changing classification over the course of the 2004–2009 regulatory period.

Table 2.1 Assets re-classified as transmission as at 1 July 2004

Location	Asset
Inner Sydney Metropolitan	Feeder 9SA—Beaconsfield West to Surry Hills
Central Coast	Feeder 957—Vales Point to Ourimbah
Central Coast	Feeder 95C—Ourimbah to Tuggerah
Central Coast	Feeder 951—Ourimbah to West Gosford
Central Coast	Feeder 958—Tuggerah to Gosford
Central Coast	Feeder 956—West Gosford to Gosford
Central Coast	Feeder 95E—Gosford to Somersby
Central Coast	Feeder 95Z—Somersby to Mt Colah
Central Coast	Ourimbah sub-transmission substation
Central Coast	Gosford sub-transmission substation
Central Coast	West Gosford zone substation
Central Coast	Somersby zone substation
Central Coast	Mt Colah switching station

ACCC's considerations

The ACCC reviewed the list of assets in table 2.1 and the Wyong and Charmhaven substations. It concluded that those assets appeared to meet the code definition of transmission assets. IPART and the ACCC agreed to exclude these assets ($81.9m) from the distribution RAB and include them in the transmission RAB as at 1 July 2004.

The increased transmission asset base also affects the net allocation of communications and non-system assets between the distribution and transmission asset bases. The impact of this is to increase the opening transmission RAB by a further $9.8m with a corresponding decrease in the opening distribution RAB at 1 July 2004.

The overall impact of the changes is an increase to the transmission RAB by $91.7m from 1 July 2004. This has the effect of increasing EnergyAustralia's proportion of transmission assets from approximately 10 to 12 per cent of its total network asset base.

2.5.3 Application of the regulatory test

In December 1999 the code required TNSPs to subject all augmentations to the regulatory test, which the ACCC promulgated at that time.

Prior to March 2002:

- clause 5.6.2(g) of the code required TNSPs to analyse options to address system limitations within regions to identify the one that satisfies the regulatory test
- clauses 5.6.5 and 5.6.6 of the code required TNSPs to apply the regulatory test to inter-regional augmentations and new interconnections.

The relevant provisions of the code were substantially revised in March 2002, when the Network and Distributed Resources code changes[21] were gazetted. This code change split network augmentations into two categories, either large (greater than $10m) or small (between $1m and $10m).

After March 2002:

- clause 5.6.2A(b)(5)(i) of the code requires a TNSP's Annual Planning Report to rank proposed new small augmentations in accordance with the principles in the regulatory test
- clause 5.6.6A(c) of the code requires a similar ranking to be undertaken for new small network assets not identified in the Annual Planning Report
- clause 5.6.5(b)(3) of the code requires a TNSP to rank the proposed new large assets against reasonable alternatives in accordance with the principles contained in the regulatory test.

In assessing the efficiency of EnergyAustralia's past capex the ACCC sought information from EnergyAustralia on its compliance with clause 5.6 of the code. Accordingly on 26 August 2003 the ACCC requested a copy of all regulatory test applications conducted by EnergyAustralia from 1 July 1999 including application notices, submissions and final reports.

To date, EnergyAustralia has provided two regulatory test applications to the ACCC: a combined application with TransGrid for the CBD project and the Green Square substation project.

ACCC's considerations

In its draft decision, the ACCC notes that the application of the regulatory test is a code requirement, although it is not a code requirement that the results of the regulatory test must be applied in setting a revenue cap. However the ACCC also notes that capital investments which are assessed using the regulatory test principles face a reduced risk of optimisation.

The ACCC notes that there were two projects not subjected to the regulatory test by EnergyAustralia which the ACCC considered should have been. These were Macquarie Park and Beresfield substations.

The ACCC wrote to NECA on 8 June 2004 in relation to EnergyAustralia's failure to apply the regulatory test to these projects.

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21 ACCC, Determination—Applications for Authorisation—Amendments to the National Electricity Code—Network and Distributed Resources, 13 February 2002.

In its letter to NECA the ACCC also noted that EnergyAustralia's annual planning report for 2003, the Annual Electricity System Development Review (AESDR)[22], did not appear to meet the requirements as set out in the code. Since then EnergyAustralia has provided annual planning reports for 2001, 2002 and 2004. The ACCC has not formed a view as to whether these documents have met the requirements of the code.

NECA has since accepted undertakings from EnergyAustralia to ensure its future compliance with clause 5.6 of the code.

2.5.4 Capital governance framework

In its application, EnergyAustralia states that its capital governance process provides continuous review and assurance that capital prudence and efficiency are being achieved. In addition, EnergyAustralia considers that it places great emphasis on the planning and project identification stage of the capital planning process, because assessment of customer needs and selection of the best ways to meet those needs exert the greatest leverage over customer value and cost.

EnergyAustralia states that it has made major improvements in the last two years at all levels of its capital investment process. EnergyAustralia states that it has been developing and implementing a new capital governance process since 2001. As a result of these changes, EnergyAustralia contends that its capital investment strategy is now designed to achieve specific outcomes at the lowest sustainable cost.

The ACCC's draft decision outlines EnergyAustralia's capital governance framework in detail.

Consultant's report

As part of its review of EnergyAustralia's revenue cap application, GHD conducted an expenditure related business systems review. The focus of the review was whether the systems and activities put in place by EnergyAustralia have delivered or will deliver the appropriate service levels in the most cost efficient manner. The review covered both historic and forecast expenditure.

GHD's conclusion is that EnergyAustralia started the 1999–2004 regulatory period with weak systems and data, which reduced its decision making capacity. Importantly, GHD found that EnergyAustralia's performance in this regard was below that expected of a prudent operator.

With regard to specific business systems, GHD made the following findings.

- *Efficiency of organisation structure*—GHD concluded that, in general, the information did not exist to enable it to say with complete assurance that EnergyAustralia's past expenditure has been appropriate, prudent and efficient. Further, reporting systems and decision making protocols that are clear and traceable and enable EnergyAustralia to link information to decision making are only now starting to be put into place. Finally, past systems and practices would

22 EnergyAustralia, Annual Electricity System Development Review, May 2003.

have restricted EnergyAustralia's business performance over the 1999–2004 regulatory period.

- *Efficiency of service/project delivery systems*—EnergyAustralia had reasonably poor systems and processes in place, and decisions made would have had a higher risk level due to the input of poorer quality data.

- *Overall asset management planning*—EnergyAustralia had relatively poor systems in place at the start of the 1999–2004 regulatory period. The implications of this would have been decision making based on inferior information, and the full ramifications of these decisions would not have been fully understood at the time. EnergyAustralia was lagging the industry in this regard. Finally, EnergyAustralia does not have a comprehensive document which outlines the asset management plan for the entire organisation.

Submissions

In response to the draft decision, EnergyAustralia states that its new governance procedures were never intended to apply in the 1999–2004 regulatory period. EnergyAustralia maintains that its intention is that all investment decisions made in the 2004–2009 regulatory period will be consistent with the new governance procedures.

EnergyAustralia acknowledges that these better systems will improve its ability to respond to information requests in a more timely fashion. However, it contends that the systems in place at the time of the 1999–2004 revenue cap decision were known to the ACCC and no requirements were imposed to improve these systems. Therefore, statements by the ACCC and GHD represent an ex post attempt to change the rules after investments were made.

EnergyAustralia argues that its past investment decisions have not been poor and that its systems and processes are not of a lower standard than those of other Australian TNSPs. EnergyAustralia also stresses that it is committed to improving its IT systems to ensure greater transparency of decision making and of asset information in the future.

ACCC's considerations

EnergyAustralia's capital governance process does not establish the prudence or efficiency of its capex decisions over the 1999–2004 regulatory period. However, the ACCC has concerns that EnergyAustralia's poor systems compromised its ability to make prudent and efficient capex decisions over this period. This in turn has implications for EnergyAustralia's ability to effectively manage its asset base, which is particularly important for companies which operate in capital intensive industries.

In addition, the lack of systems and processes has limited EnergyAustralia's ability to provide information to the ACCC. This is a significant issue given the ACCC's reliance on EnergyAustralia to provide information to justify its investment decisions.

The ACCC welcomes EnergyAustralia's commitment to develop and improve its capital governance processes. The ACCC expects that in the future EnergyAustralia will provide comprehensive documentation demonstrating that its investments have complied with the new governance process and the code.

2.6 ACCC's 1999–2004 revenue cap decision

The ACCC accepted the initial prudence of the forecast capex amounts included in EnergyAustralia's application and a total capex figure of $56.7m[23] was included in the 1999–2004 revenue cap decision. The allowance covered a small number of projects specified by EnergyAustralia. The ACCC noted that the projects would be rolled into the RAB at their anticipated commissioning dates.

EnergyAustralia claims that the ACCC made several errors in its summary of its capex allowance for the 1999–2004 regulatory period in its draft decision. In particular, the ACCC did not include an allowance for the Haymarket project and the substation replacement allowance was understated by $1m. The ACCC also excluded the Sydney central connections project from the 1999–2004 capex allowance as it was not to be commissioned until after 30 June 2004.

The ACCC has reviewed EnergyAustralia's claims but considers the substation replacement allowance included in the draft decision is correct. The amount referred to by EnergyAustralia comes from its 1999 submission not from the 1999–2004 revenue cap decision.

Table 2.2 outlines the projects included in the 1999–2004 revenue cap decision. The amounts are expressed in nominal terms and exclude interest during construction.

Table 2.2 EnergyAustralia's capex allowance 1999–2004

Project ($m nominal)	99–00	00–01	01–02	02–03	03–04	Total
Feeders 910 & 911	0.0	0.0	10.0	0.0	0.0	10.0
Tuggerah to Munmorah feeder	0.0	3.5	0.0	0.0	0.0	3.5
Gosford to Ourimbah feeder(a)	0.0	0.0	0.0	0.0	7.0	7.0
Other augmentation	0.2	0.2	0.1	0.2	0.2	0.9
Transmission mains refurbishment	2.0	3.2	6.7	7.1	5.9	24.9
Substation replacement	1.0	1.2	1.5	2.0	2.0	7.7
Total	**3.2**	**8.1**	**18.3**	**9.3**	**15.1**	**54.0**

Note: Numbers may not add due to rounding.

(a) While this project was included in the 1999–2004 revenue cap decision and built, it was included in IPART's regulatory accounts not the ACCC's. It is one of the assets changing classification (see section 3.6 more details).

23 This was the prudent amount of capex due to be commissioned, not necessarily that spent, over the 1999–2004 regulatory period.

2.6.1 Actual capital expenditure

EnergyAustralia's actual capex in the 1999–2004 regulatory period exceeds that allowed for in the 1999–2004 revenue cap decision. EnergyAustralia's application provided a limited explanation of this overspend.

When compiling its application for the 1999–2004 revenue cap decision, EnergyAustralia forecast that winter peak demand would grow by 1.5 per cent per annum, and summer peak demand would grow by 2.5 per cent per annum. In its 2004–2009 revenue cap application EnergyAustralia states peak demand growth was an average 2 per cent for winter and 3.5 per cent for summer over the 1999–2004 regulatory period.

EnergyAustralia states that this higher than forecast demand contributed to increased capex over the current regulatory period. This led to both new projects being built and the construction of other projects being accelerated.

EnergyAustralia's actual capex is broken down by project in table 2.3 below.

Table 2.3 EnergyAustralia's actual capex

Project ($m nominal)	99–00	00–01	01–02	02–03	03–04	Total
Augmentations						
CBD upgrade	0.0	0.0	14.5	26.3	19.3	60.1
Feeders 910 & 911	0.5	4.0	0.6	0.0	0.0	5.1
Tuggerah to Munmorah feeder	0.2	3.5	0.3	0.0	0.0	4.0
Macquarie Park substation	0.0	0.0	11.8	0.0	0.0	11.8
Beresfield substation	0.0	0.0	0.0	0.4	7.6	8.0
Sub-total	**0.7**	**7.5**	**27.2**	**26.7**	**26.9**	**89.0**
Replacement and refurbishment						
Undergrounding at Homebush	10.0	0.0	0.0	0.0	0.0	10.0
Green Square substation	0.0	0.0	0.2	0.2	2.0	2.5
Refurbishment and replacement	6.7	2.3	2.5	0.5	0.9	12.8
Sub-total	**16.7**	**2.3**	**2.7**	**0.7**	**2.9**	**25.3**
Non-system	4.7	1.8	4.4	3.1	3.6	17.6
Total	**22.1**	**11.6**	**34.3**	**30.5**	**33.4**	**131.9**

Note: Numbers may not add due to rounding.

The ACCC's assessment of these projects is set out in section 2.8 below.

EnergyAustralia has invested approximately $132m over the 1999–2004 regulatory period, almost $50m[24] more than included in the revenue cap decision.

The majority of this overspend is in relation to augmentations to the network. This overspend is the result of a combination of actual project costs exceeding estimates and projects being brought forward or new projects having to be built.

However EnergyAustralia underspent on its general replacement and refurbishment program. In the 1999–2004 decision the ACCC allowed $34m for replacement and refurbishment expenditure. This was the total amount that was requested by EnergyAustralia in its 1999–2004 application. During the period, however, its total expenditure on replacement and refurbishment was $25m.

2.7 Issues on the draft decision

2.7.1 Investment criteria used to demonstrate prudence

EnergyAustralia in its submission on the draft decision maintains that all its past capex was prudent, efficient and in the public interest and should be added in full to the RAB.

EnergyAustralia argues that the ACCC has not specified its criteria for establishing prudence prior to the commitment of capital. As a result, the ACCC is attempting to apply investment criteria after capital has been sunk. EnergyAustralia claims that in the absence of established criteria, EnergyAustralia has found it difficult to determine the information required by the ACCC.

EnergyAustralia claims that it has met all industry standards for its past investments. Therefore, it is incumbent on the ACCC to accept all of its past capex.

EnergyAustralia contends that the ACCC has taken a different approach in assessing the past capex of EnergyAustralia and TransGrid. EnergyAustralia notes that the ACCC has undertaken assessments at various levels of detail for TransGrid, while, for EnergyAustralia, the ACCC undertook an in-depth investigation of each project. It suggests that the detail required by the ACCC has gone beyond what would be expected by a regulator undertaking "light-handed" regulation.

EnergyAustralia has claimed that the ACCC forced GHD to release its final report prior to GHD assessing all of the information provided by EnergyAustralia.

ACCC's considerations

The ACCC's approach to the determination of what constitutes efficient and prudent investment was set out in the DRP. The ACCC's application of this approach was discussed in chapter 3.3 of the draft decision and in chapter 1.3 of this decision (see

24 The 1999 decision was based on a commissioning date approach and allowed $56m capex. The ACCC has calculated a comparable cash spend allowance of $80m over the 1999–2004 regulatory period.

also chapter 6 of the TransGrid final decision). In summary, this approach involves three steps:

1. assessing whether there is a justifiable need for the investment
2. assuming the need for an investment is recognised, assessing whether the TNSP proposed the most efficient investment to meet that need
3. assessing whether the project that was analysed as the most efficient was in fact developed and, if not, whether the difference reflects decisions that are consistent with good industry practice.

The investment criteria adopted by the ACCC in its assessment of the prudence of investments over the 1999–2004 regulatory period is consistent with criteria set out in the code, the DRP and the 1999–2004 revenue cap decision.

In assessing EnergyAustralia's past capex, the ACCC split projects between those included in the 1999–2004 revenue cap decision and those which were not. For those projects included in the 1999–2004 revenue cap decision, the ACCC did not conduct a detailed investigation of these projects. Rather, the review focussed on comparing the actual cost of the project to the allowance in the 1999–2004 revenue cap decision and the explanation for any variation in cost. For the other projects a detailed investigation was undertaken.

The ACCC rejects EnergyAustralia's claim that it forced GHD to release its report prior to GHD reviewing all available information. The release of GHD's report was a mutual decision between the ACCC and GHD. GHD's report incorporated all information provided to it within specified time limits. In fact, the ACCC extended GHD's report timetable by over three months to allow it to assess information provided by EnergyAustralia. The reasons GHD was unable to reach conclusions on the prudence of EnergyAustralia's past capex are clearly outlined in its report.

The ACCC considers that if all of EnergyAustralia's past capex met industry standards then it should have been a relatively straight forward task to demonstrate the prudence of its expenditure to GHD. However, based on the information provided to it, GHD was unable to reach conclusions on the prudence of any of EnergyAustralia's past capex.

2.7.2 Prudence adjustment

The draft decision made a prudence adjustment to those projects the ACCC considered were not completely prudent and efficient. This adjustment disallowed any foregone rate of return during construction on those projects.

This prudence adjustment amounted to $8.7m for the CBD upgrade, $3m for the Macquarie Park substation and $0.4m for the Beresfield substation. It should be noted that the supplementary draft decision allowed the actual capex for these projects to be rolled in the RAB.

Submissions

In its submission on the draft decision, EnergyAustralia opposed the adjustments made by the ACCC. It argues that the adjustments are an arbitrary penalty that creates a dangerous regulatory precedent. EnergyAustralia argues that the approach has no basis in economic theory and that the ACCC has not provided a basis on which to justify the adjustment. EnergyAustralia is concerned that this approach has been adopted without any direct relationship being developed between the penalty and the efficient level of expenditure.

Transend's submission also raises a number of concerns:

- GHD and the ACCC were unable to complete their ex post prudence assessment and this has compromised the consultation process.
- The ACCC must identify the inefficient expenditure rather than rely on arbitrary cuts. While Transend understands that it may be difficult to accurately assess the imprudent amount of a particular project, that assessment is preferable to arbitrary cuts based on a methodology that has not previously been discussed.
- The nature of the penalty (disallowing returns during construction) will distort future investment decisions. In particular, Transend argues that large projects with long construction periods will have larger penalties if any amount of capex is considered imprudent. Given that larger projects tend to be more complex and difficult to implement, the expected value of the penalty will be relatively high—thereby tending to discourage TNSPs from undertaking large projects.
- Transend would like to see a detailed explanation on how penalties for imprudent capex have been calculated. Transend also requests that the ACCC define any ambiguous terms.

The EMRF believes that the ACCC has been diligent in attempting to rationalise the capex claims from EnergyAustralia. However, due to the lack of evidence provided by EnergyAustralia, there remains doubt as to whether the amount of past capex proposed to be rolled into the opening RAB is overstated.

The EMRF supports the ACCC's decision to disallow any return on EnergyAustralia's investments where it could not be ascertained that the expenditure was prudent. However the EMRF argues further that only the prudent and efficient amount of expenditure should be included in the RAB. Therefore, it argues that for the ACCC to decide that the amount might be considered prudent and efficient by excluding the return on the capital is a fundamental failure of its regulatory responsibility to consumers.

The EMRF compares this process to the process used in the Murraylink decision, where the regulatory test was applied to Murraylink and the value given to the asset was substantially reduced. The EMRF argue that the ACCC should carry out a similarly rigorous prudence and efficiency examination of EnergyAustralia's past capex.

The EMRF goes on to state that the ACCC has had insufficient time to properly assess the legitimacy of the past capex and so has used an approach that significantly favours the businesses. It believes that the tactics used by EnergyAustralia to confuse the ACCC regarding past capex and so get the bulk of the over-run approved has worked and the ACCC must not simply give in to such practices.

The customers' group contends that given that the prudence/efficiency of a number of projects was not demonstrated, actual capex spent on these projects should also be reduced, rather than just disallowing the return on the investment. It argues that customers should not have to pay for the cost of poor investments.

ACCC's considerations

In the draft decision, the ACCC stated that disallowing a return on EnergyAustralia's investment in these projects during the period of construction reflects a balance between the interests of EnergyAustralia and its customers. In reaching its decision the ACCC recognised that EnergyAustralia has not demonstrated all of its capex to be efficient and prudent, but also recognised the need for EnergyAustralia to invest in its network.

While the ACCC has not been satisfied that the actual expenditure on at least one project was prudent, it does not necessarily follow that this investment should be excluded in its entirety. Even if EnergyAustralia should have identified and implemented an alternative option, there would still obviously be some capital cost to EnergyAustralia in doing so.

The problem facing the ACCC is in determining what the prudent investment should have been. This task is made more difficult where the original assessment of investment options by EnergyAustralia was inadequate. While the ACCC could attempt to undertake such an assessment (in effect, by re-creating the entire regulatory test analysis) the ACCC does not consider it feasible or appropriate to do so within the context of a revenue cap determination. The reasons for this are stated at pages 60 and 61 of the TransGrid draft decision.

The ACCC does not believe the approach outlined in the draft decision is arbitrary. It attempts to provide a return on EnergyAustralia's capital investment that is fair and reasonable in all the circumstances, including the prudence of its investment decisions. In assessing the prudence of past capex, the ACCC's goal is not to punish or penalise TNSPs for inefficient investment. Rather, the ACCC's goal is to ensure TNSPs are provided with a fair and reasonable rate of return on efficient investment, while at the same time ensuring that users are not required to pay for inefficient investment.

However, the ACCC acknowledges that the approach set out in the draft decision to determine a prudence adjustment involves a departure from the approach foreshadowed in the DRP (Statement S5.1). That is it involves adding capex that has not been shown to be prudent to the RAB.

The DRP does not bind the ACCC in the same way as the code and, subject to the requirements of procedural fairness, the ACCC can depart from it if it is necessary and appropriate to do so. However, the application of these principles, where it is feasible to do so, will generally encourage certainty and consistency in the outcome of regulatory processes. Accordingly, it is preferable to determine an adjustment to EnergyAustralia's RAB based on that part of its capital investment that is deemed prudent and to allow a return on that prudent investment. This requires the ACCC to determine the value of prudent capex.

A method for determining the value of prudent capex was proposed in chapter 7.3 of the Mountain Associates Report on the prudence of the MetroGrid project (attachment A to the TransGrid Draft Decision).[25] This report also sets out the basis of the ACCC's approach to the determination of what constitutes a prudent and efficient investment.

The ACCC has decided to adopt this approach in determining a prudence adjustment for the investment by EnergyAustralia and TransGrid in the joint MetroGrid project. The reasons for doing so and the application of this approach to EnergyAustralia's investment in the MetroGrid project is discussed in section 2.8.1 below.

2.8 Assessment of specific projects

2.8.1 MetroGrid project

The MetroGrid project is a joint project between TransGrid and EnergyAustralia. In the ACCC's draft decision it is referred to as the CBD upgrade, which is in fact a subset of the total MetroGrid project.

EnergyAustralia notes that the main driver for this project was expected load growth, which would have prevented its existing network from meeting the modified n-2 planning criteria. The modified n-2 approach allows for a simultaneous outage of cable 41 or 42 and any 132kV feeder or 330/132kV transformer supplying the CBD.

At the time of the 1999–2004 revenue cap decision, independent consultancy reviews were undertaken and found that the increased reliability of the modified n-2 approach is appropriate in the CBD. However the expenditure undertaken increased substantially from EnergyAustralia's and TransGrid's initial proposal.

Proposed project

Table 2.4 sets out the investment amount that EnergyAustralia and TransGrid proposed for the IPART and ACCC 1999–2004 revenue cap decisions.

In its 1999–2004 revenue cap decision the ACCC accepted the prudence of the entire amount of capex EnergyAustralia planned to spend over the 1999–2004 regulatory period, which included the Sydney central connections ($25m). As this was recognised on a commissioning date basis this was not allowed for in the revenue.

The ACCC understands that IPART did not specifically approve any individual capital projects, rather it allowed an overall distribution capital budget over the regulatory period.

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25 Mountain Associates, An assessment of the prudency of TransGrid's investment in the MetroGrid project, 14 April 2004.

Table 2.4 Forecast CBD expenditure for the 1999–2004 revenue cap decisions

Capex ($m 2003-04)	99–00	00–01	01–02	02–03	03–04	2004+	Total
Sydney central connections[(a)]	0.0	0.0	5.0	15.0	5.0	0.0	**25.0**
Broadway substation[(b)]	0.0	0.6	4.5	4.5	3.9	0.0	**13.5**
Taylor Square[(c)]	0.0	0.0	0.0	0.0	5.6	28.2	**33.8**
Sub-total	**0.0**	**0.6**	**4.5**	**4.5**	**9.5**	**28.2**	**72.3**

(a) Included in the ACCC 1999–2004 revenue cap decision for EnergyAustralia.

(b) Included in EnergyAustralia's submission for 1999 IPART decision.

(c) Not part of the 1999–2004 regulatory period.

Regulatory test

EnergyAustralia and TransGrid undertook a joint regulatory test assessment of the MetroGrid project in 1999–2000. In the initial assessments 14 options were analysed all of which met the reliability standard for Sydney's CBD. However no single option was least cost because the costs were sensitive to uncertain variables.

The final report on the regulatory test recommended that EnergyAustralia:

- progressively connect its 132kV system to the Haymarket 132kV busbar from March 2003
- commission a 132kV busbar at a new 132/11kV zone substation in Surry Hills by July 2003.

NERA's modelling of these options showed that EnergyAustralia's expenditure was $41.2m ($1999). This was related to the Broadway and Goulbourn Lane network option.

Actual project

EnergyAustralia's actual expenditure on the MetroGrid project is shown in table 3.5. The project that EnergyAustralia built includes a substation at Campbell Street, Surry Hills and 132 kV connections to TransGrid's new Haymarket substation.

Table 2.5 EnergyAustralia's Actual CBD project expenditure

Capex ($m 2003-04)	99–00	00–01	01–02	02–03	03–04	2004+[(c)]	Total
Transmission asset[(a)]	0.0	0.0	15.6	27.1	15.7	4.0	62.3
Joint tunnel[(b)]	0.0	0.0	0.0	0.0	5.4	0.0	5.4
Distribution expenditure[(b)]	0.0	0.7	3.8	9.6	8.5	4.0	26.6
Total	**0.0**	**0.7**	**19.4**	**36.7**	**29.6**	**8.0**	**94.3**

(a) EnergyAustralia's transmission expenditure in the CBD.

(b) EnergyAustralia's distribution expenditure in the CBD.

(c) Not part of the 1999–2004 regulatory period. EnergyAustralia's estimate at April 2004

EnergyAustralia's 2003 application

As part of its application EnergyAustralia submitted an SKM report on the prudence of its past capex. SKM's review was limited to reviewing the timing of the capex and the cost of the assets built. SKM did not review the alternatives that may have resulted in a lower cost solution.

SKM noted that the capex program had prudent timing but that some costs seemed high given the scope of the work.

SKM notes a total estimated cost of $94.8m[26], including the distribution component. SKM concludes that the timing and cost of this project were prudent and appropriate, given NERA's and IPART's reviews of the project. The ACCC has concerns about SKM's conclusion because the actual cost of the project had risen substantially since NERA's review.

The ACCC also questions SKM's conclusions that EnergyAustralia chose the most prudent and efficient option given SKM didn't undertake an examination of the alternatives and the costs and benefits associated with the alternatives.

Consultant's report

GHD concluded that no matter which overall option was selected under the regulatory test review, EnergyAustralia's component would still have had to establish a zone substation in the Surry Hills area.

While GHD noted that EnergyAustralia documented the regulatory test process well EnergyAustralia did not document the analysis that led to the altered final investment decision. GHD was unable to trace the cost increases from those initially allowed to the amount that satisfied the regulatory test and finally to the amount actually spent on the CBD upgrade.

GHD did not conclude that the entire project was prudent and efficient.

Submissions

In its submission EnergyAustralia raised two issues. First the ACCC's draft decision methodology to determine the amount of capex to be allowed in the RAB was arbitrary. Second that the specific cost increases mentioned in the draft decision are justified. EnergyAustralia engaged SKM to review the prudence of the specific increases and attached SKM's report to its submission.

ACCC's considerations

The ACCC's approach to determining what constitutes a prudent and efficient investment is set out in the draft decisions for EnergyAustralia and TransGrid and is discussed above.

In its draft decision the ACCC accepted that the joint regulatory test should provide the starting point to assess the prudence and efficiency of EnergyAustralia's

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26 SKM's estimate as at 2003 was different to that provided by EnergyAustralia in 2004 and shown in table 2.5.

component of the MetroGrid project, known as the CBD upgrade. The ACCC found that the need for a prudent investment had been justified and that there is justification to allow the costs examined under the regulatory test.

The ACCC expressed concerns with the actual investment undertaken because of the significant increase in costs. In the draft decision the ACCC was unable to determine that the specific scope and cost increases were prudent and efficient. The ACCC noted that the increases arose from moving the site from Goulbourn Lane to Campbell Street, higher actual costs than those estimated for the cable tunnels, and the cost of additional feeder bays. However, the ACCC stated that it required further information in order to understand the basis upon which the costs were estimated in the regulatory test report and to trace EnergyAustralia's process as these costs increased. The ACCC stated that this information would give it a basis to determine the prudence of the actual investment in the project.

In the draft decision, the ACCC also noted that the magnitude of the cost increase is significant enough to justify a review of the level of detail used in the initial regulatory test assessment. In response to the draft decision EnergyAustralia had SKM undertake a review of its participation in the MetroGrid project with reference to specific costs. The most significant cost increase identified by SKM was an 84 per cent increase in the cost of the 132kV connections.

In addition to the information provided by EnergyAustralia, SKM examined tunnelling costs around the world. It came to the view that the overall capex on the CBD upgrade appeared to be reasonable.

While the initial estimates were completely within the control of EnergyAustralia, SKM considered the actual cost increase to be prudent. This was because EnergyAustralia went to a competitive tender for over 80 per cent of the inputs to the CBD upgrade.

As the MetroGrid project is a joint project, it is relevant to consider the ACCC's findings in relation to TransGrid's investment in the MetroGrid project:

- The design and costing of possible network options for the purposes of the original regulatory test assessment of the MetroGrid project was inadequate. The original regulatory test assessment does not establish the prudence of the actual investment in the MetroGrid project.
- Approximately 12 to 18 months after the regulatory test assessment was completed (and before construction had commenced) TransGrid was aware that the estimated cost of the project would be approximately $227.5m, as opposed to the estimated cost of $142m at the time of the regulatory test assessment. At this time TransGrid should have reviewed the MetroGrid project to determine whether, under the principles in the regulatory test, this project was still the best option.
- In comparison to the revised project as at 2001, the option selected became the highest cost option when compared with the original regulatory test.

- There was no timing consideration that would have prevented deferring the implementation of the MetroGrid project long enough to review the decision to proceed with the MetroGrid project. By bringing forward investment in demand side management, TransGrid could have continued to meet the existing n-1 standard for a sufficient period of time to enable this review to occur.

Because of TransGrid's failure to review its decision to proceed with the MetroGrid project when it became aware of the changes to the design and cost of the project, the ACCC has concluded that TransGrid's actual investment in the MetroGrid project cannot be considered prudent.

As foreshadowed in the draft decision, the ACCC has reviewed EnergyAustralia's process as the costs of its investment in the MetroGrid project were increasing. The same criticism of TransGrid's process can also be made of EnergyAustralia.

As SKM noted in its review undertaken for EnergyAustralia:

> by 2001 EnergyAustralia was aware that the project costs would be substantially higher than its 1999 estimates, but did not conduct another regulatory test. While this is arguably not an ideal capital governance process…this does not in itself mean the implemented option was not optimal.[27]

While EnergyAustralia's exact cost estimate at 2001 is not known, SKM[28] noted GHD had advised EnergyAustralia that the cost of its cable tunnel would be approximately \$26m[29] in 1999 dollars, rather than the \$7.6m assumed during the original regulatory test analysis. GHD's advice was provided in a report dated 21 December 2000. This item alone increased the estimated cost of the project beyond the 40 per cent 'stress test' used in the original regulatory test assessment.

In the draft decision, the ACCC stated that a more detailed analysis during the original regulatory test may not have affected what EnergyAustralia would have had to build at this stage. However, as with TransGrid, a more detailed and thorough analysis of the design and costing of possible network options may, at the very least, have led to a change in the timing and order of investment options.

As in the case of TransGrid, the ACCC consider that EnergyAustralia could have deferred the implementation of the MetroGrid project long enough to review its decision to proceed with the MetroGrid project. There does not appear to have been a jurisdictional or code requirement for the implementation of a modified n-2 standard in any particular timeframe.

While the ACCC has accepted the need for prudent investment by EnergyAustralia, the implementation of a revised standard within any particular timeframe was not justified at any cost. By bringing forward investment in demand side management,

27 SKM, Review of Draft ACCC Determination re EnergyAustralia Transmission Projects, 1 July 2004, p.16.

28 ibid, p. 20.

29 The amount reported in December 2000 was \$28m, The ACCC adjusted this to compare in 1999 dollars.

TransGrid and EnergyAustralia could have ensured that the existing n-1 standard was met for a sufficient period of time to allow a review of the decision to proceed with the MetroGrid project. Accordingly, the ACCC finds that EnergyAustralia's investment in the MetroGrid project was not prudent.

Prudence adjustment

As noted in chapter 2.7.2 above, the ACCC will not apply the approach set out in the draft decision to determine the value of prudent capex with respect to EnergyAustralia's investment in the MetroGrid project. Instead, the ACCC will determine the value of prudent capex based on that part of EnergyAustralia's investment in the MetroGrid project that is deemed prudent and allow a return on that prudent investment.

As with TransGrid, the basis of the ACCC's conclusion on the prudence of the MetroGrid project is that EnergyAustralia failed to review its decision to proceed with the MetroGrid project once it was clear that the cost of the project would be well in excess of the estimates used for the original regulatory test assessment.

This leaves the ACCC with the task of determining an adjustment to EnergyAustralia's RAB for that part of the investment in this project that was not prudent. This task is made more difficult by the problems with the original regulatory test assessment and the fact that the decision to proceed with the MetroGrid project was not reviewed when the cost increases became known. While the ACCC could have attempted to undertake such an assessment (in effect, by re-creating the entire regulatory test analysis) the ACCC does not consider it feasible to do so within the context of a revenue cap determination.

An alternative method for determining the value of prudent capex was proposed in chapter 7.3 of the Mountain Associates Report[30] on TransGrid's investment in the MetroGrid project. When applied to both TransGrid and EnergyAustralia, this approach assumes that:

- once TransGrid and EnergyAustralia knew that the actual cost of the MetroGrid project was likely to substantially exceed the cost assumed for the original regulatory test assessment, they re-assessed the possible investment options through a further application of the regulatory test
- TransGrid and EnergyAustralia brought forward investment in demand side management envisaged after completion of the MetroGrid project, extending their networks' compliance with a n-1 standard and deferring the need to implement a modified n-2 standard for at least two years, thus enabling the regulatory test analysis to be repeated
- after a re-examination of network options through the regulatory test, the preferred option is still the MetroGrid project, with the design and cost anticipated in 2001.

30 op. cit.

On this basis, a prudence adjustment is determined by comparing the present cost of the MetroGrid project as envisaged during the original regulatory test analysis to the MetroGrid project as envisaged in 2001, with the investment in demand side management brought forward and the construction of the project deferred for two years.

The difference between the two represents the cost of TransGrid and EnergyAustralia's failure to respond to information showing they had under-estimated the cost of the MetroGrid project in the original regulatory test assessment. As such, this difference represents an estimate of the portion of the expenditure on MetroGrid project that was not prudent.

Using this approach, Mountain Associates determined a combined prudence adjustment for both TransGrid and EnergyAustralia of $36m in 1999 dollars, or $42.7m in 2004 dollars. When apportioned between TransGrid and EnergyAustralia, an amount of $32.8m should be excluded from TransGrid's RAB in 2004 and $9.9m from EnergyAustralia's RAB in 2004.

Subject to the modification explained below, the ACCC has decided to adopt this approach in determining a prudence adjustment for EnergyAustralia's investment in the MetroGrid project. The ACCC believes this is a logical and appropriate means of determining a prudent level of investment. While this may not have been the only option available to EnergyAustralia once it became apparent that the cost of the MetroGrid project had substantially increased, it is a feasible course of action that could have been undertaken by a prudent TNSP in EnergyAustralia's position at this time. It is a conservative approach that makes a number of assumptions favourable to EnergyAustralia, including the deferment of the implementation of a modified n-2 standard for no more than 2 years and the assumption that a further regulatory test assessment would result in the MetroGrid project (as envisaged in 2001) being ranked as the preferred option.

For the purpose of the analysis in the Mountain Associates Report, it was assumed that, in 2001 EnergyAustralia's cost had increased by the same proportion as TransGrid's. On this basis Mountain Associates assumed a revised cost to EnergyAustralia of $68m in 1999 dollars for the purposes of calculating a prudence adjustment.

The ACCC has decided to modify this aspect of the Mountain Associates approach for the purpose of determining a prudence adjustment for EnergyAustralia. While EnergyAustralia's exact cost estimate as at 2001 is not known, GHD had advised EnergyAustralia by this time that the cost of its cable tunnel would be approximately $26m[31] in 1999 dollars rather than the $7.6m assumed during the original regulatory test analysis. Further investigation could reveal that the estimated costs at this stage were even higher, however this has not been possible based on the information before the ACCC. The ACCC has therefore proceeded on the basis that the cable tunnel was the only cost increase known to EnergyAustralia at this time.

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31 This amount was reported in December 2000 as $28m, The ACCC adjusted this to compare in 1999 dollars.

On this basis, the ACCC has added a further $18.4m to the $41.2m assumed during the original regulatory test analysis. In applying the Mountain Associates approach, the ACCC will assume that, at the time of repeating the regulatory test analysis, the estimated cost of EnergyAustralia's component of the MetroGrid project would have been $59.6m in 1999 dollars.

After replacing the Mountain Associates assumption of $68m with $59.6m, the ACCC has determined that a combined prudence adjustment of $32.89m in 1999 dollars rather than $36m. Given the proportion of known costs at 2001, the ACCC has determined that approximately $6.8m in 1999 dollars represents the level of EnergyAustralia's investment in the MetroGrid project that was not prudent.

The imprudent cost increase identified was related to the cable tunnel and only 50 per cent of the tunnel was allocated to the transmission RAB. Therefore the ACCC considers that only 50 per cent of the $6.8m should be removed from the transmission RAB. Accordingly, the ACCC determines that an amount of approximately $3.4m in 1999 dollars should be excluded from EnergyAustralia's RAB on the basis that it represents the investment in the MetroGrid project that was not prudent. This equates to a $4.0m reduction in the RAB as at 1 July 2004

2.8.2 Feeders 910 and 911

EnergyAustralia proposed that $10m be included in the 1999–2004 revenue cap to increase the rating of feeders 910 and 911 running from Sydney South to Chullora. The ACCC accepted the initial prudence of this project and included an allowance of $10m in the 1999–2004 revenue cap decision. This project was completed in October 2001 at a cost of $5.1m (1999 dollars).

As part of this project, EnergyAustralia replaced the conductors on about 15 kilometres of double circuit transmission line and undertook the structural reinforcement of towers. It provides an additional 100 megawatts (MW) of capacity during normal system conditions, rising to 160 MW when TransGrid's 330 kV cable from Sydney South to Beaconsfield (cable 41) is out of service.

This project is an augmentation to the network. EnergyAustralia states that the main driver for this project was the loading on the interconnected system supplying the CBD. EnergyAustralia states that this project assisted in deferring expenditure on a new 330 kV supply point into the CBD.

EnergyAustralia utilised an n-1 reliability criterion in its planning for this project. With cable 41 out of service the loading on feeders 910 and 911 exceeds their firm capacity.

In its initial planning stage for this project, EnergyAustralia identified three options to address the loading issues on the Beaconsfield West substation. EnergyAustralia considered that increasing the rating of feeders 910 and 911 as the most cost effective solution.

Consultant's report

On the basis of the load flow data and loading details provided by EnergyAustralia, GHD concluded that the issues identified in relation to the relief of Beaconsfield West and ultimately supply to the CBD are valid and that technically the project was an appropriate option to address those issues.

GHD also concluded that the option of replacing conductors on feeders 910 and 911 appears to be prudent from a technical perspective and that the project provided a cost effective option for the deferral of expenditure by TransGrid.

GHD could not conclude that the investment as a whole was prudent because it did not have sufficient information on the costs for this project compared to other options considered.

ACCC's considerations

Based on additional information provided by EnergyAustralia, the ACCC considers that this project is a prudent investment and $5.1m (1999 dollars) has been included in the opening RAB in relation to this project.

2.8.3 Tuggerah to Munmorah feeder

EnergyAustralia proposed that $3.5m be included in the 1999–2004 revenue cap for a feeder between Tuggerah and Munmorah. The ACCC accepted the initial prudence of the feeder between Tuggerah and Munmorah and included an allowance of $3.5m in the 1999–2004 revenue cap decision. The feeder was completed in 2001 at a cost of $4m (1999 dollars).

While not included in the ACCC's 1999–2004 revenue cap decision, a related project is the construction of two substations at Wyong and Charmhaven which are connected to the new feeder from Tuggerah to Munmorah. EnergyAustralia states that $18m was included for the construction of the two substations in EnergyAustralia's distribution capital allowance as part of IPART's 1999 determination. The conversion of the two zone substations was also completed in 2001 and cost approximately $19.7m in 1999 dollars.

The Wyong and Charmhaven substations are two of the assets that EnergyAustralia is claiming to now meet the code definition of transmission assets and is seeking to include in the transmission RAB (see section 2.5.2). While the construction of these two substations is analysed as part of the review of the feeder from Tuggerah to Munmorah, the discussion below mainly refers to the feeder project.

The feeder project

The feeder is an augmentation to the network which EnergyAustralia states was required to overcome excess electricity loads and improve system reliability in the Wyong and Charmhaven area. EnergyAustralia goes on to state that this project was required to improve reliability, reduce network losses, retire ageing assets, and cater for high demand growth. The peak loading on the existing 33 kV system was in excess of firm ratings and there was a risk of load shedding for any equipment failure. EnergyAustralia adopted an n-1 reliability planning criterion for the feeder augmentation.

Construction of Charmhaven and Wyong zone substations

The construction of the two substations is an augmentation to the network. EnergyAustralia states that the major drivers for the project were the loadings on:

- the Charmhaven zone substation, which exceeded its firm capacity by 1996
- the Wyong zone substation, which exceeded its firm capacity by 2000.

As with all zone substations, EnergyAustralia utilises an n-1 planning criterion and risk analysis to determine when an augmentation is required. In the case of the Charmhaven and Wyong zone substations, a risk assessment allowed this project to be deferred until 2001, including the construction of the feeder.

EnergyAustralia also states that the entire project provided for the deferral of approximately $22m in expenditure by TransGrid. This deferral, but not cost, is stated in the joint EnergyAustralia and TransGrid regulatory test.[32]

In its initial planning stage, EnergyAustralia identified a number of potential options to address the loading issues in the Wyong and Charmhaven area. EnergyAustralia states that on a least cost basis, the chosen option was substantially cheaper. EnergyAustralia states that it has analysed non-network solutions including demand management but these were not viable.

Consultant's report

GHD has reviewed the information provided by EnergyAustralia and concluded that:

- the forecast loads exceeded firm ratings at the Wyong and Charmhaven zone substations
- loadings on the interconnected systems and bulk supply points support the justification for the conversion of the Charmhaven zone substation to 132 kV
- the 132 kV interconnection between Tuggerah and Munmorah was a strategic solution to providing relief to the Munmorah bulk supply point and Ourimbah sub-transmission substation.

GHD is unable to determine if the magnitude of the investment was prudent due to a lack of information on how the costs of the project moved from its initial planning stage to board approval and ultimately the 1999 submission to the ACCC. GHD noted that the final cost of the feeder from Tuggerah to Munmorah exceeded the ACCC allowance by approximately 10 per cent.

Overall, GHD concluded that there was a need for a solution to address the load constraints identified by EnergyAustralia and that the project built will address that need. However, GHD was unable to determine if the magnitude of the expenditure was prudent due to a lack of information.

32 EnergyAustralia and TransGrid, Development of Electricity Supply to the Central Coast Final Report, March 2003.

ACCC's considerations

Based on the additional information provided by EnergyAustralia, the ACCC considers that this project is a prudent investment and hence $4m in 1999 dollars has been included in the opening RAB in relation to this project.

With regard to the two zone substations at Wyong and Charmhaven, their full value will be rolled into the opening RAB at 1 July 2004 (see section 2.5.2 for more detail).

2.8.4 Macquarie Park substation

The Macquarie Park substation project was not included in EnergyAustralia's submission to the ACCC in 1999. However, EnergyAustralia states that the construction of a zone substation was included in its 1997 distribution application to IPART and that an allowance of $10m was provided for the construction of a new 132/11kV zone substation at Macquarie Park in 2004–05. The Macquarie Park substation was completed in 2001 at a cost of $11.8m.

This project is an augmentation to the network. EnergyAustralia states that this project was required to accommodate significant load growth in the Macquarie Park area during the 1999–2004 regulatory period. In particular, the loadings on the Epping and North Ryde zone substations exceeded their firm capacities by the summer of 2000.

EnergyAustralia utilised an n-1 planning criterion for this zone substation. However, if a zone substation is loaded above its firm rating, EnergyAustralia carries out a risk assessment to determine whether augmentation is required or can be deferred.

For the Epping and North Ryde zone substations, EnergyAustralia conducted risk assessments for summer 2000 and 2001. Both substations exceeded the risk assessment criteria for the summer of 2001. Therefore, EnergyAustralia brought forward the completion of the project from 2004–05.

EnergyAustralia contends that the earlier completion of the project was due to ongoing high load growth and two specific projects:

- the Parramatta to Chatswood rail link
- connecting Exodus, a data warehouse company, to the network.

EnergyAustralia states that it has instigated demand management initiatives via an expression of interest which, given the load growth forecast at the time, identified some practical options that would have provided for a short deferral of the project. However, the high energy usage of the forecast projects outstripped the capability of the identified demand management alternatives.

Consultant's report

GHD concludes that EnergyAustralia has demonstrated the technical justification for the project including:

- the proximity of the site to existing 132 kV lines

- load growth in the area

- that a standard 132/11 kV zone substation would have an ultimate capacity to accommodate the forecast loads, compared with 33/11 kV or 66/11 kV design.

However, GHD is unable to reach a conclusion on the prudency of the project as it has not been provided with any detailed information on project costs and the analysis of options considered to meet the need for the investment.

Submissions

EnergyAustralia submitted additional information; including, a report by SKM, which it argues demonstrates the prudence of the Macquarie Park project. This additional information compares the cost of the Macquarie Park project to 5 alternatives to demonstrate that it was the least cost solution. In its report, SKM notes that it considers the costs for the Macquarie Park project are likely to be efficient. It found that the project selected was the least cost option from six alternatives and the costs compared favourably with benchmarked industry costs.

EnergyAustralia also states that only allowing the capex to be rolled into the RAB, without the inclusion of a capitalised foregone rate of return on the over spent amount, is inappropriate because the code requires the ACCC to allow a reasonable rate of return on efficient capex.

ACCC's considerations

The ACCC has been provided with the value management (VM) study for this project which was conducted in September 1998 and recommended, as its preferred option, a new substation being commissioned in Macquarie Park in 2005. EnergyAustralia has also provided risk assessments which demonstrate that the substations at Epping and North Ryde exceeded risk assessment criteria. The ACCC has also been provided with a demand management paper for the area and a project brief with high level cost estimates.

EnergyAustralia has explained that the project was brought forward from 2005 to 2001 as a result of the Parramatta to Chatswood rail link and Exodus.

As this project was not included in the 1999–2004 revenue cap decision, and in the absence of any regulatory test (or similar) assessment, the ACCC has endeavoured to utilise the following principles in determining the efficiency of the project:

- Was the project required?

- Were the timing and costs appropriate?

- Was the option that was built, the most efficient means to address the problem?

The ACCC concurs with GHD's assessment that EnergyAustralia has provided technical justification and the project costs are appropriate.

However, at the time of the draft decision the ACCC had not been provided with a regulatory test application or any other economic analysis which demonstrates that the

Macquarie Park zone substation was the most efficient option to address the issues in the area. A project such as this would only satisfy the regulatory test or the prudence test if it was the least cost project to address the network limitation that had been identified. Consistent with the requirements of the code, the ACCC does not believe that an investment should be rolled into the RAB unless it is satisfied that this is the case.

In response to the draft decision EnergyAustralia provided an economic assessment to show that the selected option was a least cost option. This assessment showed that EnergyAustralia had constructed a least cost option given the committed loads that did not proceed and other load growth that eventuated.

That is EnergyAustralia decided to bring forward the timing of construction of the Macquarie Park substation to meet large committed load. Although this load did not proceed with connection other load growth in the area meant that the need for the Macquarie Park substation was justified anyway.

Specifically the load EnergyAustralia forecast for 2005 in 1998 was 118MVA. This amounted of load eventuated by 2000. Therefore the load problems expected for 2005 at North Ryde and Epping were arising in 2000.

The draft decision expressed a concern that EnergyAustralia had not met its code obligations in undertaking a regulatory test assessment. EnergyAustralia considers that the ACCC had misinterpreted the code in this regard. The ACCC still considers the code obligations were not met. However the ACCC does not currently have any powers to enforce the code and therefore wrote to NECA to request that it investigate this matter.

The ACCC understands that the outcome of this investigation was that NECA accepted an undertaking from EnergyAustralia to ensure future code compliance in this regard. It is not within the ACCC's role as economic regulator to set penalties for breaches to the code and as such is satisfied that this matter has been dealt with.

The ACCC considers the economic assessment provided is sufficient to show that the Macquarie Park substation capex was efficient. Therefore this decision includes the full $11.8m (1999 dollars) in the regulatory asset base and will allow the return on investment during construction.

2.8.5 Beresfield substation

EnergyAustralia commenced construction of a new 132/33kV sub-transmission substation at Beresfield in the 1999–2004 regulatory period. However, the project will not be completed until part way through the 2004–2009 regulatory period. The Beresfield sub-transmission substation project was not included in the 1999–2004 revenue cap decision.

EnergyAustralia states that this substation forms a critical part of its development strategy in the Tarro-East Maitland region of the Hunter Valley. The overall strategy involves the augmentations to the transmission and distribution systems to meet increasing loads in the surrounding regions.

Currently the area is serviced by two zone substations at East Maitland and Tarro. The loading on both these substations is currently exceeding their firm capacities. Similarly the loading on two nearby sub-transmission substations at Kurri Kurri and Tomago also exceed or will soon exceed their firm ratings.

EnergyAustralia contend that the construction of a 132/33 kV sub-transmission substation was the least cost feasible solution to the load issues in the area.

Consultant's report

GHD notes that while it was provided with various planning reports that identified a large number of options and arrived at recommended capital projects that overcome short and long term limitations in supplying load in the area, there was a lack of rigour in the cost estimates provided to GHD.

GHD also found no evidence that the Beresfield project had been formally subjected to EnergyAustralia's new capital governance process.

Overall, GHD is unable to give an opinion on whether the expenditure is prudent.

Submissions

In response to the ACCC draft decision EnergyAustralia submitted additional information to the ACCC. This additional information consisted of:

- SKM's independent review of the project
- a report which outlined an assessment of the project consistent with the principles of the regulatory test.

The SKM report found that the option developed by EnergyAustralia was the least cost option of the three logical solutions. Further, that at each stage of project authorisation EnergyAustralia reviewed the costs to validate its preferred option. SKM's report notes that the Beresfield project was a 'model case study for the corporate governance of capital works projects'.

EnergyAustralia has submitted a report which assesses the Beresfield project consistent with the principles contained in the regulatory test. This document indicates that the project developed was the least cost option to address the loading issues in the Tarro-East Maitland area.

ACCC's considerations

In the draft decision, the ACCC noted that it had not been provided with a regulatory test application which demonstrated that the Beresfield sub-transmission substation was the most efficient option to address the issues in the area. Rather, the only analysis EnergyAustralia had provided to the ACCC on the options considered in meeting the need were outlined in a number of internal planning reports. The planning reports did not provide sufficient details on the costings of all the options identified as per the regulatory test principles. The ACCC also noted that EnergyAustralia had failed to publicly consult on this project to ascertain if any further options to address the need were available.

Therefore, in the draft decision the ACCC found that it was unable to determine that the Beresfield project was an efficient investment. Consistent with those other projects where it was unable to identify an efficient level of expenditure, the ACCC proposed to disallow any return on EnergyAustralia's investment during the period of construction.

For the final decision the ACCC has taken into consideration the additional information provided by EnergyAustralia; in particular, the report assessing the project against the principles outlined in the regulatory test and SKM's findings. While the ACCC considers that one of the key objectives of the regulatory test principles is to provide for public consultation and comment on augmentations to the network, the documentation supplied by EnergyAustralia demonstrates the need for the project and that the project implemented was the least cost solution.

The ACCC's decision is to allow $8m (1999 dollars) to be rolled into the RAB in recognition of EnergyAustralia's expenditure on this project over the 1999–2004 regulatory period. The ACCC will also allow the foregone rate of return on EnergyAustralia's investment to be rolled into the RAB.

2.8.6 Undergrounding transmission mains at Homebush

The undergrounding of transmission mains at Homebush was not included in the 1999–2004 revenue cap decision. EnergyAustralia states that its component of the costs of this project was $10m (1999 dollars).

The ACCC has been provided with an extract of an implementation agreement between the Olympic Co-Ordination Authority (OCA) and EnergyAustralia for the relocation of an overhead transmission system and the construction of an underground transmission system in the Homebush Bay Development area. EnergyAustralia has also provided a construction contract for this project with a total cost of $37m. EnergyAustralia states that it contributed $10m to this project with the remainder paid by the Sydney Organising Committee for the Olympic Games and the OCA.

Consultant's report

GHD was not asked to review this project.

Submissions

In its submission on the draft decision, EnergyAustralia notes the project was not necessary for electrical/network reasons and delivers little benefit to consumers during the period of the remaining lives of the overheard lines that were replaced.

However, EnergyAustralia notes that some of these lines were apparently in poor condition and may have needed replacing by around 2005, with others expected to remain serviceable until 2015.

EnergyAustralia contends that it is reasonable that the depreciated cost of the new underground assets be included in its RAB from the date the old assets would have needed replacing. Therefore, EnergyAustralia is seeking 15 per cent of its costs (depreciated by 6 years) be included in the RAB now, with the remaining 85 per cent included in 2015 (depreciated by 17 years).

In its report on the Homebush project, SKM notes that it was not required for network reasons and customers should not fund the costs of undergrounding while the existing assets would have remained serviceable. Rather than conclude that some of the existing lines were in poor condition, SKM merely notes that EnergyAustralia estimated that one of the three tower lines would have required replacement in 2005, with the remaining two requiring replacement in around 2015.

SKM go on to note that it would be appropriate to consider whether new overhead lines would have been a viable and cheaper option to undergrounding, and EnergyAustralia received benefits in-kind (Olympic partner status) in return for its $10m cash contribution.

ACCC's considerations

Following from its draft decision, the ACCC sought additional information from EnergyAustralia; including:

- why the project was required
- the specific assets built
- what specific assets comprised the $10m claimed to have been EnergyAustralia's expenditure
- why EnergyAustralia contributed $10m
- any economic analysis which demonstrates that this project was the least cost option to address the need.

In response to EnergyAustralia's submission on the draft decision, the ACCC sought additional information on this project, including:

- an explanation of why the assets would have needed replacing before the end of their standard lives when EnergyAustralia has indicated that only one of the three lines were in poor condition. The ACCC requested condition based assessments to support EnergyAustralia's claims that these assets need replacing well before their standard lives
- clarification on the classification of the line that EnergyAustralia claims needed replacing in 2003 (feeders 200 and 201) as they are included in EnergyAustralia's distribution asset base. EnergyAustralia notes that the configuration of the system was unchanged as a result of the undergrounding so the assets should remain classified as being distribution assets.

EnergyAustralia is currently unable to provide any condition based assessment for the Homebush project. EnergyAustralia is no longer seeking to include any expenditure on feeders 200 and 201 in the RAB but will provide depreciated values for the remaining feeders prior to 2015. Therefore, no expenditure on this project has been included in the RAB.

2.8.7 Green Square substation

The construction of a new 132/11kV zone substation at Green Square commenced in the 1999–2004 regulatory period. However, the project will not be completed until part way through the 2004–2009 regulatory period.

Consultant's report

PB Associates reviewed this project in the context of EnergyAustralia's revised capex application (see chapter 3). It concluded that a reasonable amount of information had been provided and that the alternatives had been worked through. EnergyAustralia has also completed a regulatory test assessment of this project.

ACCC's considerations

In the draft decision the ACCC provisionally allowed this capex in the RAB on the basis that some outstanding issues could be resolved. EnergyAustralia started construction of the Green Square substation in the 1999–2004 regulatory period and will complete it in the 2004–2009 period.

In relation to the capex incurred over the 1999–2004 regulatory period, the ACCC considers that the full amount ($2.5m – 1999 dollars) proposed by EnergyAustralia should be included in the RAB. The ACCC is satisfied with the information provided that showed EnergyAustralia had undertaken an economic assessment and applied the regulatory test.

In the supplementary draft decision the ACCC included the full amount of $19m (2004 dollars) proposed by EnergyAustralia in the future capex. The ACCC has no reason to consider this expenditure imprudent and maintains the position it held in the supplementary draft decision. The ACCC has included $19m in the forecast capex for this project.

2.8.8 Replacement and refurbishment program

The ACCC allowed $33m in the 1999–2004 revenue cap decision for replacement of transmission mains and substations. EnergyAustralia has spent nearly $13m over the 1999–2004 regulatory period on its general replacement and refurbishment program, resulting in an underspend of approximately $20m.

Consultant's report

GHD concluded that insufficient information was provided on these items to enable any reasonable conclusions to be drawn on the efficiency of the replacement and refurbishment program.

ACCC's considerations

The ACCC has included $12.9m (1999 dollars) in the asset base for EnergyAustralia's past capex for its general replacement and refurbishment program, and oil containment and environment programs.

2.8.9 Non-system capex

The 1999–2004 revenue cap decision did not include an allowance for non-system capex. EnergyAustralia has spent approximately $17.7m (1999 dollars) on non-system capex during the 1999–2004 regulatory period. Non-system capex includes expenditure on IT systems, vehicles and plant, office equipment, land and buildings.

Consultant's report

GHD was not asked to review this expenditure.

ACCC's considerations

The ACCC has included the full $17.7m (1999 dollars) in the RAB for non-system capex.

2.8.10 Gosford to Ourimbah feeder

EnergyAustralia proposed that $7m be included in the 1999–2004 revenue cap to construct a feeder between Gosford and Ourimbah. The ACCC accepted the initial prudence of this project and included an allowance of $7m in the 1999–2004 revenue cap decision. The construction of the feeder has commenced but is yet to be completed. It is now estimated to cost around $12m.

While not included in the ACCC's 1999–2004 revenue cap decision, a related project is the conversion of the West Gosford zone substation which is connected to the Gosford to Ourimbah feeder. EnergyAustralia states that around $9.5m was included in EnergyAustralia's distribution capital allowance as part of IPART's 1999 determination for the conversion of the Lisarow zone substation. This was subsequently changed to the conversion of the West Gosford zone substation. The conversion of the West Gosford zone substation has commenced but is also yet to be completed. It is now estimated to cost around $12m.

Consultant's report

GHD was not asked to review this project.

Submissions

In response to the draft decision, EnergyAustralia submitted additional information of the final costs of the Gosford to Ourimbah feeder and West Gosford zone substation.

With regard to the Gosford to Ourimbah feeder project, EnergyAustralia contends that the comparison should be between the 1999 submission estimate inflated to 2003–04 dollars ($7.9m) and the final cost ($12.5m), a $4.6m variation.

EnergyAustralia states that the estimated cost was based on the conversion of the existing 33 kV line to 132 kV operation and that the total line length would be overhead. As a result of the community consultation process and associated environmental concerns, costs increased because:

- 25 per cent longer line length was required
- some undergrounding was required

- there were additional costs of the consultation process.

For the West Gosford zone substation, EnergyAustralia stated that the $9.5m allowed for in IPART's 1999 determination was in 1998 dollars and that the equivalent amount in 2003–04 dollars would be $11.1m. The remaining difference was explained by the change of site of the substation from Lisarow to West Gosford.

ACCC's considerations

EnergyAustralia has informed the ACCC that at the time of its application to the ACCC in 1999 this project was classified as being a transmission project. However, subsequent to the 1999–2004 revenue cap decision being made it was realised that the feeder connected two parts of EnergyAustralia's distribution network. Hence, the feeder should not have been included in the 1999–2004 revenue cap decision as a transmission project and it was subsequently excluded from the ACCC's regulatory accounts and included in IPART's regulatory accounts.

Over the course of the 1999–2004 regulatory period, the configuration of EnergyAustralia's network on the central coast has changed. As a result, the Ourimbah to Gosford feeder and the West Gosford zone substation now meet the definition of transmission assets. The Gosford to Ourimbah feeder and the West Gosford zone substation are two of the assets changing classification from 1 July 2004 (see section 2.5.2).

Both of these projects were included in 1999–2004 transmission and distribution decisions. Therefore, both the ACCC and IPART accepted the initial prudence of the projects.

In the draft decision, the ACCC stated that it considered that these investments appeared to be prudent but was reserving its judgement until EnergyAustralia provided an adequate explanation of the cost overruns on these two projects. For the purposes of the draft decision, the ACCC provisionally allowed the total actual expenditure to date to be rolled into the opening RAB, noting that in finalising its decision it would be seeking information from EnergyAustralia to justify the final costs of the feeder and substation. The explanations provided by EnergyAustralia have satisfied the ACCC that the increased expenditure was prudent. Therefore the ACCC has allowed the actual capex of $12m (1999 dollars) in the revenue cap.

2.9 ACCC's decision

With respect to past capex, the ACCC's decision is to allow $124.7m (1999 dollars) to be rolled into the opening RAB. In addition to including the actual capex from 1999–2004 this decision includes the capitalised foregone return on the overspent amount for all capex.

In accordance with the ACCC's roll-forward methodology the ACCC's decision is that the opening RAB for the 2004–2009 regulatory period is $635.6m (2004 dollars). The RAB calculations are set out below in table 2.6. This is a substantial increase of approximately 39 per cent on the opening RAB for the 1999–2004 revenue cap. This increase is the result of:

- a substantial capital overspend ($64.0m) from the 1999–2004 revenue cap decision

- assets changing classification ($91.7m). The impact of the assets changing classification contributes 44 per cent to the increase in the opening RAB and excluding its impact would result in an increase of only 16 per cent.

Table 2.6 EnergyAustralia's RAB

	99–00	**00–01**	**00–02**	**02–03**	**03–04**
Opening asset base	457.4	450.7	462.6	470.3	469.7
1999 decision capex at actual CPI	3.4	9.2	19.5	9.9	15.9
CPI adjustment	12.8	27.0	13.6	16.2	9.3
Depreciation[(a)]	-22.8	-24.3	-25.4	-26.7	-25.1
Closing asset base	450.7	462.6	470.3	469.7	469.7
add: capex not forecast over 1999–2004					64.0
add: assets changing classification over 1999–2004					91.7
add: return on overspend					10.2
Opening RAB 1 July 2004					635.6

Note: Numbers may not add due to rounding.
(a) Adjusted for actual inflation.

The roll forward methodology adopted by the ACCC in its modelling of the revenue cap means the closing balance of the asset base for one year becomes the opening balance for the subsequent year.

3 Forecast capital expenditure

3.1 Introduction

The objective of this chapter is to determine the amount of capex to be rolled into the asset base for the purpose of setting EnergyAustralia's revenue for this regulatory period. Chapter 2 determines the value of the opening RAB as at 1 July 2004. As was the case with determining the opening RAB, the forecast capex is a part of the calculation of the return on capital and return of capital.

As part of the SRP the ACCC has developed an ex ante framework. As this new framework was developed after EnergyAustralia's initial application, EnergyAustralia submitted a supplementary capex application in line with the ex ante framework.

This chapter sets out the:

- code requirements
- regulatory principles
- capital governance framework
- replacement capex
- augmentation capex
- compliance capex
- non-system capex
- ACCC's considerations
- ACCC's decision.

3.2 Code requirements

The ACCC sets the maximum revenue that TNSPs can recover from customers. Chapter 6 of the code provides a broad set of objectives that the ACCC must aim to achieve when setting revenue caps.

For EnergyAustralia's forward capex, part B of chapter 6 of the code requires the following:

- in setting the revenue cap the ACCC must have regard to the potential for efficiency gains in expected operating, maintenance and capital costs, taking into account the expected demand growth and service standards

- the regulatory regime must seek to achieve efficiency in the use of existing infrastructure, efficient operating and maintenance practices and an efficient level of investment

- the regulatory regime must foster an efficient level of investment within the transmission sector and the sectors upstream and downstream of it

- a revenue cap to be set for a period of no less than five years.

3.3 Regulatory principles

The ACCC has set out its method for setting revenue caps in its SRP. The SRP outlines a new approach to reviewing the TNSPs proposed capex, referred to as the ex ante framework.

The ex ante framework involves the ACCC setting a revenue cap based on a firm ex ante capex allowance at the start of the regulatory period to enable the TNSP to decide what investments it will make within the allowance.

The objectives of the ex ante allowance are to give TNSPs certainty and to improve incentives for efficient investment. To achieve these objectives the ex ante allowance needs to be aligned with efficient capex over the period, which in turn requires a critical analysis of a TNSP's forecast capex at the beginning of each regulatory period.

The ex ante allowance is expressed as a profile of annual capex for the regulatory period. The profile of capex and the opening RAB are used to determine the TNSP's return of, and return on, its assets over the regulatory period. This information together with other inputs such as opex and the WACC are used to calculate the TNSP's AR for each year of the regulatory period.

The RAB at the end of the regulatory period will be set based on the opening RAB and the rolled forward value of the depreciated actual capex. This is regardless of whether the sum of the actual capex is more or less than the sum of the ex ante allowance.

The effect of this arrangement is that if a TNSP spends less (more) than its ex ante capex allowance it benefits (loses) by the amount of the return on, and of, the underspent (overspent) amount for the remainder of the regulatory period.

This ensures that TNSPs prepare detailed capex forecasts when making their revenue cap applications to the ACCC, hence providing increased transparency. More importantly it also gives TNSPs incentives to spend efficiently.

However, the ex ante allowance relies on capex forecasts, which are inherently uncertain. The ACCC has recognised that large uncertainties may exist and has proposed to deal with the large uncertainties using two other mechanisms. These are:

- contingent (excluded) projects

- revenue cap reopener events.

3.3.1 Contingent projects

In response to the supplementary draft decision interested parties expressed confusion about the term 'excluded project'. The term was intended to refer to a list of capex projects that were to be excluded from the ex ante capex allowance but which would be included in the TNSPs overall capex allowance following an assessment by the ACCC. Some interested parties were concerned that it meant the list of capex projects were to be completely excluded from the revenue cap.

With the aim of improving the understanding of this mechanism the ACCC has revised its terminology. Excluded projects will be now referred to as contingent projects.

An allowance for investment in these projects will be added to the TNSP's RAB, contingent upon certain trigger events and the ACCC undertaking an ex ante review of the projects.

Capex would not be considered under the ex ante capex allowance if it is significant but uncertain. The test for this is that putting the capex in the ex ante allowance could lead to a significant error in that allowance.

If a contingent project is triggered in the regulatory period the ACCC would review the project and set an ex ante allowance for that particular project.

The ex ante allowance would be applied for a five year period. The commencement date of the five year period would be determined when the ACCC assesses the contingent project.

At the end of the five years the depreciated value of the actual capex of the contingent project will be included in the RAB, subject to the capex complying with the requirements of the code.

In order to adjust the revenue stream within a regulatory period as a result of a contingent project a code change would be necessary. In the absence of a code change the revenue adjustment will be made on a NPV neutral basis at the end of the relevant regulatory period. This process is described in greater detail in appendix B to this decision.

For the remainder of this document, any reference to contingent projects includes projects proposed as excluded projects by EnergyAustralia.

3.4 Capital governance framework

In July 2004, EnergyAustralia implemented a new capital investment framework by which investment decisions are evaluated and funded. The capital governance framework was discussed in detail in the ACCC's draft and supplementary draft decisions.

While new projects fall under this framework, most of the projects proposed in the capex application have not been fully subjected to the framework. EnergyAustralia's new framework is intended to give more attention to the early stages of planning and ensure the most appropriate option for addressing a network constraint, or other need, is chosen.

The ACCC welcomes EnergyAustralia's new framework as it should lead to more efficient investment in its network. However, as EnergyAustralia is still conducting many projects under its older procedures, changes made to past procedures have not materially affected the ACCC's assessment of the prudence of investment in this decision.

3.5 Replacement capex

3.5.1 Application

EnergyAustralia proposed $156m for its replacement capex, which comprises $94m for the ex ante capex allowance and an estimated $62m for contingent projects.

EnergyAustralia has a capital replacement policy in place to identify assets that need to be replaced. This policy is intended to control the percentage of assets that have an actual service age in excess of the standard regulatory life of its asset class.

EnergyAustralia states that the age profile of its system requires planning of replacement to be based on a combination of two major needs:

- strategic requirements—to ensure an overall sustainable age and condition profile over time
- condition based requirements—to ensure that assets which are aged or are poorly performing are identified and replaced.

To ensure that its system age and condition remain within sustainable limits and lifecycle costs are minimised EnergyAustralia's guidelines require:

- no more than 10 per cent of the total asset base (in dollar terms) should exceed the standard asset life
- no more than 10 per cent (in dollar terms) of a single category of assets should exceed the standard asset life
- condition monitoring criteria, wherever possible, for specific classes of assets.

For risk assessment, EnergyAustralia has developed a condition and risk assessment (CRA) methodology. Under the CRA a risk rating for operating items of equipment is prepared, using the matrix shown in table 3.1.

Each asset is given a risk rating for three different time envelopes. These are less than five years, between five and ten years, and between 10 and 20 years. For example, an asset may be assigned a risk rating of D2 for the time envelope less than 5 years, but be assigned a risk rating of C2 in the time envelopes between five and ten years, and 10 and 20 years.

Table 3.1 EnergyAustralia's risk assessment matrix

		Consequences				
		1	2	3	4	5
Likelihood		Insignificant	Minor	Moderate	Major	Catastrophic
A	Almost certain	A1 (H)	A2 (H)	A3 (E)	A4 (E)	A5 (E)
B	Likely	B1 (M)	B2 (H)	B3 (H)	B4 (E)	B5 (E)
C	Possible	C1 (L)	C2 (M)	C3 (H)	C4 (E)	C5 (E)
D	Unlikely	D1 (L)	D2 (L)	D3 (M)	D4 (H)	D5 (E)
E	Rare	E1 (L)	E2 (L)	E3 (M)	E4 (H)	E5 (H)

Risk rating	
E–Extreme	Immediate action required
H–High	Senior management attention required
M–Moderate	Management responsibility must be specified
L–Low	Manage by routine procedures

3.5.2 PB Associates' comments

PB Associates supported EnergyAustralia's strategy of progressing with its CRA process for determining the replacement of assets.

However, PB Associates did not consider that the complexity of cable construction and the cost of repair should be drivers behind the extent to which an asset is permitted to operate beyond its standard life.

PB Associates accepted that transmission circuits are often of strategically higher importance than distribution cables and that they are more expensive and more time consuming to repair when subject to fault. However, PB Associates consider that the time to repair and the strategic importance is the reason such circuits are planned and constructed with an amount of system redundancy. PB Associates also noted that for some transmission assets, EnergyAustralia's CRA has resulted in an expected life shorter than suggested by its standard asset life.

PB Associates recommended that assets which were given a CRA of C2 did not necessarily have to be replaced in this regulatory period due to the possibility of failure being moderate and the consequence of any failure being minor.

3.5.3 Supplementary draft decision

The ACCC's supplementary draft decision allowed $92m for replacement capex, of which $55m is for the ex ante capex allowance and $37m for contingent projects. This is shown in table 3.2.

Contingent replacement projects

EnergyAustralia proposed that the following replacement projects be classed as contingent:

- replacement of feeders 908 and 909.
- refurbishment of Ourimbah substation.

Table 3.2 Replacement capex

Capex ($m 2004–05)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's forecast						
Ex ante capex allowance	26.8	22.2	15.0	15.0	15.0	93.9
Contingent capex	0.5	4.4	25.7	22.1	9.6	62.3
Total	27.3	26.6	40.7	37.1	24.6	156.2
ACCC supplementary draft decision						
Ex ante capex allowance	17.1	12.5	5.4	7.8	12.3	55.0
Contingent capex[(a)]	0.4	1.5	16.4	12.4	6.0	36.7
Total capex allowance	17.5	14.0	21.8	20.2	18.3	91.7

(a) This amount has been provided as an indicative allowance for contingent replacement capex. The reasons for this allowance are discussed in section 3.9.4.

3.5.4 Submissions

Early replacement

EnergyAustralia disagrees with PB Associates' view about the timing of its replacement capex. EnergyAustralia considers that replacing assets ahead of time is justified on the basis that it is facing a large amount of assets reaching the end of their standard life in the next regulatory period. Further it notes that it considers that it will be able to obtain synergies and efficiencies with other capital works taking place.

The EMRF supports the supplementary draft decision in assessing that EnergyAustralia's proposed substantial increase in replacement capex was based on replacing assets before their condition warranted it.

Risk categorisation

EnergyAustralia was particularly concerned that the supplementary draft decision did not highlight that the CRA defines 'minor consequences' as:

- equipment damage of up to $1m
- third party property damage of up to $10m.

Further EnergyAustralia wrote to the ACCC to inform it of two recent failures of assets that were categorised as C2 for the period of less than five years. While these asset failures were on the distribution networks, they were presented to show the likelihood of C2 assets failing. EnergyAustralia noted that the failure of a circuit breaker created the circumstances that led to an outage of an entire zone substation and about 19,400 customers.

It requests the ACCC recognises these risks and increase the replacement expenditure from the supplementary draft decision.

Substation equipment and mains

EnergyAustralia is concerned that the reduction in proposed expenditure on substation equipment and mains is based on PB Associates' recommendation to disallow the expenditure as they had not been provided with individual reports for each item of switchgear.

EnergyAustralia did not provide individual reports because it considered that the long term and strategic view of replacement would be sufficient to justify the expenditure. EnergyAustralia questions why the ACCC would seek such specific information. It requests that the ACCC review its decision and reinstate funding for the full program.

Feeder 860

In the supplementary draft decision, the ACCC did not provide expenditure for the replacement of feeder 860. EnergyAustralia highlights that the feeder is 70 years old and the condition assessments show that it is showing signs of ageing and will need to be replaced in the near future. EnergyAustralia believes it would be more economic for it to replace the feeder rather than continue to spend resources to maintain it.

Transformer and reactors

EnergyAustralia is concerned with PB Associates' recommendation for further investigation regarding potential for refurbishment for many of the transformers and reactors when the condition reports show clear signs of ageing.

EnergyAustralia believes refurbishment is not a viable option for transmission transformers on a large scale, particularly in cases where the transformer is within 10 years of the end of its standard life. EnergyAustralia is of the view that for transformers listed in its supplementary application, refurbishment is not a viable option.

Specifically, EnergyAustralia believes refurbishment of the transformers at Kurri and Canterbury is not economic as the units are within seven to eight years of the end of their standard life. EnergyAustralia plans to replace these transformers rather than refurbish them.

Further, in the next regulatory period EnergyAustralia consider there to be more than 20 transformers that will need replacing and it believes it is impractical for this to occur. Therefore, EnergyAustralia proposes that those transformers where the condition report shows the units are closer to reaching their serviceable lives should be brought forward and be replaced in this regulatory period.

ACCC's considerations

The issues raised above all relate to the age and condition of EnergyAustralia's assets, and how they are ranked in the CRA.

The ACCC considers that asset age is not the only factor used to determine when an asset should be replaced. Feeder 860, which has not been replaced for 70 years, is an example of this.

Other factors to be considered where assets are reaching the end of their standard life include:

- economies of scope and scale
- the amount of refurbishment that has been undertaken to extend the asset's life
- the amount and type of load borne by an asset over its life
- the type of asset
- the asset's condition.

The ACCC acknowledges that based on their age profile a substantial number of EnergyAustralia's assets will reach the end of their standard lives in the next regulatory period and may require replacement.

However, in considering EnergyAustralia's replacement program the ACCC must also consider the cost to customers. Clause 6.2.2 of the code provides, amongst other things that the regulatory regime applied by the ACCC must seek to achieve certain outcomes including:

- an efficient level of investment
- efficient use of existing infrastructure.

PB Associates advice was that the CRA report supports the view that the assets rated in the C2 category are not required to be replaced in this regulatory period. The standard life of many of the assets rated C2 extends beyond the current regulatory period. Given this, the ACCC does not consider that bringing forward replacement projects can be justified on the grounds that in the next regulatory period a substantial number of assets will reach the end of their standard lives. Customers should not be required to pay for the replacement of assets in advance of when the replacement is required.

The ACCC has accepted EnergyAustralia's assertion that deliverability of its proposed replacement program during this period will not be an issue, even though the increase in replacement capex between the 1999–2004 period and the 2004–2009 period is four fold. While the ACCC has commented on the issue of deliverability, EnergyAustralia's arguments on this subject suggest that there is sufficient scope for it to increase its replacement program between the 2004–2009 period and the 2009–2014 period by a similar amount and be able to deliver it.

Further, EnergyAustralia has indicated to the ACCC that it expects to spend approximately the same amount on general replacement in 2009–2014 period as it proposes to spend in the 2004–2009 period. EnergyAustralia's ability to ramp up its replacement program between the 1999–2004 and 2004–2009 period to the degree it proposes suggests that there would sufficient scope to ramp up its replacement program to the same degree between the 2004–2009 and 2009–2014 period.

In relation to the potential for synergies and efficiencies, the ACCC considers that such synergies and efficiencies should be reflected in a lower revenue requirement. However no efficiencies have been identified nor quantified. EnergyAustralia has not previously stated it intends to achieve efficiencies in other expenditure via such strategic replacement and it has not forecast the quantity of proposed efficiencies.

The risk matrix (table 3.1) underpins PB Associates' recommendation that assets rated C2 should not be replaced in the 2004–2009 regulatory period. The ACCC notes that EnergyAustralia defined 'minor consequences' as:

- equipment damage of up to $1m
- third party property damage of up to $10m.

In forming its recommendation PB Associates considered this potential damage to equipment and third party property cost. However it must be noted that this potential cost is the expected *maximum* cost of a certain asset failure, not the expected cost of the asset should it not be replaced. That is, assuming a failure does occur the expected *maximum* cost of that failure is $10m damage to third party property and $1m damage to equipment. However the actual cost could be minimal.

EnergyAustralia states that the cost of the failure of one of its substations was an outage of about 19,400 customers. However, it noted that the failure of the C2 asset in question did not cause the outage of the entire substation. Further, in relation to the transmission assets the ACCC considers that customer outages should be minimised by transmission network planning standards, which allow for single contingency outages such as single asset failures.

Finally, while EnergyAustralia has demonstrated that C2 assets can fail, it has not demonstrated the significance of the failure rate or cost. It has collected failure rate and cost information for the past 9 months but considered it would not be appropriate to use to this data to forecast failure rates or costs for this regulatory period and therefore did not provide it to the ACCC. EnergyAustralia considers that more information should be collected before it could be used for this purpose. The ACCC is supportive of this approach to assist the justification of future replacement capex.

EnergyAustralia provided two examples of failure from all C2 assets in its entire network. In providing these examples EnergyAustralia did not provide an estimate of the costs of:

- damage to equipment
- third party property damage.

EnergyAustralia's inability to demonstrate the significance of these costs supports the view that the cost of failure of C2 assets is likely to be minor. Had EnergyAustralia suffered significant costs as a result of these types of assets failing in the past, it should have been able to quantify these costs. Rather, it stated that it considered the entire replacement program was justified by the information it had provided previously.

The ACCC accepts there will be costs to EnergyAustralia and its customers if assets rated as C2 fail. However, the risk of failure is only rated 'possible'. In reality, most assets rated as C2 will not fail and the potential cost of the failure of such assets is likely to be relatively low. EnergyAustralia's proposal to minimise these potential costs is to replace all C2 assets. This will impose a definite and substantial cost on EnergyAustralia and its customers for the replacement of assets that are not at the end of their standard life. The ACCC does not believe that the replacement costs will be outweighed by the potential cost of the failure of assets of this type.

In the supplementary draft decision the ACCC considered the replacement of C2 assets was not justified. The ACCC still considers that replacing the C2 assets in the 2004–2009 regulatory period is not justified.

For the same reasons, the ACCC has reduced the proposed expenditure on substation equipment and mains on the basis that a number of assets proposed for replacement have a CRA of C2, (see table 3.1). EnergyAustralia claimed that the basis of this reduction was its refusal to provide individual reports for each item of switchgear. This is incorrect. Further by EnergyAustralia's own estimates the assets remaining life is 10 to 20 years.

Similarly with the reduction in transmission and mains expenditure, PB Associates considered that, while condition reports showed signs of ageing, the replacement could be deferred and the current assets could be maintained with some refurbishment. The need to undertake refurbishment (which is regularly done) does not justify the replacement of assets that are not at the end of their standard life.

The ACCC considers the reasoning behind EnergyAustralia's request for increased expenditure for its replacement program is not supported by PB Associates interpretation of the CRA. The ACCC believes that bringing forward the replacement of assets where the condition report shows that they do not require replacement until at least the next regulatory period is not reason enough to relace the asset this regulatory period. Where assets are seven to eight years out from the end of their standard lives in line with PB Associates' recommendation the ACCC considers it appropriate that refurbishment should be at least considered before replacing the asset.

Historic replacement capex

EnergyAustralia questions the relevance of the ACCC using its historic replacement capex as an indicator of how large its forward capex program should be. EnergyAustralia consider that its assets are not all reaching the end of their standard lives at the same time and it believes that there is a higher need for replacement in the next 15 years.

ACCC's considerations

The ACCC did not use EnergyAustralia's historic replacement capex as an indicator of how large the forward capex program should be.

Rather, the ACCC highlighted the increase in allowed expenditure in replacement for this regulatory period, when compared to the actual capex in the previous regulatory period. The ACCC considers it important to identify that even with the reductions made to the proposed replacement capex program; it still represents a substantial increase, compared to EnergyAustralia's replacement capex in the last regulatory period.

Ourimbah

EnergyAustralia supports the ACCC's supplementary draft decision to include the Ourimbah substation in the ex ante cap. However it does not endorse the reduction in the allowance sought for the project or the proposed deferral which was recommended by the ACCC in its supplementary draft decision. Ourimbah contains some of EnergyAustralia's oldest equipment and EnergyAustralia states that some of the equipment has already failed.

EnergyAustralia considers that the costs to the network and the community of not replacing Ourimbah this regulatory period could be significant, especially considering the impact on customers' bills of including the Ourimbah substation is minute.

EnergyAustralia also pointed the ACCC to a report completed by SKM which indicated there are many elements within the substation that have lives limited by condition to five years or less.

ACCC's considerations

In the supplementary draft decision the ACCC stated the replacement of the Ourimbah substation did not meet the criteria of a contingent project.

The ACCC reached this decision because, while under EnergyAustralia's proposal the Ourimbah substation replacement meets the 10 per cent criteria for contingent projects, PB Associates advised that the refurbishment of the Ourimbah substation was not justified and was planned about two years ahead of when it would be required. This would defer the project to the fourth or fifth year of this regulatory period. If this project were deferred to the final two years of the 2004–2009 regulatory period the proposed capex for the period would decrease. The remaining expenditure would be outlayed in the beginning of the next regulatory period.

At the time the ACCC considered delaying the project to be appropriate because the replacement of an entire substation was significant enough to warrant a full condition assessment, which had not been undertaken. Further, PB Associates considered that the CRA indicated that many assets within the substation would not need replacement in the next five years.

The ACCC adopted the lower capex of $10m recommended by PB Associates and included it in the ex ante capex allowance, rather than accepting EnergyAustralia's proposal of a contingency project worth $26m.

Since the release of the supplementary draft decision, EnergyAustralia has provided further information regarding the need for the Ourimbah replacement earlier in this regulatory period.

EnergyAustralia stated that although some of the assets' condition suggested they could be used for more than 5 years, loading issues would warrant their replacement. Further EnergyAustralia stated that the consequences of this substation failing is a loss of supply to about 49,000 customers. In addition EnergyAustralia has noted that an explosive failure has already occurred within this substation.

In considering this replacement project, the ACCC considers that the CRA rating of C2 to some assets may be understating their risk given the potential consequences of their failure.

In making its decision about the prudence of the proposed expenditure the ACCC examined the capex proposed by EnergyAustralia. The proposed capex included an interest during construction cost of 7.5 per cent. The ACCC has modelled the cash flows on a cash spend basis rather than on a commissioning date approach. Under this approach including capital for interest during construction would amount to double counting.

EnergyAustralia stated that this interest during construction was inadvertently included in the forecast for Ourimbah, but it was not included in any other project.

Given the importance of the Ourimbah substation to the supply of the central coast, the ACCC believes EnergyAustralia has demonstrated that the expenditure for the Ourimbah substation replacement is warranted and the project should go ahead this regulatory period. Therefore, the ACCC has included the full $26m proposed by EnergyAustralia, less $2m for interest during construction, in the ex ante allowance for the replacement of the Ourimbah substation.

3.5.5 Impact on opex

The EUAA, EMRF and EnergyAustralia each address the impact on opex that the capex allowance in the supplementary draft decision would have.

EnergyAustralia requests an increase of approximately $20m in opex to cover the costs of maintaining assets that were not approved for replacement. EnergyAustralia considers the opex/capex trade off is heavily influenced by the type of equipment that is maintained or replaced. It believes that in the case of the substation mains and equipment which suffered the most cuts, the costs of maintaining these assets is high.

The EUAA and EMRF are concerned the increase in capex from the draft decision has not been followed up with a corresponding reduction in the opex allowance. The EUAA also is concerned the terms of reference for PB Associates did not include a requirement to determine how the increase in replacement capex would impact on the required allowance for opex. The EUAA considers that an increase in replacement capex without a corresponding reduction in opex is exploiting customers.

The EUAA would also like to see the ACCC benchmark the level of replacement capex and opex so that a matrix can be applied to all TNSPs.

The EMRF believe there is a close relationship between opex and capex. It considers that the greater the capex, the less opex is required to manage the introduction of capex. It believes that the ACCC should make compensating adjustments to the opex awarded to the transmission businesses as a result of the increase in capex allowed. It considers this is a poor outcome for consumers.

ACCC's considerations

The ACCC has not set EnergyAustralia's opex allowance based on the level of replacement capex that it has determined to be appropriate. Opex is set independently by considering other factors that influence opex. This consideration is set out in chapter 5. While the ACCC is aware that a relationship between opex and replacement capex may exist, it does not measure this relationship in order to set an opex allowance. In fact it would be very difficult to quantify.

This difficulty is highlighted by EnergyAustralia's application. In its original application EnergyAustralia proposed that $80m replacement capex would be required. In the revised capex application EnergyAustralia proposed $156m of replacement capex would be required. Yet EnergyAustralia stated that no reduction to opex was warranted because of the type of assets proposed for replacement.

However, EnergyAustralia also argues that, if the ACCC does not approve the full replacement capex allowance sought by EnergyAustralia, an increase in opex is justified. While there may be a relationship between opex and replacement capex, it is inconsistent and difficult to quantify. This makes replacement capex an unreliable tool in determining an appropriate level of opex.

Therefore the ACCC considers that increases or decreases to the opex allowance due to the changes made to replacement capex are not warranted.

3.5.6 Impact on prices

EnergyAustralia calculated the average impact on the bill of end use customers if the ACCC approved the full proposed replacement program. EnergyAustralia consider customers would be willing to pay the small increase to ensure reliable supply to the network.

ACCC's considerations

The ACCC is aware of the impact on prices that EnergyAustralia's proposed capex program would have. The ACCC identifies that while the price impact may be small for individual customers it still should not be paid when it is not necessary. Further, the ACCC does not have a role in determining specific prices, this is a matter for the code.

3.5.7 Decision

Table 3.3 shows the ACCC's decision in relation to an efficient amount of replacement capex.

The ACCC's forecast of efficient replacement capex is not a list of approved projects. Rather, it is a capex allowance available to EnergyAustralia for it to allocate to projects that it considers are necessary in maintaining the reliability of its network. It is EnergyAustralia's responsibility to allocate the capex allowance efficiently to ensure any risk of failure to its network is minimised.

Therefore the ACCC's decision is to allow $106m for replacement capex, of which $69m is for the ex ante capex allowance and $37m for contingent projects.

Table 3.3 Replacement capex

Capex ($m 2004–05)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's forecast						
Ex ante capex allowance	17.3	21.0	18.7	21.2	15.6	93.8
Contingent capex	0.5	4.4	25.8	22.1	9.6	62.4
Total	17.8	25.4	44.5	43.3	25.2	156.3
ACCC's decision						
Ex ante capex allowance	14.5	14.5	14.8	16.2	9.1	69.2
Contingent capex[a]	0.4	1.50	16.4	12.4	6.0	36.7
Total capex allowance	14.9	16.0	31.2	28.6	15.1	105.9

(a) This amount has been provided as an indicative allowance for contingent replacement capex. The reasons for this allowance are discussed in section 3.9.4.

3.6 Augmentation capex

3.6.1 Application

EnergyAustralia proposed $95m for its augmentation capex, which comprised of $48m for the ex ante capex allowance and an estimated $47m for contingent projects.

EnergyAustralia propose the following augmentation capex projects be excluded from the ex ante capex allowance.

- major inner metropolitan 132kV development
- six customer connections
- Lower Hunter 132kV development
- variation claim for Haymarket tunnel.

3.6.2 PB Associates' report

In reviewing EnergyAustralia's proposed augmentation capex, PB Associates accepted the majority of the expenditure, but made recommendations on the following:

- Deferring Newcastle Western Corridor for one year, thus reducing expenditure in this regulatory period
- Deferring a third transformer at West Gosford zone substation by one year, thus reducing the expenditure in this regulatory period
- Increasing the expenditure to install a third transformer and upgrade the 132kV protection and fibre optic communications at Macquarie Park zone substation. The increase was due to EnergyAustralia unintentionally omitting the expenditure for the communications and protection capex.

3.6.3 Supplementary draft decision

The ACCC's supplementary draft decision allowed an augmentation allowance of $58.48m, all of which was in the ex ante capex allowance.

Table 3.4 Augmentation capex

Capex ($m 2004–05)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's forecast						
Ex ante capex allowance	19.6	3.9	5.6	7.2	11.7	48.0
Contingent capex	0.2	4.5	17.0	15.7	9.9	47.3
Total	19.8	8.4	22.6	22.9	21.6	95.3
ACCC supplementary draft decision						
Ex ante capex allowance	19.8	7.1	10.4	9.1	12.0	58.5
Contingent capex(a)	0.0	1.2	11.8	13.0	9.7	35.7
Capex allowance	19.8	7.1	10.4	9.1	12.0	58.5

(a) No amount has been provided as an indicative allowance for contingent augmentation capex. The reasons for this are discussed in section 3.9.4.

Major Inner Metropolitan 132 kV development

The Major Inner Metropolitan 132 kV development exceeds 10 per cent of the total capex and has associated uncertainties outside of the control of EnergyAustralia. Therefore the ACCC considered it to be a contingent project.

Customer connections

The ACCC considered it appropriate that the party wishing to connect should pay the costs of assets dedicated to its connection. Hence EnergyAustralia's capex should only include the costs associated with augmenting the shared transmission network.

The ACCC considers proposed customer connections should only be treated as contingent projects if all of the following criteria are met:

- the connection to EnergyAustralia's transmission network is going ahead
- a regulatory test assessment requires shared network augmentation
- the shared network augmentation required in the regulatory period is material
- the shared network augmentation is not already allowed in other augmentation projects.

Lower Hunter 132kV network development

EnergyAustralia's proposed capex for the Lower Hunter 132kV network development does not exceed 10 per cent of the ex ante capex allowance, which indicates it should be included in the allowance.

The ACCC acknowledged that uncertainties outside the control of EnergyAustralia existed, in particular uncertainty concerning the outcome of TransGrid's planning in the Lower Hunter area. However, at the time of the supplementary draft decision the ACCC understood that TransGrid had decided on a course of action, which removed a lot of this uncertainty. Therefore the only remaining issue was the cost estimates, and their accuracy.

The ACCC considered that in light of this, the Lower Hunter 132kV network development should be included in the ex ante capex allowance. The ACCC included the $12m in the ex ante capex allowance. EnergyAustralia was invited to provide more up-to-date forecasts for inclusion in the final revenue cap decision.

Claim for variation for the Haymarket tunnel

EnergyAustralia had not provided any information about this claim at the time of publishing the supplementary draft decision.

Without details of this claim or further explanation from EnergyAustralia about the reasons for withholding these details the ACCC was not able to account for these costs in this revenue cap.

3.6.4 ACCC's considerations

Lower Hunter 132kV network development

EnergyAustralia accepts the move of the Lower Hunter project to the main ex ante allowance but seeks to update the estimates included in the cap. In light of the information gained regarding TransGrid's project decision, EnergyAustralia seek to have the cost estimates for its project option 2 ($16m) included in the ex ante allowance.

The ACCC is satisfied with EnergyAustralia's updated estimates and therefore will include $16m in the ex ante allowance.

Major inner metropolitan 132 kV development; customer connections; Haymarket tunnel

In moving from the supplementary draft decision to the final decision, the only change to the ACCC's considerations relate to the lower Hunter project as outlined above. For the remaining projects, the ACCC's findings and reasons in the supplementary draft decision remain unchanged.

3.6.5 Decision

Table 3.5 represents the ACCC's decision in relation to an efficient amount of augmentation capex.

The ACCC's forecast of efficient augmentation capex is not a list of approved projects. Rather, it is an allowance EnergyAustralia can allocate to projects of its choice and ultimately it is one factor used to determine EnergyAustralia's revenue cap. It is EnergyAustralia's responsibility to ensure that it allocates its expenditure to projects that are required to minimise any risk of failure to its network.

Table 3.5 Augmentation capex

Capex ($m 2004–05)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's forecast						
Ex ante capex allowance	26.8	3.8	5.6	7.4	11.6	55.2
Contingent capex	0.2	4.5	17.0	15.7	9.9	47.3
Total	27.0	8.3	22.6	23.0	21.5	102.4
ACCC's decision						
Ex ante capex allowance	27.0	8.2	12.2	10.1	12.1	69.6
Contingent capex[a]	0.0	1.2	11.8	13.0	9.7	35.6
Capex allowance	27.0	9.3	24.0	23.1	21.8	105.3

(a) No amount has been provided as an indicative allowance for contingent augmentation capex. The reasons for this are discussed in section 3.9.4.

3.7 Compliance capex

3.7.1 Application

EnergyAustralia's proposed compliance capex is $4.12m. The program comprises projects required to upgrade existing infrastructure to meet code and other legal requirements or to achieve its duty of care requirements.

3.7.2 PB Associates' report

PB Associates considers that EnergyAustralia's proposed compliance capex is justified and the likelihood of the projects proceeding is high. Therefore, it did not recommend any alterations to the compliance capex program.

3.7.3 ACCC's supplementary draft decision

The ACCC's supplementary draft decision accepted EnergyAustralia's proposed program. The ACCC considered that this capex had been justified in order for EnergyAustralia to be able to meet its external and regulatory requirements. Although the review was undertaken at a relatively high level, the magnitude of expenditure did not warrant any more detail than EnergyAustralia provided.

Table 3.6 represents the ACCC's supplementary draft decision in relation to an efficient amount of compliance capex.

Table 3.6 Compliance program

Capex ($m 2004–05)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's forecast						
Ex ante capex allowance	0.8	0.8	0.8	0.8	0.8	4.1
Excluded capex	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.8	0.8	0.8	0.8	0.8	4.1
ACCC supplementary draft decision						
Ex ante capex allowance	0.8	0.8	0.8	0.8	0.8	4.1
Contingent capex	0.0	0.0	0.0	0.0	0.0	0.0
Total capex allowance	0.8	0.8	0.8	0.8	0.8	4.1

3.7.4 Submissions

No submissions were received in regards to the supplementary draft decision on EnergyAustralia's compliance program.

3.7.5 ACCC's considerations

In reaching its decision on EnergyAustralia's proposed compliance projects program, the ACCC has taken into consideration EnergyAustralia's supplementary capex application and PB Associates' report.

The ACCC's decision does not alter from its draft decision. Therefore, it accepts the program proposed by EnergyAustralia.

3.7.6 Decision

Table 3.7 represents the ACCC's decision in relation to an efficient amount of compliance capex. The ACCC's forecast of efficient compliance capex is not a list of approved projects. Rather, it is an amount of money EnergyAustralia can allocate to projects that are necessary to minimise any risk of failure to its network and, ultimately, it is one factor used to determine EnergyAustralia's revenue cap.

Table 3.7 Compliance program capex

Capex ($m 2004–05)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's forecast						
Ex ante capex allowance	0.9	1.2	1.3	0.6	0.1	4.1
Contingent capex	0.0	0.0	0.0	0.0	0.0	0.0
Total	0.9	1.2	1.3	0.6	0.1	4.1
ACCC supplementary draft decision						
Ex ante capex allowance	0.9	1.2	1.3	0.6	0.1	4.1
Contingent capex	0.0	0.0	0.0	0.0	0.0	0.0
Capex allowance	0.9	1.2	1.3	0.6	0.1	4.1

3.8 Non-system capex

3.8.1 Application

In its supplementary application, EnergyAustralia proposed a non-system capex program of $28m.

EnergyAustralia's non-system capex is broken down into asset classes. It is submitted for the whole of business and, therefore, includes distribution expenditures. EnergyAustralia allocates expenditure to its transmission network by calculating the total expenditure as a percentage of transmission assets against total network assets. That is, 12.4 per cent of its network assets are transmission assets. Hence, 12.4 per cent of its non-system capex is allocated to transmission.

3.8.2 PB Associates' report

PB Associates considers that EnergyAustralia's proposed non-system capex is justified; however it did raise concerns about the allocation methodology for allocating expenses between the transmission and distribution businesses, particularly when considering the IT expenditure.

PB Associates recommended that this allocation methodology be further explored before the next regulatory reset to determine whether there is a more effective way to allocate the costs between the businesses.

For the purpose of this revenue cap reset, however, PB Associates' did not recommend any alterations to the compliance capex program.

3.8.3 Supplementary draft decision

The ACCC considered that EnergyAustralia's non-system capex allocation method raises a concern because it may over or under estimate the efficient level of transmission non-system capex. PB Associates also highlighted its concern regarding the use of the allocation methodology, particularly when considering IT expenditure.

In the supplementary draft decision the ACCC recognised that this allocation method was used for EnergyAustralia's distribution review and, therefore, adopting a different allocation method for the transmission review could allow EnergyAustralia to over or under recover revenue. It could also provide perverse incentives for EnergyAustralia to reallocate expenditure from distribution to transmission or vice versa. Therefore the ACCC adopted EnergyAustralia's proposed allocation method for this regulatory period.

Table 3.8 represents the ACCC's supplementary draft decision in relation to an efficient amount of non-system capex.

Table 3.8 Non-system capex

Capex ($m 2004–05)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's forecast						
Ex ante capex allowance	5.5	5.5	5.5	5.5	5.5	27.6
Contingent capex	0.0	0.0	0.0	0.0	0.0	0.0
Total	5.5	5.5	5.5	5.5	5.5	27.6
ACCC supplementary draft decision						
Ex ante capex allowance	5.5	5.5	5.5	5.5	5.5	27.6
Contingent capex	0.0	0.0	0.0	0.0	0.0	0.0
Total capex allowance	5.5	5.5	5.5	5.5	5.5	27.6

3.8.4 Submissions

No submissions were received in relation to the supplementary draft decision on EnergyAustralia's non-system capex.

3.8.5 ACCC's considerations

In reaching its decision on EnergyAustralia's proposed non-system capex program, the ACCC has taken into consideration EnergyAustralia's supplementary capex application and PB Associates' report.

The ACCC's decision does not alter from its draft decision. Therefore, it accepts the program proposed by EnergyAustralia.

3.8.6 Decision

Table 3.9 represents the ACCC's decision in relation to an efficient amount of non-system capex. The ACCC's forecast of efficient non-system capex is not a list of approved projects. Rather, it is an amount of money EnergyAustralia can allocate to projects that are necessary to minimise any risk of failure to its network and, ultimately, it is one factor used to determine EnergyAustralia's revenue cap.

Table 3.9 Non-system capex

Capex ($m 2004–05)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's forecast						
Ex ante capex allowance	5.5	5.5	5.5	5.5	5.5	27.6
Contingent capex	0.0	0.0	0.0	0.0	0.0	0.0
Total	5.5	5.5	5.5	5.5	5.5	27.6
ACCC supplementary draft decision						
Ex ante capex allowance	5.5	5.5	5.5	5.5	5.5	27.6
Contingent capex	0.0	0.0	0.0	0.0	0.0	0.0
Total capex allowance	5.5	5.5	5.5	5.5	5.5	27.6

3.9 Other issues

3.9.1 Indexation of the ex ante capex allowance

EnergyAustralia proposes that the ex ante capex allowance should be dynamically adjusted according to growth in the following ABS indices:

- average weekly earnings (seasonally adjusted) persons, all employees total earnings catalogue no. 6302
- producer price index catalogue no. 6427, table 19 materials used in other than house building (Sydney)
- producer price index catalogue no. 6427, table 11 articles produced by manufacturing industries—electrical equipment and appliance manufacturing (ANZSIC code 2852 and 2859).

EnergyAustralia states its capex costs comprise labour, equipment and construction costs and that forecast capex must be adjusted for changes to these costs.

EnergyAustralia has also noted the impact of the exchange rate on its input costs and stated it would work with the ACCC to develop an appropriate adjustment for the final revenue cap.

Supplementary draft decision

In its supplementary draft decision, the ACCC considered the ex ante capex allowance should, if possible, be allowed to adjust by appropriate indices. The ACCC accepted that there is a general link between the proposed indices and EnergyAustralia's input costs, however it is concerned that they are not specific links.

The average weekly earnings index is based on the economy wide change in wage costs. Whereas wage costs of EnergyAustralia will be heavily influenced by the supply and demand of specific skills, rather than supply and demand of labour across the economy.

It is a similar case for the producer price indices proposed. The price of building materials except for material for building houses index is not based on the specific cost of building materials that are inputs to transmission building. The producer price index for articles produced by manufacturing industries is based on a variety of manufacturing industries that are irrelevant to transmission building.

Therefore the ACCC considered the proposed indexes to be economy wide indicators, rather than specific to transmission input costs.

The SRP[33] states that setting the ex ante capex allowance is intended to establish certainty and incentives for efficiency. To achieve this, the ex ante capex allowance is required to be linked to the efficient costs for the period. The ACCC considered that the general indices proposed do not achieve this.

It was noted EnergyAustralia included forecast increases in input costs in its capex forecasts, which were reviewed and, for the majority, accepted as reasonable.

The ACCC considered that EnergyAustralia had not demonstrated that there is a problem with the ACCC's current use of the CPI. It also believed that EnergyAustralia had not been able to demonstrate that its proposed ABS indices are better than the ACCC's use of the CPI.

CPI is a commonly used and widely accepted measure of inflation that has been employed by the ACCC in its previous revenue cap determinations. The continued use of CPI by the ACCC will help achieve reasonable certainty and consistency over time in the outcomes of the ACCC's regulatory processes. This objective is less likely to be achieved if the ACCC begins tailoring indices for each regulated entity.

Submissions

In its submission, EnergyAustralia believes it is appropriate to link costs incurred by transmission businesses to indices other than CPI. EnergyAustralia does not believe

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33 SRP—background paper, op.cit., p. 56.

that the CPI is an accurate measure of the cost pressures facing transmission companies.

EnergyAustralia provided data relating to the annual percentage change for basic metals and fabricated metal products. These materials represent 30 per cent of EnergyAustralia's input costs for electrical equipment. EnergyAustralia states that it has anecdotal evidence from steel manufacturers which shows that the increased prices are likely to continue for some time, driving price increases above CPI.

EnergyAustralia considers this movement in prices highlights the need for the regulator to build in flexibility to take account of the external cost factors.

EnergyAustralia also considers the current skill shortage in its industry is likely to continue, which will result in real labour cost increases that are higher than CPI.

EnergyAustralia believes that indexing material and labour costs to published indexes would improve the transparency of the capital cost cycle and would help to explain the variations in actual project costs compared to estimates made by transmission planners. Furthermore, linking costs to an appropriate index is also likely to mitigate the potentially negative cash flow risks that are borne by the business when transmission cost inputs increase at a greater rate than CPI.

ACCC's considerations

The SRP provides flexibility to include a dynamically adjusted allowance to apply in instances where the cost driver is clearly exogenous, for example where there are changes in reliability requirements imposed on TNSPs, or where there is growth in peak demand. In these instances the TNSP is unable to use hedging or other instruments to mitigate the risks it faces.

However, the ACCC believes that dynamically adjusting the capex allowance for index costs such as those requested by EnergyAustralia is inconsistent with the ex ante capex regime where the TNSP is provided with incentives to manage their input costs. If the ACCC was to approve the indices proposed by EnergyAustralia, EnergyAustralia would have limited incentive to seek lower input costs through, for example, using alternative suppliers or entering into contracts to manage these exogenous costs, which is considered to be good management practice.

Furthermore, within the ex ante allowance there are likely to be costs that are higher than forecast and costs that are lower than forecast. It is the role of the TNSP to balance those movements through more efficient and prudent practices.

The ACCC also reiterates that there is no evidence to suggest that there is a strong correlation between the indices proposed by EnergyAustralia and the cost items to be adjusted. Furthermore, EnergyAustralia has not demonstrated that the costs it claims to be exogenous cannot be controlled through other instruments such as those outlined above.

For the reasons discussed above, the ACCC's decision is to set an ex ante capex allowance that does not dynamically adjust.

3.9.2 Deliverability

In its report to the ACCC, PB Associates commented that deliverability of EnergyAustralia's proposed capex may become an issue over the regulatory period. EnergyAustralia in its submission expressed concerns that these comments were unwarranted.

Supplementary draft decision

In its supplementary draft decision, the ACCC understood these comments to be in reference to events that are external to EnergyAustralia's control. An example of such an external event was given by EnergyAustralia on page 78 of its revised capex application, albeit in another context, it stated that:

> Due to the fact that a large number of Transmission and Distribution businesses have significantly increased their capital expenditure program, and despite having a range of period contracts in place for particular types of equipment, EnergyAustralia is currently experiencing difficulties in sourcing particular types of equipment.

The ACCC noted that no matter how well managed a network is, there will be external pressures that have the potential to delay capex. Other examples of similar external pressures include:

- increasing opposition to infrastructure development in community consultation
- changing development approval processes
- changing environmental and safety regulations.

While these external pressures are recognised and planned for by EnergyAustralia, it is difficult to quantify their impact on forecast capex. This unquantifiable impact of increasing demand for required resources to deliver increasing network capex can have two impacts on capex over the regulatory period.

First, an increased demand for resources may result in EnergyAustralia paying higher prices for these resources. EnergyAustralia has factored these potential input cost increases into its capex forecasts.

Second, if the required resources are stretched beyond their capacity, the capex over the regulatory period will be reduced because of forced delays. EnergyAustralia does not appear to have factored this into its forecast capex.

After its review of EnergyAustralia's proposed capex, PB Associates recommended a total capex program smaller than the proposal based on factors it was able to quantify. In doing so it accepted that there would be higher input costs but it also concluded that some capex proposed would be delayed. This recommendation was consistent with its comments about the deliverability.

The supplementary draft decision allowed a 28 per cent increase upon actual capex from the last regulatory period. In calculating this increase, the ACCC considered that the external pressures to deliver capital would not require a reduction in the allowed capex. However had the ACCC allowed an increase of the order proposed by EnergyAustralia the issue of deliverability would have required further attention.

Submissions

EnergyAustralia notes that deliverability is an issue for the business to manage internally. It states that it has taken steps to ensure that it can deliver the capital program the network requires. EnergyAustralia also believes that the ACCC has begun a dangerous trend of second guessing the deliverability of programs without having expertise in the area. EnergyAustralia considers the ACCC's comments are unwarranted and unacceptable, and it requests that they be removed from the final decision.

The EMRF believes that the size of the capex program proposed is an important issue in light of the challenges TNSPs and DNSPs are continually referring to regarding access to resources to complete the large amount of capex projects being permitted by regulators in all jurisdictions.

The EMRF consider that the over commitment of capex across the NEM will have the following three major implications:

- the cost of each project will increase above reasonable levels due to competition for scarce resources
- shortage of resources will delay project completions reducing the net cash benefits of the capex
- consumers will be paying for the return on capex included in the revenue, but which does not deliver the benefits to the consumers they are paying for.

The EMRF considers that the ACCC has a responsibility and obligation to ensure that any capex included in the revenue has a high likelihood of being completed on time and to the amount included in the cost benefit analysis.

ACCC's considerations

The ACCC considers that its comments on deliverability are warranted. There are, as with all businesses, external pressures that can affect the running of and investment in the network.

EnergyAustralia have stated that they have planned for these external factors and can deliver capex outcomes. Therefore the ACCC takes a conservative position and has accepted EnergyAustralia's statements about deliverability. Further, as was the case in the supplementary draft decision, the ACCC considers that there is no case to reduce capex because of deliverability concerns.

The ACCC will closely monitor capex outcomes and take them into account in the next revenue cap.

3.9.3 Assessing contingent capex

Supplementary draft decision

Appendix C of the supplementary draft decision outlined a process for the assessment of contingent projects. In designing this process, the ACCC attempted to align the regime with EnergyAustralia's governance procedures, which resulted in an approximate time frame of four to six months.

Submissions

In its submission EnergyAustralia raises concerns that the ACCC's framework and timeframe could create potential delays. EnergyAustralia suggested a timeframe of three to four months, which would be managed in parallel to the normal consultation requirements of the code.

EnergyAustralia acknowledges the effort of the ACCC to understand its governance procedures, but believes that further streamlining of the proposed timetable for contingent project assessment can be achieved if the process is synergised with the regulatory test.

ACCC's considerations

When considering the appropriate framework and timeframe for the contingent projects, the ACCC took into consideration EnergyAustralia's capital governance framework. The ACCC attempted to align its framework with that of EnergyAustralia's. This was difficult as EnergyAustralia did not provide details on the indicative timeframe under its capital governance procedures. Therefore, the ACCC was left to approximate what time was required.

It should be noted that the timing of its decision making is a matter for the ACCC. As stated in the supplementary draft decision, and again in this decision, the timeframe put together is indicative only. The process and times suggested are likely to vary according to project needs and the timing of EnergyAustralia's decision making processes.

The timeframes may well be shorter or longer than those indicated and should not be considered fixed. Some contingent projects may be assessed in as little as two months. An example might be where interested parties are in broad support of the proposed capex. However the ACCC does not wish to rule out a longer assessment process where the issues are more complicated and by their nature require longer times.

The ACCC expects that where it requires longer periods of time to assess the project, EnergyAustralia will also require more time to undertake its own economic and other assessments. It does not intend to unduly defer prudent capex.

Therefore the ACCC considers that allowing from two up to six months as an indicative timeframe is appropriate.

The process for the assessment of contingent projects is set out in appendix B to this decision.

3.9.4 Indicative contingent capex

Supplementary draft decision

After considering the total capex the ACCC must set a MAR for EnergyAustralia for the regulatory period. As mentioned in the SRP[34] the power to re-open a revenue cap during the regulatory period is limited. Therefore the ACCC will not be able to change EnergyAustralia's revenue cap immediately after undertaking a review of the contingent capex projects.

As with the supplementary draft decision, this decision includes an indicative revenue allowance associated with the contingent projects. This would then be adjusted, subject to a code change being proposed, in the revenue cap decision for the next regulatory period. The adjustment will be based on the ACCC's findings from reviewing each of the contingent projects.

In addition to the ex ante capex allowance ($145m) shown in table 8, the ACCC has included $37m as an indicative capex allowance for the contingent projects.

The indicative allowance was estimated as follows:

- No indicative allowance was made for the Major Inner Metropolitan 132kV network development. This was because the ACCC is uncertain that the project will be required this regulatory period. TransGrid has informed the ACCC that it is uncertain that its 330/132kV substation will be constructed before the next regulatory period.

- The ACCC considers $37m is indicative of the costs associated with the replacement of feeders 908/9. The ACCC considers this replacement project has an extremely high probability of proceeding this regulatory period, which is driven by the risks associated with not replacing the feeders.

- No indicative allowance has been made for the customer connections. The ACCC considers that such connections have a high degree of uncertainty of proceeding, scope and cost.

Submissions

The EUAA urges the ACCC to consider the sharing of benefits should the contingent projects fail to proceed when the ACCC included all, or part of, an allowance in the MAR. The EUAA believes that because customers would have already begun paying for these projects in the current regulatory period, savings achieved as a result of not proceeding with these projects should be shared.

The EUAA believes the ACCC should consider allowing the sharing of any gains from capex underspends in the following regulatory period. To ensure symmetrical treatment, customers could partially compensate the TNSPs for prudent overspending on projects that were not envisaged during the regulatory review. This may reduce the incentive to the TNSPs to overstate expected capex spend, while still providing an incentive to operate efficiently. The EUAA suggests that this could take the form of

[34] SRP—background paper, op. cit., p. 143.

an imputed credit in the revenue over the next regulatory period, thereby reducing the TNSP's allowed revenue and consequently TUoS charges payable.

ACCC's considerations

The ACCC considers that the indicative allowance provided to EnergyAustralia for feeders 908 and 909 is a one off occurrence.

The ACCC is certain that this project will proceed and has already obtained information from EnergyAustralia regarding the urgent need for the project as well as some cost estimates for the project. The indicative allowance provided to EnergyAustralia is the minimum amount that will be spent on this project. The only uncertainty of the project is exactly how much the project costs will increase by.

The ACCC does not consider that there is a need to provide customers with any compensation because the indicative allowance provided to EnergyAustralia is a minimum cost of a project that is certain to go ahead.

If contingent projects are triggered the ACCC will undertake an ex ante assessment of those projects. In concluding this assessment the ACCC will state how it intends to reconcile any indicative allowance provided in this revenue cap with the amount approved in the assessment.

The ex ante review will set a revenue cap for that particular project for a five year period commencing on the date set out in the review. However the code does not give power to the ACCC to adjust the MAR prior to the end of the regulatory period. This means that EnergyAustralia will be unable to recover any additional revenue from customers within this regulatory period.

Therefore the ACCC will include any additional revenue requirement, set by the ex ante review of the contingent project, in the 2009–2014 revenue cap on an NPV neutral basis. At the end of the five year period set for the contingent project the depreciated actual capex will be rolled into the RAB.

These details about the assessment of the contingent projects and their treatment during the next revenue cap are discussed in appendix B.

3.10 Decision

In reaching its decision the ACCC has considered EnergyAustralia's revised capex application and other information provided. It also considered PB Associates' report and the submissions received.

Table 3.10 represents the ACCC's decision in relation to an efficient amount of total capex.

Table 3.10 Total capex

Capex ($m 2004–05)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's forecast						
Ex ante capex allowance	50.5	31.5	31.1	34.8	32.8	180.7
Contingent capex	0.8	8.9	42.8	37.8	19.5	109.7
Total	51.2	40.4	73.9	72.5	52.4	290.4
ACCC's decision						
Ex ante capex allowance	48.0	29.4	33.8	32.5	26.8	170.5
Contingent capex	0.4	2.7	28.2	25.4	15.7	72.4
Capex allowance[(a)]	48.4	32.0	62.0	57.9	42.5	242.9

(a) The capex allowance includes all contingent projects. The MAR is only modelled on capex of $207m. This does not include an allowance for all contingent projects (see chapter 3.9.4).

The capex allowance that the ACCC has proposed for EnergyAustralia is not designed to fund the construction of a list of identified projects. As noted in the SRP background paper (at page 55) the capex allowance does not entail project specific approval and there is no constraint on TNSPs investing in a different suite of projects to those used in the calculation of the allowance. Similarly, the fact that a project was not considered by the ACCC in the determination of the revenue cap does not necessarily mean that it should not be funded from the capex allowance.

The capex allowance proposed by the ACCC is an amount of money available to EnergyAustralia for it to allocate to projects that it considers are necessary in maintaining the reliability of its network. It is EnergyAustralia's responsibility to allocate the capex allowance efficiently to ensure any risk of failure to its network is minimised.

4 Cost of capital

4.1 Introduction

The objective of this chapter is to estimate the efficient benchmark cost of capital or WACC that EnergyAustralia is likely to face when financing its transmission business over the regulatory period. The WACC is used to determine, in part, the return on capital.

This chapter sets out the:

- background and formula for the WACC in section 4.2
- capital asset pricing model (CAPM) used to estimate the cost of equity capital in section 4.3.

The remainder of this chapter will address the individual parameters and related matters found in the WACC and CAPM framework as follow:

- timing for setting the bond rates in section 4.4
- risk free rate in section 4.5
- inflation rate in section 4.6
- cost of debt in section 4.7
- debt raising cost in 4.8
- market risk premium (MRP) in section 4.9
- betas in section 4.10
- gearing in section 4.11
- franking credits – gamma in section 4.12
- taxation in section 4.13.

A summary of the ACCC's decisions for the parameter values is presented in section 4.14.

4.2 Background

One of the objectives of economic regulation is to provide a fair and reasonable rate of return on efficient investment (clause 6.2.2(b)(2) of the code). Clause 6.2.4(c)(4) of the code provides guidance by stating that the ACCC must have regard to the WACC of the transmission network.

The ACCC uses the risk adjusted rate of return required by investors to establish the WACC for EnergyAustralia.

Electricity transmission is a highly capital intensive industry where return on capital generally accounts for about half of the AR. Relatively small changes to the cost of capital can have a substantial impact on the AR.

Correctly assessing the WACC is important because:

- if the return on equity is too low the regulated network may be unable to earn sufficient returns for the owner. This could reduce the incentive to reinvest in the business
- if the return on equity is too high networks may have a strong incentive to overcapitalise, creating inefficient investment
- AR translates into prices for users and a higher AR means higher prices for end users.

In the SRP the ACCC outlined its view on the appropriate expression of the rate of return to be achieved and how it has been used for deriving the AR in previous regulatory decisions:[35]

> The ACCC has historically adopted a WACC which is the weighted average of the nominal post-tax return on equity and nominal pre-tax cost of debt. This is known as the nominal vanilla WACC. The vanilla WACC does not include the impact of business income tax.

Hence, the WACC formula for this decision is:

$$WACC = r_e (E/V) + r_d (D/V)$$

where:

r_e = required rate of return on equity or cost of equity

r_d = cost of debt

E = market value of equity

D = market value of debt

V = market value of equity plus debt.

The ACCC explicitly models the tax liabilities (i.e. interest expense and franking credits) of the TNSP in the cash flow model.

EnergyAustralia adopted the ACCC's post-tax approach to setting the WACC, expressed in nominal terms, in its application.

35 ACCC, Statement of principles for the regulation of transmission revenues – background paper, 8 December 2004, p. 87

4.3 The capital asset pricing model

The regulatory regime administered by the ACCC must provide for:

> a sustainable commercial revenue stream, which includes a fair and reasonable rate of return to *Transmission Network Owners* and/or *Transmission Network Service Providers* on efficient investment, given efficient operating and maintenance practices. (Clause 6.2.2(b)(2) of the code.)

Various methods can be applied to estimate return on equity (r_e) as outlined under schedule 6.1(2.2) of the code—for example, price to earning ratio, dividend growth model and arbitrage pricing theory. However, the code indicates that the CAPM remains the most widely accepted practical tool to estimate the cost of equity.

The CAPM calculates the required return given:

- the opportunity cost of investing in the market
- the market's own volatility
- the systematic risk of holding equity in the particular company.

The CAPM formula is:

$$r_e = r_f + \beta_e(r_m - r_f)$$

where: r_f = the expected risk free rate of return (usually based on government bond rates of an appropriate tenure)

$(r_m - r_f)$ = the expected market risk premium (MRP) which measures the return of the market as a whole less the risk free rate for the same period

β_e = the systematic risk (equity beta) of the individual company's equity relative to the market.

The CAPM expresses the rate of return as the nominal post-tax return on equity.

However businesses are typically funded by equity and debt. Therefore by including the cost of debt we can derive the corresponding return on capital employed. This is known as the WACC (see section 4.2). The determination of the WACC requires several parameters which are discussed in further detail below.

4.4 Timing for setting the bond rates

In determining the WACC, there are several parameters which the ACCC obtains directly from the capital market. These parameters are the:

- nominal and real Commonwealth government bond rates (used as a proxy for the risk-free rate and to derive the forecast inflation rate)
- corporate bond rate yields.

In previous revenue cap decisions, the WACC was updated for bond rates that were based on a moving average period from the date of the final decision. Despite the use of averaging to minimise short term volatility, the WACC reflects the prevailing rates from the capital market and is set on a forward looking basis. The ACCC notes that the WACC for EnergyAustralia was set on the same principle of a forward looking basis at the time of the draft decision. Therefore under normal circumstances the ACCC would update the WACC for prevailing bond rates at the time of the originally scheduled final revenue cap decision in mid 2004.

However, this decision has been delayed due to the application of the incentive framework for capex as set out in the SRP. In 2004, a NSW derogation to the code (clause 9.16.5) enabled TransGrid and EnergyAustralia to set the NSW prices for 2004–05 based on the proposed MARs that were set out in the ACCC's draft decisions dated 28 April 2004.

This derogation enabled EnergyAustralia's MAR to be assessed and finalised part way through the 2004–2009 regulatory period. This means that the ACCC's final decision sets EnergyAustralia's MAR after the start of the 2004–2009 regulatory period. This is a unique circumstance and the ACCC does not envisage that future revenue cap decisions will be made part way through a regulatory period.

Given the price for 2004–05 has already been set, the ACCC considers that it would be inappropriate to retrospectively adjust the forecast WACC for current bond rates in the market. Instead the ACCC will finalise its estimate of the WACC for EnergyAustralia with bond rates as at 28 April 2004.

It is important to recognise that normal regulatory practice is to set the WACC based on the latest information from the capital market (i.e. update the bond rates) before the start of the regulatory period as part of a final decision. The ACCC will continue to adopt the approach where the WACC is updated in the final decision for a TNSP's MAR prior to the start of the regulatory period.

4.5 Estimate of the risk-free interest rate

The risk-free rate measures the return an investor would expect from an asset with zero volatility and zero default risk. The yield on long-term Commonwealth Government Securities (bonds) is considered to be risk-free since the government can honour all interest and debt repayments. The two issues for consideration are the sampling period used to determine the risk-free rate and the term of the risk-free rate.

4.5.1 Sampling period

In the CAPM framework all information used for deriving the rate of return should be as up-to-date as possible at the time the decision comes into effect. In the case of interest rates and inflationary expectations, financial markets determine these on a continuous basis.

On this issue the SRP states:

> the ACCC considers the period (between 5 to 40 days) used to calculate the moving average of the bond rate should be left to the discretion of the TNSP when making its application. However, the TNSP will not be allowed to change the averaging period after its application is lodged.

EnergyAustralia proposes that a 10 day averaging period be used to estimate the risk-free rate.

4.5.2 Term of the risk-free interest rate

In its application, EnergyAustralia requests that a 10 year bond rate be used in its revenue cap reset. In the Network Economics Consulting Group's (NECG) report for EnergyAustralia, it contends that in adopting the length of the regulatory period as the proxy for the bond maturity, the ACCC is basing the risk-free rate on a different time variable than the MRP, for which estimates are based on the 10 year bond rate.

4.5.3 Submissions

Transend and Benchmark Economics express their support for the ACCC in adopting the 10 year bond rate for setting the risk-free rate.

EnergyAustralia supports the ACCC's decision to base the risk-free rate on the 10 year Commonwealth bond.

TransGrid states that the convention for quoting yields in Australia requires an adjustment to the bond yields for the purposes of setting a regulatory rate of return. The adjustment would convert the quoted yield to a compounded annual yield.

4.5.4 ACCC's considerations

Sampling period

The ACCC is aware of the inherent limitations associated with using either an 'on-the-day' rate or a 'historical average' in calculating the risk-free rate.

The financial theory underlying the CAPM explicitly specifies the use of ex ante returns. Using an on-the-day rate gives the best estimate of ex ante returns. Therefore theoretically on-the-day rate is more appropriate.

However, an on-the-day rate reflects short-term fluctuations which may differ from the long-term trend. Such market volatility can be minimised by averaging rates over some time before the start of the regulatory period. Several regulators have traditionally used an average rate as the risk-free rate.

The ACCC has adopted a 40 day moving average and used it in several of its earlier regulatory decisions. However, more recently, the ACCC has adopted a 10 day moving average in its Tasmanian[36], Victorian[37] and South Australian[38] revenue cap decisions.

Consistent with the SRP, the ACCC accepts EnergyAustralia's proposal to use a 10 day moving average.

Term of the risk-free interest rate

The ACCC notes that some interested parties support the view of using the risk-free interest rate which matches the length of the regulatory period. Alternatively, other interested parties believe that bond rates with terms matching the life of the assets should be used. Transmission assets have long effective lives, far exceeding the term of the most traded Australian bond with the longest maturity period (i.e. 10 years). These parties suggest that 10 year bond yields should be used in the CAPM formula.

In December 2003 the Tribunal handed down its decision on its review of the ACCC's tariff determination for transportation services on GasNet's Victorian natural gas transmission network.[39]

Although the ACCC used a 5 year rate, the Tribunal accepted GasNet's approach to calculating the risk-free rate on the basis of a 10 year government bond rate. The Tribunal cited the traditional application of the CAPM and estimation of the MRP was based on a 10 year time horizon as the basis for its decision. It therefore considered that the service provider, under the terms of the Gas code, was entitled to use a CAPM calculation based on a 10 year horizon as a legitimate basis for estimating the cost of equity.

Given the Tribunal's decision, the ACCC has adopted a 10 year government bond rate as the risk-free rate.

Maturity dates on the nominal and indexed bonds rarely correspond and require realignment using either interpolation or extrapolation, i.e. by estimating the rate at a given moment from a 'line of best fit'. The ACCC has used this approach in all of its revenue cap decisions, which is also consistent with jurisdictional regulatory decisions.

The ACCC also notes that a yield could be expressed for any defined period but typically it is convenient to quote annual rates. With bonds, the convention in Australia to obtain annual rates is to double an effective half-yearly rate. The use of effective half-yearly rates is due to interest normally being paid half-yearly. This doubling of the half-yearly rate is regarded as a nominal rate. Therefore, an adjustment is required to obtain an effective annual rate which takes into account the compounding effect over the year. The ACCC has made the relevant adjustment to the quoted bond yield.

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36 ACCC, Tasmanian Transmission Network Revenue Cap 2004–2008/09, 10 December 2003

37 ACCC, Victorian Transmission Network Revenue Caps 2003–2008, 11 December 2002.

38 ACCC, South Australian Transmission Network Revenue Cap 2003–2007/08, 11 December 2002.

39 ACCC, GasNet Access Arrangement 2004/05–2008/09, January 2002.

For this decision, the nominal 10 year bond rate and 10 day moving average for Commonwealth government bond rates as at 28 April 2004, results in a risk-free rate of 5.98 per cent (annual compounding rate).

4.6 Expected inflation rate

The expected inflation rate is not an explicit parameter in the return on equity calculation. It is a component of the risk-free rate (which has implications for the cost of both debt and equity) that can be estimated by the:

- difference between the nominal and indexed bond yields, or
- Commonwealth Treasury's inflation forecasts.

The ACCC has historically forecast the inflation rate as the difference in the nominal bond rate and inflation indexed bond rate, as determined using the Fisher equation.[40]

On this basis, for this decision the ACCC forecasts inflation of 2.49 per cent per annum.

4.7 Cost of debt

The cost of debt on commercial loans is the debt margin added to the risk-free rate as illustrated by the formula:

$$r_d = r_f + d_m$$

where:

r_d = the cost of debt

r_f = the risk-free rate of return

d_m = the debt margin.

The debt margin varies depending on the entity's gearing, credit rating and the term of the debt. Applying the cost of debt to the asset base, using the assumed gearing, will generate the interest costs for regulatory purposes.

The SRP states:[41]

> Once the relevant credit rating is established the debt margin can be determined from financial market sources. The debt margin (short term averaging period equal to the averaging of the risk free rate) should also reflect the prevailing market rates which represent

40 The 10-year and 10-day moving average for the inflation indexed bond rates as at 28 April 2004, results in a real risk-free rate of 3.41 per cent (annual compounding rate).

41 op. cit. p. 113

current market expectations for debt issues at the benchmark maturity and credit rating for the regulated entity.

EnergyAustralia proposes a credit rating of ‘BBB+’ for a utility company with benchmark gearing of 60 per cent. It believes this would be consistent with market observations. Therefore, it requests a debt margin of 135 basis points above the nominal risk-free rate.

4.7.1 Submissions

EnergyAustralia believes the ACCC’s approach to the debt margin will understate the required debt margin for an efficient benchmarked transmission business. It argues that the inclusion of government owned comparators in the list of benchmark companies biases the credit rating upwards. EnergyAustralia also contends that many electricity distributors have a rating of ‘BBB’ with gearing around 60 per cent, which implies that a rating of ‘BBB+’ for an electricity transmission provider is reasonable.

SPI PowerNet states that an appropriate benchmark credit rating for setting the debt margin would be ‘A-’ or ‘BBB+’.

Similarly, TransGrid commends that a conservative approach would be to adopt a credit rating of ‘A-’ or below.

4.7.2 ACCC’s considerations

In the SRP, the ACCC stated that it would not reference a TNSP’s actual cost of debt because the actual cost of debt may not reflect efficient financing. A WACC based on an industry wide benchmark cost of debt may deter inefficient debt financing, as the revenue cap will only contain a return on capital allowance consistent with the return requirements of efficient financing.

The cost of debt is primarily dependent on the credit rating of the debt issuer. As a general rule, debt attached with a lower credit rating has greater default risk and therefore attracts a higher risk premium. The ACCC considers that adopting a benchmark credit rating for the TNSP rather than an actual credit rating provides the firm with the incentive to minimise inefficient financing. Therefore the cost of debt should be determined through reference to a benchmark credit rating and the (market) debt margin associated with that rating.

Table 4.1 sets out the long term credit rating assigned by Standard and Poor’s for ten Australian electricity network companies.[42] It shows that EnergyAustralia has a long term rating of ‘AA’ and an actual gearing of 51.4 per cent.

[42] United Energy (now United Energy Distribution) and TXU Electricity (now SPI Electricity) are not included in the sample because they were recently acquired and undergoing restructuring which would have an impact on their long term credit ratings. However, these firms may be included in the future.

Table 4.1 Credit ratings of electricity companies

Company	Long-term rating	Actual Gearing (%)
Ergon Energy	AA+	49.3
Country Energy	AA	68.3
EnergyAustralia	AA	51.4
Integral Energy	AA	51.3
SPI PowerNet	A+	76.8
Australian Gas Light	A	40.8
Citipower Trust	A-	54.1
ETSA Utilities	A-	64.1
Powercor Australia	A-	38.1
ElectraNet	BBB+	71.9
Average	A to A+	56.6

Source: Standard and Poor's, *Australian Report Card Utilities,* October 2004.

The table also shows that the average credit rating of these entities is 'A' to 'A+' and their average gearing is approximately 57 per cent, close to the assumed benchmark of 60 per cent.

The ACCC considers that relevant samples of Australian electricity transmission and distribution companies should be used as the basis for calculating a benchmark TNSP's credit rating. There are also an insufficient number of 'transmission only' entities with publicly available credit ratings to provide a reliable industry sample.

It could be argued that the inclusion of distribution companies in the sample may provide a lower credit rating (i.e. have the effect of biasing the sample towards TNSPs) because distribution is regulated by way of a price cap rather than a revenue cap (which is more likely to provide a stronger business profile). According to Fitch Ratings, while distribution operations typically involve a low business risk, similar to transmission operations:

> … they have more exposure to volume risk than transmission companies (e.g. volumes are sensitive to mild winters or summers).[43]

Therefore a transmission company is expected to have a stronger credit rating than other players in the electricity industry.

In its sampling of the average credit rating for electricity network companies, the ACCC has included both private and government owned entities. The ACCC considers that using only stand-alone and private entities provides too small a sample

43 Fitch Ratings, Australian Electricity Sector-At That Awkward Adolescence Stage, March 2004, p 47.

to obtain an appropriate average credit rating for the electricity industry.[44] The ACCC acknowledges that the inclusion of some government owned companies in the sample is likely to create an upward bias to the credit rating. For instance, Standard and Poor's has stated that the stronger 'AA' credit rating is predominantly given to government owned utilities.[45]

Offsetting this is the inclusion of distribution companies in the sampling of credit ratings. In most Australian states, other than South Australia and Victoria, the distribution companies are bundled with retail operations. According to Standard and Poor's, retailers operate in a highly competitive market and its credit quality will always be at the riskier end of the credit spectrum.[46] Further, it is Fitch Ratings' experience that there would be only limited situations where the existence of a retailing capacity would strengthen a distributor's stand-alone credit profile.[47] Therefore the ACCC's sampling, which includes the credit ratings of bundled distribution network companies, is likely to provide a conservative credit rating for the purposes of a benchmark TNSP.

Notwithstanding this, government/parent ownership is only one factor which may affect a credit rating. According to Standard and Poor's, the method used to rate power companies incorporates an assessment of both the financial and business risk characteristics of the entity. The financial risk assessment focuses upon the ability of an entity to generate sufficient cash flows to service its debt and therefore involves consideration of the stability of an entity's revenue and gearing levels. The business risk assessment typically considers a broader range of issues which affect the key business or operating characteristics such as:[48]

- regulation
- markets
- operations
- competitiveness.

By taking into account these additional factors, the ACCC is satisfied that the Standard and Poor's credit rating does not simply reflect the ownership structure but considers more broadly the stability of the entity's operations. This conclusion can also be seen in statements made by both Standard and Poor's and Fitch Ratings who state:

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44 The ACCC understands the complexity of the number of factors considered by ratings agencies when determining a credit rating for a company. If the criteria of private and stand-alone firms is strictly considered then the sample list would reduce to include only ElectraNet. Further, it can be argued that ElectraNet should also be excluded because the Queensland government (through Powerlink) has a major ownership interest in ElectraNet.

45 Standard and Poor's, Australian and New Zealand Electric and Gas Utilities Ripe for Rationalization, May 2002, p. 1.

46 Standard and Poor's, *Energy-Australia & New Zealand*, November 2001, p. 9.

47 op. cit., p. 47.

48 op. cit., p.18.

> …the ‘A’ rated entities are generally stable network or transmission businesses.[49]
>
> …the transmission company should enjoy stronger credit ratings than other players in the electricity chain, because of the strong regulatory environment and low operating risks currently evident in Australia.[50]

On balance, the ACCC considers its use of an average ‘A’ credit rating for a benchmark TNSP, based on the statements of credit rating agencies and a sample of Australian electricity network companies, is consistent with the overall environment in which TNSPs operate.

Having established a credit rating, a debt margin can be determined. The debt margin should reflect the prevailing market rates for debt issues reflecting the benchmark maturity and credit rating for the regulated entity.

In previous revenue cap decisions, the ACCC has assumed a benchmark debt margin with a term equal to the regulatory period for the regulated entity. This position was consistent with the ACCC’s use of a risk-free rate matching the regulatory period. However, as discussed in section 4.4, the ACCC now recognises that the 10 year bond rate can be used as a proxy for the risk-free rate. To maintain consistency between the two cost of debt components, the ACCC considers that the benchmark term of the relevant corporate bond rate should match the term of the risk-free rate being used.

For this decision, the ACCC considers it is appropriate to reference the debt margin to the CBASpectrum benchmark which estimates a fair yield curve (of various terms and credit ratings) for Australian corporate bonds. The 10 day moving average benchmark debt margin over the government bond yields, for ‘A’ rated corporate bonds with a term of 10 years, is 90 basis points.[51] Consistent with calculating the risk-free rate, this has been adjusted to an effective annual compounding rate. Combined with the nominal risk-free rate of 5.98 per cent, it provides a nominal cost of debt of 6.88 per cent for use in the WACC estimate.

4.8 Debt raising costs

To raise debt, a company has to pay debt financing costs over and above the debt margin. Such costs are likely to vary between each debt issue, depending on the borrower, lender and market conditions.

The ACCC recently commissioned the Allen Consultancy Group (ACG) to consider the appropriateness of allowing transaction costs associated with debt and equity financing and to determine a benchmark allowance for these costs.[52] According to ACG the debt raising cost being considered should be the transaction cost of re-financing fixed rate bonds to the value of the notional gearing component of the

49 op cit, p. 1.

50 op cit p. 40.

51 CBASpectrum website: www.cbaspectrum.com

52 ACG, Debt and Equity Raising Transaction Costs – Report to the ACCC, December 2004.

TNSP's RAB (assuming a consistent benchmark credit rating). The allowed debt benchmark does not relate to:

- acquisitions by the regulated firm
- non-core construction or investment activities that are being undertaken.

Therefore the transaction costs associated with the benchmark cost of debt should not relate to activities outside of the re-financing of bonds for the regulated firm's core activities.[53]

EnergyAustralia proposed 12.5 basis points be allowed to account for debt raising costs.

4.8.1 Submissions

While EnergyAustralia supports the ACCC for recognising that debt issuance is a significant cost, it believes that the allowance for these costs in the draft decision understates the cost to the firm of issuing debt. NECG's report for EnergyAustralia shows that the empirical evidence that is available is consistent with a total debt issuance cost in the order of up to 0.50 per cent or 50 basis points. NECG notes that 25 basis points represent a more appropriate allowance at this time, although EnergyAustralia argues that its issuance costs are more likely to be in the range of an amount equivalent to 30 to 50 basis points.

4.8.2 ACCC's considerations

The ACCC considers that TNSPs should be provided a benchmark allowance for debt raising costs that reflects current market costs.

In its draft decision, the ACCC allowed debt raising costs of 10.5 basis points per annum (bppa). This allowance was based on advice provided by a number of commercial banks which indicated that debt raised on capital markets is likely to incur fees in the range of 8 to 12.5 bppa. The ACCC noted that the practice of allowing debt raising costs is relatively new in regulatory decisions. In the SRP, the ACCC also stated that it would undertake a further review of debt and equity raising costs.

In the recent consultancy undertaken by ACG, it concluded that debt raising costs were a legitimate expense that should be recovered through the revenues of the regulated utility.[54]

ACG considered that given transaction costs associated with debt would continue to be incurred for the whole value of the investment, the most appropriate means of recovering these costs would either be as an addition to the estimated WACC or as a direct allowance to operating expenses.

53 ibid., p. 5.

54 ibid., p. xiii.

ACG based its benchmark on debt raising costs applicable to Australian international bond issues or joint Australian market/international issues. In developing the benchmark, ACG calculated a gross underwriting fee benchmark of 5.5 bppa based on a 5 year term. To this, it added allowances for legal and roadshow expenses; credit rating fees for the firm and for each issue of bonds; and registry and paying charges. The build up of debt raising costs and total recommended benchmark for bond issues is shown in table 4.2.

Table 4.2 Benchmark debt raising costs for bond issues

Fee	Explanation/Source	1 issue	2 issues	4 issues	6 issues
Amount raised	Multiples of median bond issue size	$175m	$350m	$700m	$1,050m
Gross underwriting fees	Bloomberg for Aust. Intl. issues, tenor adjusted	5.5	5.5	5.5	5.5
Legal and roadshow	$75K–$100K: Industry sources	1.1	1.1	1.1	1.1
Company credit rating	$30K–$50K: S&P ratings	2.9	1.4	0.7	0.5
Issue credit rating	3.5 (2-5)bps up-front: S&P ratings	0.7	0.7	0.7	0.7
Registry fees	$3K per issue: Osborne Associates	0.2	0.2	0.2	0.2
Paying fees	$1/$1M quarterly: Osborne Associates	0.0	0.0	0.0	0.0
Total	Basis points per annum	10.4	9.0	8.2	8.0

Source:ACG Debt and Equity Raising Costs – Report to the ACCC, 2004, p xviii.

On the basis of the evidence provided by ACG, the ACCC considers it is appropriate to allow benchmark debt raising costs derived in accordance with the above table. EnergyAustralia has an opening RAB of $635.6m and the assumed benchmark gearing ratio is 60:40. This provides the notional debt component of the RAB to be around $381m ($635.6m × 0.6).

According to table 4.2, the overall debt size of this amount would require at least 2 issues. Therefore the ACCC considers an allowance of 9 bppa for debt raising costs is a reasonable benchmark for EnergyAustralia. The allowance for debt raising costs is about $0.36m per year on average over the regulatory period ($real 2003–04). This is included as part of opex (see chapter 5) because it is an identified cost category.

4.9 Market risk premium

The MRP is the margin above the risk-free rate of return that investors expect to earn if they held the market portfolio. That is, the return of the market as a whole minus the risk-free rate:

$$MRP = r_m - r_f$$

Under a classical taxation system, conventional thinking suggests a value for the MRP of around 6 per cent.

Determination of the return on capital for a regulated business is a forward looking process. However estimates of the future cost of equity are not readily available. Practical applications of the CAPM therefore rely on the analysis of historic returns to equity when estimating the MRP.

EnergyAustralia proposes an MRP of 6 per cent in its application. It argues that, given clear and well-established historical precedent, the most appropriate MRP to adopt is 7 per cent and there is no case for an MRP below 6.5 per cent. However, in the context of recent regulatory precedent and the alignment of regulators on this issue, EnergyAustralia recommends that an MRP of 6 per cent be adopted.

4.9.1 Submissions

The EMRF identifies various studies which indicate different levels of MRP. It believes that the transmission businesses seek higher levels of MRP because it will lead to higher WACCs and enhance the return to their shareholders. Equally, consumers would seek the lowest appropriate levels of MRP to minimise the WACC and pay less for the service.

The customers' group also believes the MRP of 6 per cent is too high. It suggests that recent studies and surveys indicate an MRP in the region of 4–5 per cent would more accurately reflect the Australian financial market.

Transend believes that the ACCC's views on the MRP reflect a reasonable and balanced judgement of the available evidence.

At the pre-decision conference held on the 18 June 2004, the customers' group questioned why the ACCC has not adopted an MRP similar to those used by UK regulators (around 3.5 per cent). EnergyAustralia argues against this by noting that a historical study of international MRP by Dimson, Marsh and Staunton reports that the UK MRP for 1900–2002 was 5.5 per cent.[55]

In EnergyAustralia's opinion, a value of 6 per cent is at the low end of a plausible range for the MRP. Historical estimates of MRP typically fall within a range of 6–8 per cent, while other approaches result in estimates of around 7 per cent. As a result, it believes it is impossible to conclude that a value below 6 per cent is justified.

55 Joint Customer Presentation, ACCC pre-determination conference, 18 June 2004.

4.9.2 ACCC's considerations

Although there is a substantial amount of research undertaken on the MRP, there is continuing debate as to the appropriate value. The ACCC notes that there is support for an MRP of 6 per cent in submissions received in response to the draft decision. However, arguments for lower values were also received from interested parties.

Historic measures

The rationale for using historical data as a measure of the expected MRP is that investors' expectations will be framed on the basis of their experience. The ACCC considers the value of the MRP, based on a traditional long term view using historic measures (ex-post measure), remains around 6 per cent.[56]

The ACCC notes the EMRF's comment that the MRP has fallen to around 3–4 per cent over recent years.[57] However, the ACCC is cautious that this may partially reflect short-term market trends. Further, statistical estimates over the shorter periods tend to provide standard errors which are typically higher than the mean estimates. This suggests that caution must accompany the interpretation of these results.

UK MRP and the ex ante method

The ACCC notes the UK regulators appear to use a forward looking MRP based on an ex ante (supply-side) approach. The ex ante approach estimates the MRP as the sum of the expected dividend yield and the expected capital gain from shares. The MRP estimates from an ex ante approach are generally lower than historic estimates of MRP. Australian applications of similar ex ante approaches have arrived at an estimate of 4–5.7 per cent.[58] A major part of the differential appears to be driven by the Australian assumption of a significantly higher long run growth in gross domestic product.

Most of the research on the ex ante approach has been undertaken in the USA market. Given the relatively limited research on the Australian application of the ex ante approach, the ACCC considers caution must accompany the interpretation of these results. Therefore the ACCC considers it is not appropriate to rely exclusively on the ex ante approach for the purposes of estimating a MRP.

Benchmarking of international data

An alternative approach for determining the Australian MRP is through the benchmarking of international data. A study by Bowman estimated the Australian MRP to be 7.8 per cent from using the benchmarking approach on the basis of:

- a USA MRP in the range of 6 to 9 per cent

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56 There appears to be consensus that the MRP cannot be easily predicted over shorter periods and is likely to have poor statistical properties.

57 Headberry Partners and Bob Lim, Further capital markets evidence in relation to the market risk premium and equity beta values-for ECCSA, December 2003, p. 48.

58 Lally, The Cost of Capital Under Dividend Imputation, June 2002, pp.29–34.

- making adjustments for incremental risk factors of 0.1 to 2.4 per cent on the USA MRP for differences in taxation, market differences, country risk and time horizon.[59]

The ACCC is cautious about this approach. Apart from the issues associated with estimating the USA MRP, the benchmarking approach also involves the estimation of adjustment factors which are arbitrary and add more doubt to the accuracy of the estimation.

Survey data

Another approach to determining the MRP is using survey data as referenced by the EMRF. The ACCC considers that there are problems associated with survey data because surveys are conducted at a specific point in time and may only reflect transient market sentiments. The reliability of survey data is also a concern. Common issues include obtaining a representative sample and framing the survey so as not to induce bias in respondents. Due to general concerns about the reliability of survey data, the ACCC will consider but tend not to place much weight on survey data.

Consultancies

A study undertaken by Associate Professor Lally, on behalf of the ACCC, assessed various approaches and estimates of the MRP. Lally determined that across four different approaches (including historic and ex ante methods) the average estimate for the MRP in Australia was 6.1 per cent.[60] He concluded that:

> …the range of methodologies examined give rise to a wide range of possible estimates for the market risk premium and these estimates embrace the current value of 6 %. Accordingly the continued use of the 6 % estimate is recommended.[61]

ACG has also reviewed the empirical evidence on the Australian MRP. Based on the evidence presented which includes an analysis of international trends in MRP, ACG concluded that:

> …there is no justification for applying an MRP different from 6 %, as is the practice of Australian regulators.[62]

The ACG noted that while the point estimate of the MRP provided by historical evidence suggests a higher figure, the qualitative and empirical evidence from ex ante models provide persuasive evidence that 6 per cent overstates the expected MRP.

4.9.3 ACCC's considerations

The ACCC considers that the information prepared by Lally and ACG demonstrate that 6 per cent is an appropriate balance of the available evidence on the MRP.

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59 ibid.

60 This average was derived using: historical averaging of the Ibbotson type (0.07); historical averaging of the Siegel type (0.056); the Merton methodology (0.07); and 0.04 – 0.057 from the forward looking approach with a point estimate of 0.048.

61 op. cit., p. 34.

62 ACG, Review of studies comparing international regulatory determinations, 2004, p. 113.

Although historical premiums typically suggest a higher MRP than 6 per cent, further estimates of the MRP over more recent periods and forward looking estimates typically suggest a lower MRP than 6 per cent. Therefore, for this decision, the ACCC will maintain its current estimate of 6 per cent for the MRP but will continue to monitor the available research.

4.10 Betas and risk

The equity beta is a measure of the expected volatility of a particular stock relative to the market portfolio. It measures the systematic risk of the stock, that is, the risk that cannot be eliminated in a balanced and diversified portfolio.

Generally, the Australian stock index is used as a proxy for the market portfolio. An equity beta of less than one indicates that the stock has a low systematic risk relative to the market (the market portfolio beta being equal to one). Conversely an equity beta of more than one indicates the stock has a high risk relative to the market.

Calculating equity betas for publicly listed companies is straightforward. A company's return is calculated by adding the dividend income to changes in the value of the stock. Then the company's return is compared to the market return. Market return is calculated in the same way, i.e. by adding the dividends and changes in values of all the companies listed on the Australian Stock Exchange (ASX).

Calculating equity betas for unlisted firms is more complicated as their returns cannot be calculated directly. Hence, conventional practice is to find the beta of a similar listed company or the average beta for the sector, and then adjust it.

For Australian regulated electricity networks even this approach is problematic, as very few similar stocks are listed.

The equity beta of a firm may also be dependent on its capital structure. Hence, to estimate the beta of a regulated firm, the beta of the comparable (listed) firm has to be adjusted for differences in capital structure.

Usually, practitioners start with the equity beta of a firm. Then by 'de-levering' it, to approximate a firm without debt (100 per cent equity), they arrive at the 'asset' or 'un-levered' beta.

The asset beta is common for all firms in a similar business. Equity beta for a particular level of gearing is obtained by 're-levering' the asset beta. While there are a number of levering formulae, the ACCC has considered that the formula developed by Monkhouse is appropriate given Australia's tax environment:

$$\beta e = \beta a + (\beta a - \beta d)\left[1 - \left(\frac{rd}{1+rd}\right)(1-\gamma)Te\right]\frac{D}{E}$$

where:

β_e	=	equity beta
β_a	=	asset beta

β_d	=	debt beta
r_d	=	cost of debt
γ	=	gamma
T_e	=	effective tax rate
E	=	market value of equity
D	=	market value of debt.

The debt beta captures the systematic risk of debt and is used to de/re-lever the equity beta. When converting asset betas to equity betas, one includes the systematic risk for debt in the capital structure. The debt beta shows the sharing of a firm's systematic risk between the systematic risk of equity and the systematic risk of debt.

In its application, EnergyAustralia adopts a debt beta of zero combined with an asset beta of 0.425 which provides a re-levered equity beta of 1.06. It argues that consideration of international beta values together with regulatory precedent suggests that an asset beta range of around 0.40–0.50 can be justified.

4.10.1 Submissions on the draft decision

The EMRF raised concerns regarding the ACCC's decision to adopt an equity beta of one. The EMRF believes that an equity beta lower than one is sufficient for regulated businesses. It believes that at the hearing involving the ACCC and GasNet in 2003, the ACCC offered very sound arguments that the equity beta should be no more than 0.7.

The customers' group states that the ACCC should rely more on market data in determining an estimate of the proxy equity beta. With the emergence of market data, the customers' group believes the ACCC is still reluctant to lower the equity beta. It would like to see the ACCC begin the process of removing bias against customers and lower the equity beta to, say 0.7 or 0.8, while continuing with its investigations.

Transend believes the ACCC's view on the equity beta reflects a reasonable and balanced judgement of the available evidence. However it is concerned that the ACCC is signalling its future intention to place greater weight on contemporary market information which, in Transend's view, indicates that a lower equity beta is appropriate. It believes that such comments suggest that regulatory risk is an on-going concern.

EnergyAustralia believes that the available evidence from the ASX does not support the ACCC's arguments for setting an equity beta for an electricity transmission company below one. Regardless of the arguments in relation to the systematic risk of TNSPs compared to other companies on the ASX, the systematic risk as measured by the asset beta is already significantly lower than that for an average firm on the ASX.

4.10.2 ACCC's considerations

Equity beta

The ACCC notes that in previous revenue cap decisions, an equity beta estimate of one was adopted. This suggests that the TNSP experiences the same volatility as the market portfolio in general. However, this is not consistent with the frequently held view that gas and electricity transmission businesses are less risky relative to the market, irrespective of their gearing. This view is predicated on the observation that the earnings of gas and electricity business are more stable than most other businesses in the market. Greater stability of cash flows suggests that the equity beta should be less than one.

In the SRP, the ACCC noted that market evidence shows regulated energy firms listed on the ASX have an equity beta of below one (after adjusting for gearing differences) and thus do not face the same market risk relative to the market portfolio beta.

Table 4.3 lists the equity betas for recent regulatory decisions by other jurisdictional regulators.

Table 4.3 Recent regulatory decisions on equity betas for electricity industry

Decision	Network Type	Equity Beta
IPART, NSW (2004)	Distribution	0.8–1.1
ICRC, ACT (2004)	Distribution	0.9
ESC, VIC (2000)	Distribution	1.0
QCA, QLD (2005 draft)	Distribution	0.9
ESCOSA, SA (2004 draft)	Distribution	0.8

Asset beta

The asset beta is only relevant within the de/re-levering process. The asset beta is simply the equity beta for a firm that is 100 per cent equity financed and has no debt in its capital structure. It is not observable and must be de-levered from the observed equity beta.

Debt beta

The ACCC notes that a debt beta estimate of zero has been applied in its previous electricity revenue cap decisions. The ACCC, in the past, considered that as the systematic risk of debt is low (given the risk of debt is primarily related to default risk) then a relatively low debt beta is appropriate and as such treated the debt beta as a residual parameter.

A report prepared by ACG for the ACCC considered this information and suggested that an appropriate range for the debt beta would be between zero and 0.15.[63]

Nonetheless, as long as there is consistency in the value of the debt beta between the de-levering and re-levering process, its effect on the equity beta is generally negligible.

63 ACG, Empirical evidence on proxy beta values for regulated gas transmission activities, final report for the ACCC, July 2002, pp. 28–29.

Beta and gearing of the market

The ACCC notes EnergyAustralia's comment about the firm's beta compared with the average firm listed on the ASX and the requirement to normalise the gearing. As stated in the SRP, this issue appears to be a misinterpretation of what an equity beta of one implies.[64] By definition, the market portfolio beta has a value of one and does not require any gearing assumption.

However, there are a number of factors which can affect the beta for a firm in the market portfolio.[65] Therefore, as illustrated below, the practice is to pool a sample of comparable firms which would normalise these factors affecting the beta as much as possible. Gearing is assumed to be the remaining factor for adjustment and this is undertaken in the de-levering/re-levering process.

Estimating equity beta from market data

The ACG report suggested an equity beta for Australian gas transmission companies of just below 0.7 based exclusively on market evidence.[66] ACG also considered data for comparable businesses in the USA, Canada and UK. This data produced lower beta estimates and ACG concluded that this secondary information supports the view that Australian estimates are not understated. However, due to several qualifications to their analysis, ACG did not recommend relying only upon domestic empirical information.

ACG recommended that a conservative approach to beta estimation be retained by Australian regulators with an equity beta estimate of one. ACG however, noted that:

> In the future, however, it should be possible for greater reliance to be placed upon market evidence when deriving a proxy beta for regulated Australian gas transmission activities.[67]

As shown in table 4.4, the ACCC has derived re-levered equity betas for five comparable Australian firms[68] based on September 2004 and December 2004 data from the Australian Graduate School of Management (AGSM).[69] For calculation purposes, the ACCC has had regard to raw (unadjusted) beta estimates, the debt beta was set at zero, and the corresponding gearing levels were from Standard and Poor's.[70] The sample market beta estimates (average re-levered beta of 0.20 in September 2004 and average re-levered beta of 0.24 in December 2004) suggest that the ACCC has

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64 op. cit., p. 106-107.

65 Such factors can include: nature of the firm's output; duration of contracts; regulation; monopoly power; operating leverage; real options; industry size; capital structure.

66 op. cit., p. 46.

67 op. cit., p. 43.

68 These firms are comparable because they operate in a similar line of business (regulated networks) as the target firm such that the systematic risk of the underlying assets is likely to be of similar magnitude. It should be noted that some of these firms are involved in other business areas (non-regulated) which is likely to overstate the systematic risk of a target regulated network firm.

69 AGSM uses monthly observations over 48 months of the firm's trading history (with a minimum of 20 observations).

70 Standard & Poor's, Australia & New Zealand CreditStats, June 2004.

been conservative with its estimate of the equity beta in its previous regulatory decisions.

Table 4.4 Comparable sample betas

		September 2004 AGSM data			December 2004 AGSM data		
Company	**Gearing level**	**Unadjusted β_e**	**De-levered β_a**	**Re-levered β_e**	**Unadjusted β_e**	**De-levered β_a**	**Re-levered β_e**
Australian Pipeline Trust	66.4	0.3	0.1	0.3	0.4	0.2	0.4
Envestra	80.8	0.4	0.1	0.2	0.4	0.1	0.2
AlintaGas	56.2	0.4	0.2	0.5	0.4	0.2	0.4
Australian Gas Light	36.5	-0.0	-0.0	-0.0	0.0	0.0	0.1
GasNet	68.9	0.1	0.0	0.1	0.2	0.1	0.1
Average	**61.8**	**0.3**	**1.0**	**0.2**	**0.3**	**0.1**	**0.2**

In the SRP, the ACCC stated that emerging market data suggested the appropriate equity beta for TNSPs may be less than one.[71] The ACCC also stated that it would continue to undertake further work in this area.

The ACCC considers current statistical methods for estimating the equity beta from market data tend to produce varying confidence interval (and sample average) estimates. In this context, the ACCC notes that recent jurisdictional regulatory decisions provided analysis of a comparable sample of equity betas based on monthly and weekly observations which produced different results.[72][73] The analysis indicates that the weekly beta estimates tend to be higher than the monthly beta estimates.

The ACCC also notes that the estimated re-levered equity betas for comparable firms have fallen from around one in 2000 to around 0.2 in 2003.[74] This is consistent with the ACCC's estimates of market derived equity betas considered in recent regulatory decisions. The ACCC considers that the time period of the market data is not long enough to satisfy the concern that market derived equity betas would not systematically under compensate the TNSPs. That is, the current decline in the measures of beta from market evidence may reflect a short term deviation from normal trend.

71 op. cit., pp. 107–108.

72 ESCOSA, 2005-2010 Electricity Distribution Price Determination Part A-Statement of Reasons, April 2005, pp.138-140.

73 QCA, Regulation of Electricity Distribution-Draft Determination, December 2004, pp. 102–103.

74 op. cit., p. 140.

For these reasons, the ACCC considers it is appropriate to continue with exercising judgement in the application of empirical evidence from the market and to maintain using an equity beta value of one. On balance, the ACCC considers that an equity beta of one, while biased in favour of the service provider, is appropriate for EnergyAustralia.[75]

4.10.3 ACCC's considerations

EnergyAustralia's proposed equity beta of 1.06 suggests that it has a higher risk relative to the market portfolio. In previous electricity regulatory decisions, the ACCC has consistently applied an equity beta of one.

For the purposes of this decision, the ACCC has decided to adopt a conservative equity beta value of one. The ACCC considers an equity beta of one adequately compensates EnergyAustralia for its systematic risk. However, in future decisions, the ACCC may place greater weight on contemporary market information in determining appropriate beta values.

4.11 Gearing

The ACCC uses benchmark gearing in determining the WACC, rather than the actual gearing. Schedule 6.1(5.5.1) of the code states that:

> Gearing should not affect a government trading enterprise's target rate of return … For practical ranges of capital structure (say less than 80 per cent debt), the required rate of return on total assets for a government trading enterprise should not be affected by changing debt to equity ratios.

EnergyAustralia adopts the ACCC's benchmark gearing of 60 per cent in its application.

4.11.1 ACCC's considerations

In determining a required rate of return, the ACCC adopts the accepted practice of calculating the WACC based on a capital structure of equity and debt financing. Therefore a gearing ratio is needed to establish a TNSP's appropriate weighted average cost of debt and equity. The ACCC can choose the actual gearing of the service provider or an appropriate benchmark.

The ACCC's regulatory regime is both light-handed and incentive based. It sets the benchmarks allowing regulated entities to operate freely. The entities gain by performing better than the benchmarks and conversely lose when performing lower than the benchmarks. Accordingly, in the SRP the ACCC stated that it would not be using the actual gearing of a TNSP, but an appropriate benchmark instead.

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75 The equity beta of one is not re-levered from a debt beta of zero and an asset beta of 0.4. There were no comparable Australian market based data on equity betas which re-levered to an asset beta of 0.4.

A firm's capital structure (expressed as gearing) is unlikely to affect its WACC according to the theory developed by Modigliani and Miller. However, this theory is based on specific assumptions and is only true where the risk of the total assets does not change and hence neither does the cost of capital for the firm's assets.

Typically regulators have assumed a gearing of 60 per cent in calculating the WACC. This WACC should still be applicable within reasonable range of actual gearing, say 40-70 per cent.[76]

The ACCC notes that a survey conducted by Standard and Poor's suggested gearing ratios for transmission and distribution businesses are between 55 and 65 per cent.[77]

Further, as set out in table 4.1 the ACCC's sample of ten electricity network companies provides an average gearing level of 57 per cent. A larger sampling of electricity network companies (table 4.5) also shows an average gearing of approximately 57 per cent which is close to the assumed benchmark gearing of 60 per cent.[78]

Table 4.5 Gearing of electricity companies

Company	Actual Gearing (%)
Aurora Energy	52.0
Australian Gas Light	40.8
Citipower Trust	54.1
Country Energy	68.3
ElectraNet	71.9
Energex	55.3
EnergyAustralia	51.4
Ergon Energy	49.3
ETSA Utilities	63.5
Integral Energy	51.3
Powercor Australia	38.1
SPI PowerNet	76.8
TransGrid	55.3
Western Power	62.5
Average	**56.5**

Source: Standard and Poor's, *Australian Report Card Utilities*, October 2004.
Standard and Poor's, Australia and New Zealand CreditStats, June 2004.

76 Officer, A Weighted Average Cost of Capital for a Benchmark Australian Electricity Transmission Business-A Report for SPI PowerNet, February 2002, p. 38.

77 Standard and Poor's, Rating Methodology for Global Power Companies, 1999.

78 The electricity companies listed in the table are not only operating in the regulated transmission and distribution sectors but some also operate in unregulated areas such as retail and generation.

On balance, given the average level of gearing in the electricity network industry, the ACCC is will adopt a benchmark gearing of 60 per cent.

4.12 Value of franking credits

Australia has a full imputation tax system under which a proportion of the tax paid by a company is, in effect, personal tax withheld at the company level.

The analysis of imputation credits and their impact on cost of capital in Australia is a developing field. The rate of use of tax credits or gamma (γ) may have an effect on the WACC (where a TNSP actually pays tax) and there is little doubt that franking credits have value (schedule 6.1(5.2) of the code):

> As the ultimate owners of government business enterprises, tax payers would value their equity (and post corporate tax cash flows) on exactly the same basis as they would value an investment in any other corporate tax paying entity. On this basis, it would be reasonable to assume the average franking credit value (of 50%) in the calculation of the network owner's pre-tax WACC.

EnergyAustralia proposes the continued use of 0.5 for γ. It acknowledges that a point in the range between 0.30 and 0.50 for γ is well established in Australian regulatory decision making.

4.12.1 ACCC's considerations

The γ parameter incorporates dividend payouts carrying imputation credits and the proportion of those credits that could be used. The ACCC has previously noted that there is no well founded basis for discriminating the selection of γ in favour of one type of investor over another. Such an approach may distort pricing outcomes on the basis of share ownership and would not take into account other tax advantages or disadvantages that may be available to investors.

There does not seem to be consensus among Australian academics and finance practitioners about the rate of use of imputation credits. Having regard to empirical evidence and given that the value of γ lies between zero and one, the ACCC will continue to use a γ of 0.5.

4.13 Treatment of taxation

The effective tax rate is defined as the difference between pre-tax and post-tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that lessen or defer tax liabilities. Although the tax rate on accounting income is always at the corporate rate, in any year the income assessable for tax purposes can be quite different from the net revenues available to the business.

The timing aspect and the fact that taxes are assessed on the basis of nominal income means that the prevailing inflation rate also has a significant impact on the effective tax rate.

In its early decisions, the ACCC applied the statutory company tax rate of 30 per cent. This was in the context of difficulties in determining an accurate long-term tax rate as part of the pre-tax real framework being used at the time. However, the capital-intensive nature of electricity utilities has historically meant that the effective tax rate for such networks has been less than the statutory tax rate.[79]

The ACCC considers that adopting the post-tax nominal framework which uses the effective tax rate can potentially generate more appropriate cost reflective revenue caps.

4.13.1 ACCC's considerations

Based on the ACCC's approach to modelling the effective tax rate, the ACCC has derived an effective tax rate of 28.61 per cent.

4.14 Summary

In considering the values to adopt for EnergyAustralia's cost of capital, the ACCC has considered EnergyAustralia's application, the submissions received by interested parties on the application, as well as the submissions received on the ACCC's draft decision. The ACCC has carefully considered the values that should be assigned to EnergyAustralia's cost of capital, given the nature of its business and current financial circumstances. The parameter values adopted for this decision are shown in table 4.6.

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79 According to IPART calculations, the average effective tax rate paid by the NSW distributors amounted to 25 per cent in 1996–97 (see IPART, *The Rate of Return of Electricity Distribution Network - Discussion Paper*, November 1998, p. 9).

Table 4.6 Comparison of cost of capital parameters

Parameter	ACCC decision	ACCC draft decision	EnergyAustralia's proposal
Nominal risk-free interest rate (rf)	5.98 %	5.89 %	5.55 %
Real risk-free interest rate (rrf)	3.41 %	3.37 %	3.34 %
Expected inflation rate (f)	2.49 %	2.44 %	2.14 %
Debt margin (over rf)	0.90 %	0.87 %	1.475 %
Cost of debt rd = rf + debt margin	6.88 %	6.76 %	7.025 %
Market risk premium (rm-rf)	6.00 %	6.00 %	6.00 %
Gearing (D/V)	60 %	60 %	60 %
Value of imputation credits γ	50 %	50 %	50 %
Asset beta βa	-	0.40	0.425
Debt beta βd	-	0.00	0.00
Equity beta βe	1.00	1.00	1.06
Nominal post-tax return on equity	11.98 %	11.86 %	11.89 %
Post-tax nominal WACC	6.94 %	6.84 %	6.95 %
Pre-tax real WACC	7.06 %	6.94 %	7.47 %
Nominal vanilla WACC	8.92 %	8.80 %	8.97 %

5 Operating and maintenance expenditure

5.1 Introduction

In using the building block model to set EnergyAustralia's MAR the ACCC determines an allowance for opex.

This chapter sets out:

- the requirements of the code in section 5.2
- EnergyAustralia's application in section 5.3
- the draft decision in section 5.4
- submissions on the draft decision in section 5.5
- the ACCC's framework for determining the opex allowance in section 5.6
- the ACCC's approach to the starting point for forecast opex in section 5.7
- the ACCC's considerations of cost drivers which impact on forecast opex requirements over the regulatory period in section 5.8
- the ACCC's considerations in relation to a working capital allowance in section 5.9
- the ACCC's approach to the use of benchmarking in this decision in section 5.10
- a summary of the ACCC's decision in section 5.11.

5.2 Code requirements

Clause 6.2.4(a) of the code provides that economic regulation is to be of the CPI-X form (or some incentive-based variant). In setting a revenue cap, the ACCC is required to take into account the TNSP's revenue requirements during the regulatory control period, having regard for, amongst other things:

- the ACCC's reasonable judgment of the potential for efficiency gains to be realised by the TNSP in expected operating, maintenance and capital costs, taking into account expected demand growth and service standards[80]
- the on-going commercial viability of the transmission industry.[81]

80 National Electricity Code Administrator, National Electricity Code, clause 6.2.4(c)(3). See also clauses 6.2.4(c)(1) and (2).

Under clause 6.2.3, the regulatory regime administered by the ACCC must have regard to the need to, amongst other things:

- provide TNSPs with incentives and reasonable opportunities to increase efficiency[82]
- provide a fair and reasonable risk-adjusted cash flow rate of return to TNSPs on efficient investment given efficient operating and maintenance practices[83]
- provide reasonable certainty and consistency over time of the outcomes of regulatory processes, having regard for the need to balance the interests of users and TNSPs[84] and to minimise the economic cost of regulatory actions and uncertainty.[85]

Clause 6.2.2 provides that the regulatory regime must seek to achieve certain outcomes including:

- an efficient and cost-effective regulatory environment[86]
- an incentive-based regulatory regime which provides an equitable allocation between users and TNSPs of efficiency gains reasonably expected by the ACCC to be achievable by the TNSP[87]
- an incentive-based regulatory regime which provides for a sustainable commercial revenue stream which includes a fair and reasonable rate of return to TNSPs on efficient investment, given efficient operating and maintenance practices[88]
- prevention of monopoly rent extraction by TNSPs[89]
- an environment which fosters efficient operating and maintenance practices within the transmission sector[90]
- reasonable regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions[91]

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81 ibid., clause 6.2.4(c)(8).

82 ibid., clause 6.2.3(d)(1).

83 ibid., clause 6.2.3(d)(4).

84 ibid., clause 6.2.3(d)(5)(i).

85 ibid., clause 6.2.3(d)(5)(iii).

86 ibid., clause 6.2.2(a).

87 ibid., clause 6.2.2(b)(1).

88 ibid., clause 6.2.2(b)(2).

89 ibid., clause 6.2.2(c).

90 ibid., clause 6.2.2(e)

91 ibid., clause 6.2.2(i).

- reasonable certainty and consistency over time of the outcomes of regulatory processes[92]

- reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of TNSPs, users and the public interest.[93]

5.3 EnergyAustralia's application

EnergyAustralia put forward a proposal for opex that reflects changes in its transmission asset base, changes in the methodology for estimating opex requirements, the impact of asset age and a move from time based to reliability centred maintenance (RCM). Further EnergyAustralia notes that changes in the regulatory environment (occupational health and safety (OH&S) and environmental regulations), and increases in insurance and superannuation costs have all placed upward pressure on opex requirements.

EnergyAustralia has proposed total opex of $24.4m in 2004–05 increasing in real terms to $27.7m by 2008–09, as show in the Table 5.1. This proposed opex requirement has been developed taking into account the increased amount of transmission assets and using the revised allocation of opex by asset class (see section 5.4.1). EnergyAustralia's proposed opex for 2004–05 represents a step increase of around 13 per cent over its forecast opex for 2003–04, and a 39 per cent increase when compared to the opex approved by the ACCC for 2003–04.

Table 5.1 EnergyAustralia's proposed total opex

($m 2003–04)	04–05	05–06	06–07	07–08	08–09	Total
Maintenance expenditure	13.3	14.5	15.7	16.9	18.2	78.6
Other	11.1	11.2	10.8	10.3	9.5	52.9
Total	**24.4**	**25.8**	**26.6**	**27.1**	**27.7**	**131.6**

Source: EnergyAustralia's application, attachment G (allocation between maintenance and other varies throughout EnergyAustralia's application, but the total remains the same).

EnergyAustralia claims the ageing of its asset base and relatively low levels of replacement capex in the 1999–2004 regulatory period are both factors that contribute to increasing opex requirements in the 2004–2009 regulatory period.

EnergyAustralia also stresses the ongoing importance of the change to RCM, which has involved establishment costs, noting that savings from the change to RCM are not likely to be realised in the short term due to the increasing age of its transmission assets.

92 ibid., clause 6.2.2(j).

93 ibid., clause 6.2.2(k).

Further, EnergyAustralia notes that the change to RCM has facilitated a more reliable methodology for allocating opex between distribution and transmission assets. This new allocation framework uses asset category as a basis for allocation and EnergyAustralia states that it provides a far more accurate basis for identifying maintenance costs by asset class and allocating remaining shared costs between distribution and transmission assets.

5.3.1 Submissions on EnergyAustralia's application

The EMRF states that it is unable to obtain data on actual opex for the transmission network in relation to the 1999–2004 regulatory period. The EMRF expects the ACCC to require its consultants to review the efficiency of actual and forecast opex.

The EMRF further notes that partial productivity measures for the transmission network (such as opex per customer and opex per MWh) should be benchmarked against other comparable networks.

The customers' group expresses strong concerns about EnergyAustralia's proposed opex, suggesting that EnergyAustralia may be over estimating its actual requirement.

5.4 Draft decision

In its draft decision the ACCC implemented GHD's recommendations to modify EnergyAustralia's proposed opex to reflect a new efficient starting point. The ACCC then obtained a reasonable opex allowance by adjusting for the impact of efficiency cost drivers, which included the confidential project, IT, self insurance and debt raising costs.

These adjustments and the ACCC's proposed opex allowance are set out in table 5.2.

Table 5.2 EnergyAustralia's opex

($m 2003–04)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's proposal[(a)]	24.4	25.8	26.6	27.1	27.7	131.6
less: starting point variation ($2.04)	22.3	23.7	24.5	25.1	25.7	121.4
less: cost driver variation						
confidential project	0.1	(1.4)	(1.4)	(1.4)	(1.4)	(5.6)
IT	(0.7)	(0.7)	(0.7)	(0.8)	(0.8)	(3.6)
self insurance	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.10)
add debt raising cost	0.4	0.4	0.4	0.4	0.4	2.1
ACCC proposed opex	**22.1**	**22.0**	**22.8**	**23.3**	**23.9**	**114.1**

(a) EnergyAustralia's opex forecasts do not include debt raising costs as they were included in its WACC calculations.

The ACCC also considered that comparisons based on a single benchmark indicator are not very meaningful. Nonetheless, it stated that different indicators used in combination can help to assess whether a TNSP's opex is reasonable. The ACCC undertook its own benchmarking using several different ratios such as: opex per asset base; opex per line length (circuit kilometres); opex per substation; opex per gigawatt hour; and opex per megawatt.

5.5 Submissions on the draft decision

EnergyAustralia raised the following matters regarding the ACCC's opex review:

- the transfer of distribution assets to transmission assets from 1 July 2004 has resulted in an increase in its operating program, which has not been compensated for in the future operating cost program
- the review done by the ACCC and GHD was not detailed enough and resulted in the starting point of future opex being based on historical expenditures, which ignores that more activity is needed to be undertaken in the future
- applying a general efficiency factor for future expenditures without providing evidence as to the reasons for the reductions or the impacts the cuts may have is not acceptable
- GHD has taken into account superannuation costs that include EnergyAustralia's distribution, retail and external businesses, which are not subject to this review. EnergyAustralia states that the ACCC's approach of not recognising the full costs of superannuation is a concern
- cuts to IT expenditure are not appropriate given GHD's criticism of the systems currently in place and EnergyAustralia's need for the expenditure to ensure the business is able to meet its regulatory, safety and financial obligations
- The ACCC has under-compensated EnergyAustralia for current insured risks by including them as a pass through item rather than providing the requested allowance of $20,000 per annum as part of its opex.

Benchmark Economics discussed the opex/assets ratios that measure the effect of the operating environment on cost, not managerial efficiency. It notes that each of the ratios selected reflects the operating conditions for the particular network. It questions whether the regulated opex allowances given for those ratios truly reflect the underlying asset base. It believes that there is risk attached to the approach taken by the ACCC and it is not possible to determine whether the expenditures allowed are adequate.

Benchmark Economics also raised concerns about using EnergyAustralia's past opex as a guide for its future opex. It believes that, with the replacement capex allowance provided in the draft decision the average age of assets will increase over the regulatory period, and that opex could be expected to rise in line with the age of the asset base.

The EMRF has the following comments regarding EnergyAustralia's opex:

- it agrees with the proposed 1999–2004 regulatory period adjustments in superannuation, Olympics, insurance and productivity gains
- there is little justification to support EnergyAustralia's forecast opex
- the ACCC approach to opex is not supported as it implicitly accepts the claim by EnergyAustralia, which includes for a major cost increase without providing any benefit
- opex should be set using the past 5 year average as a starting basis.

5.6 Framework for EnergyAustralia's opex allowance

EnergyAustralia's proposed opex is used as the basis for the opex allowance estimated by the ACCC. The ACCC makes two key adjustments to EnergyAustralia's proposed opex: a starting point adjustment and a further adjustment for specific cost drivers.

In order to judge whether or not EnergyAustralia's proposed opex requirement and hence operating and maintenance practices are efficient, the ACCC needs to be confident of the starting point for future expenditures. The ACCC has determined a starting point based on a review of EnergyAustralia's opex in the 1999–2004 regulatory period. The starting point also reflects adjustments required because of changes to EnergyAustralia's transmission RAB and changes to its allocation methodology for estimating transmission opex.

The opex allowance for the 2004–2009 regulatory period is then calculated using EnergyAustralia's proposed opex, adjusted for specific efficiency savings identified by the ACCC.

5.7 Opex 1999–2004 regulatory period

GHD was engaged to review EnergyAustralia's opex in the 1999–2004 regulatory period, with a view to providing the ACCC with guidance about the reasonableness of both the opex starting point and path for the 2004–2009 regulatory period.

As with capex, the dual nature of EnergyAustralia's network business (distribution and transmission) and the availability of data constrained GHD's ability to make recommendations to the ACCC.

When EnergyAustralia's 1999–2004 revenue cap decision was being determined by the ACCC, EnergyAustralia had a limited ability to provide an accurate estimate of the transmission component of its network operating costs. As a result, EnergyAustralia estimated these costs via a global allocation based on the proportion of the replacement cost of transmission assets relative to total network assets. The results of the global allocation framework are shown in the table 5.3.

Table 5.3 Approved and actual opex for 1999–2004

($m nominal)	99–00	00–01	01–02	02–03	03–04	Total
Opex approved in 1999 decision	16.5	16.7	17.0	17.3	17.5	84.9
Actual opex	20.9	24.4	29.3	27.1	19.0[(a)]	120.7
Overspend	**4.5**	**7.7**	**12.3**	**9.9**	**1.5**	**35.8**

(a) Forecast based on original definition of transmission assets and revised asset class allocation framework.

GHD was asked to judge whether EnergyAustralia's expenditures over and above the amount allowed in the 1999–2004 decision represented efficient opex, for the purpose of determining a reasonable starting point and projecting a suitable path for opex in the 2004–2009 regulatory period. To do this, GHD had to determine how much was actually spent by EnergyAustralia on opex for transmission assets. This amount cannot be determined exactly as EnergyAustralia does not keep expenditure records at that level of detail. The data limitations led GHD to approach this task by considering total network opex (distribution and transmission) for EnergyAustralia, reviewing the cost drivers that impact on opex, and allocating resultant efficiencies to transmission. The allocation methodology and significant cost drivers are discussed below.

The purpose of examining the cost drivers is to determine what an efficient amount of opex for transmission would have been in each of the years in the 1999–2004 regulatory period and hence to provide a starting point from which to assess the efficiency of EnergyAustralia's forecast opex for the 2004–2009 regulatory period.

5.7.1 Allocation methodology

This section describes how EnergyAustralia's opex is allocated between the two elements of its network business. It is necessary to use an allocation methodology as EnergyAustralia operates it network businesses as a whole. EnergyAustralia has revised its allocation framework from a global allocation to an allocation based on asset classes.

For the purposes of determining how much EnergyAustralia spent on opex for transmission assets, three sets of data exist for the 1999–2004 regulatory period. The data reflects different allocation frameworks, and different definitions of transmission assets. It is important to bear in mind that despite the historical nature of these measures, all three are approximations and the 'true transmission opex' cannot be determined for the reasons outlined above. The three sets of data are as follows.

- Original opex: based on the original definition of transmission assets agreed by the ACCC in 1998, and apportioned using a global allocation framework.
- Amended opex: based on the original definition of transmission assets agreed by the ACCC in 1998, and apportioned using an asset class allocation framework.
- New opex: based on the new definition of transmission assets agreed to by the ACCC in 2003 and apportioned using an asset class allocation framework.

EnergyAustralia has provided estimates of opex using each of these definitions, as shown in table 5.4. In each case the estimate of actual expenditures is significantly greater than the approved opex allowed in the ACCC's 1999–2004 revenue cap decision. The average difference as a percentage using the original opex definition (global allocation framework) is 51 per cent, much higher than the 12 per cent average difference using the amended opex definition (asset class allocation framework).

Table 5.4 Approved and actual opex by definition

($m nominal)	99–00	00–01	01–02	02–03	03–04
Approved 1999 decision[(a)]	16.5	16.7	17.0	17.3	17.5
Original opex actual[(a)] (difference)	20.9 (4.5)	24.4 (7.7)	29.3 (12.3)	27.1 (9.9)	N/A
Amended opex actual[(b)] (difference)	17.5 (1.1)	19.2 (2.5)	19.1 (2.1)	19.3 (2.1)	19.0 (1.5)
New opex actual[(c)] (difference)	19.7 (3.3)	21.8 (5.1)	21.7 (4.7)	21.7 (4.4)	21.6 (4.1)

(a) Based on original definition of transmission assets and global allocation framework.
(b) Based on original definition of transmission assets and revised asset class allocation framework.
(c) Based on new definition of transmission assets and revised asset class allocation framework.

GHD contends that the most appropriate definition of opex to use when reviewing past opex is the definition used at the time of the ACCC's 1999–2004 revenue cap decision. That is, the original definition of transmission assets and the global allocation framework. In making this choice GHD states that it enables them to compare like with like, as required under the terms of reference, and notes that the ACCC's 1999–2004 revenue cap decision may well have been different if a different allocation framework or definition of transmission assets was used.

The ACCC agrees with GHD and considers that the review of opex for the 1999–2004 regulatory period must be undertaken using the same definition of transmission assets and cost allocation methodology that was used at the time of the 1999–2004 revenue cap decision. If a different definition was used, the ACCC would be considering the efficiency of EnergyAustralia's opex by comparing forecast opex on one set of assets with actual opex on a different set of assets. This would inevitably lead to a less accurate outcome than that which would be achieved by comparing forecast and actual opex on the same class of assets.

5.7.2 Opex cost drivers

This section considers specific cost drivers over the 1999–2004 regulatory period. These cost drivers are taken into account in setting the opex starting point for the 2004–2009 regulatory period.

Two submissions make comments on the approach adopted by the ACCC in setting a starting point based on historic opex spending. EnergyAustralia argues that determining the starting point for future opex through analysis of past opex does not take into account its view that greater levels of opex spending will be needed in the future.

Similarly Benchmark Economics does not support using EnergyAustralia's past opex as a guide for its future opex. It believes that opex would rise in line with the age of the asset base.

Superannuation costs

EnergyAustralia's total network opex for the 1999–2004 regulatory period includes superannuation costs of over $78m in the years 2000–2003. GHD states that such expenditures should not be considered as opex but should be treated as extraordinary expenses. GHD recommends adjustments to EnergyAustralia's transmission opex as set out in table 5.5.

GHD states that the recommended variation includes an adjustment for smoothing, which is intended to ensure that the data better reflects a suitable level of expenditure for EnergyAustralia going forward.

Table 5.5 GHD's recommended superannuation opex adjustments

($m 2003 – 04)	00–01	01–02	02–03
Superannuation impact on transmission opex	1.8	4.4	1.9
Recommended variation	**+0.1**	**-2.5**	**-0.1**

Source: GHD, EnergyAustralia Regulatory Review Report, Table 17, p. 61.

The ACCC also notes that EnergyAustralia's annual report shows a marked increase in superannuation expenditure (excluding abnormal items) over the 1999–2004 regulatory period, up from around $3m in 1999–00 to $23m in 2002–03.

Further information from EnergyAustralia shows that the increase is due to variations in fund earnings, where many of EnergyAustralia's employees are in defined benefit superannuation funds. Combined with increasing employee numbers and employer contributions of nine per cent, EnergyAustralia contends that the superannuation increases are consistent with their legal obligations.

EnergyAustralia supports GHD's proposed treatment of superannuation expenses as producing a more appropriate starting point for future opex expenditure.

The ACCC will adopt GHD's recommended adjustment to superannuation, accepting EnergyAustralia's claims that the increases are due to fluctuations in actuarially determined liabilities for defined benefit superannuation schemes.

Olympics

EnergyAustralia's annual report provides information about its involvement as a sponsor of the Sydney 2000 Olympic Games and the additional costs involved in ensuring uninterrupted supply during that period. GHD argues that the sponsorship money and time spent should be viewed as a donation rather than opex. However, GHD could not accurately identify the amount inappropriately charged to maintenance, beyond noting a real increase of around $3m in the years 1999–00 and 2000–01.

GHD suggests that opex for each of the relevant two years could be reduced by an amount in the range $0–$3m (i.e. $0 to $6m in total). The ACCC agrees with GHD and has decided to adjust opex by $3m in total over the two years. When allocated to transmission the adjustment equals $0.202m in 1999–00 and $0.098m in 2000–01. Without further information the ACCC has opted to make this adjustment as it is the mid-range of possible adjustments suggested by GHD.

Purchasing policies

EnergyAustralia has previously used a purchasing policy that sourced plant and equipment from the cheapest supplier. Such a policy has long term costs, in terms of increased ongoing costs for spare parts, increased costs of maintaining skills and training of staff for ongoing maintenance of a large variety of plant and equipment. EnergyAustralia claims that as the cost of the previous purchasing policy has become known, changes have been implemented to better standardise parts and equipment. This change in policy should introduce ongoing cost efficiencies and EnergyAustralia has included expected efficiencies in its proposed opex.

GHD states that it is unable to determine the costs of the previous purchasing policy, but estimates savings of around 1 per cent per annum should have been possible. GHD considers that these costs should be disallowed.

EnergyAustralia's response to the draft decision argues that past purchasing policies were prudent, and its current approach to purchasing is efficient. EnergyAustralia notes that it is acting as a prudent business when reviewing purchasing policies to ensure that the most efficient purchases are being made.

The ACCC agrees with EnergyAustralia and believes that any efficiency adjustment to the past opex levels will act as a disincentive to EnergyAustralia for future purchasing policy review. The fact that EnergyAustralia has updated its purchasing policies does not automatically mean that the old policies must be viewed as inefficient at the time they were implemented. The ACCC has decided not to make any specific adjustment to EnergyAustralia's opex with respect to EnergyAustralia's review of purchasing policies.

Insurance

Increasing insurance costs have impacted on Australian businesses since 2001, reflecting increased risk premiums following the September 11 terrorist attacks in the United States of America. EnergyAustralia is no exception, showing a step increase in insurance costs from $0.8m in 2000–01 to $6.6m in 2001–02, which then reduced to around $3.2m in 2002–03.

GHD, in its report:

> ...deem all years with the exception of 2001/02 as prudent, and would have expected a prudent organisation to have minimised the almost 9-fold increase in that year. A reasonable

> expenditure level in 2001/02, in line with the step increase that would have been experienced due to the September 11 attack would be equivalent to the 2002/03 expenditure.[94]

GHD recognises that increased insurance costs are expected but believe the size of the insurance expenditure in 2001–02 is too high, given the reduced expenditure in the following year. GHD has estimated that 2001–02 insurance costs should have been equivalent to 2002–03 costs ($3.19m) and have recommended a reduction in allocated transmission opex of $0.34m.

Further the ACCC notes that insurance expenses for other NSW electricity businesses did not show the same fluctuations, suggesting that EnergyAustralia's cost increases may have been driven by factors beyond the September 11 terrorist event.[95]

EnergyAustralia's response to the draft decision explains that the collapse of HIH was a major factor in the 2001–02 insurance cost increase. EnergyAustralia claims that an independent actuarial estimate recommended a provision of $8.6m for expenses relating to the collapse of HIH. EnergyAustralia states that around $5.1m of this provision related to the network business.

The ACCC has reviewed EnergyAustralia's additional information and accepts that no adjustment to past opex is necessary.

OH&S and environmental legislation

EnergyAustralia's application details the impact of the changes to the regulatory environment on their opex. GHD notes that such changes impact on many organisations and in the case of environmental legislation, the data provided is deemed comparable with other organisations. The ACCC has not made any adjustment to these estimates.

Consolidation of EnergyAustralia

EnergyAustralia has made efficiency savings of 3.5 per cent through corporate restructuring, which are incorporated in its opex claim. In its draft decision the ACCC notes continued efficiency savings may be possible as EnergyAustralia continues with the process of integration of systems and rationalisation of organisation structures that have arisen through the merging of different organisations to form EnergyAustralia.

EnergyAustralia has argued that future efficiencies are unlikely as the consolidation of various organisations that led to the creation of EnergyAustralia is unlikely to occur again.

The ACCC notes EnergyAustralia's position and will not make any specific adjustment for efficiency gains from integration and rationalisation of the organisation.

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94 GHD, EnergyAustralia Regulatory Review Report, p. 62.

95 TransGrid annual reports 2001, 2002 and 2003 and Integral Energy annual reports 2002 and 2003.

Full retail contestability

GHD notes that the costs associated with full retail contestability (FRC) were incorporated into the ‘other’ category, and according to SKM were to be reduced to zero by 2002–03. However, GHD did not find evidence of this and could not determine whether the costs were efficient.

Information provided by EnergyAustralia in response to the draft decision has clarified the treatment of FRC costs. The ACCC has reviewed EnergyAustralia’s opex allocation model and accepts that no FRC costs have been allocated to its transmission opex.

Staffing and productivity

EnergyAustralia notes that the high degree of competition for skills and trained staff in the NSW electricity sector has resulted in high staffing costs. To combat this, EnergyAustralia has introduced greater trainee recruitment, which has led to higher recruitment and training costs, and slightly greater employee numbers. GHD contends that these costs should be offset by lower salaries, and hence have no overall impact on opex costs.

GHD also notes that expected productivity improvements have not been identified by EnergyAustralia and future productivity improvements, for example from the introduction of RCM, will not occur in the 2004–2009 regulatory period. GHD states that there should have been productivity improvements of at least one per cent per annum and recommends adjusting the opex estimates accordingly.

In response EnergyAustralia has argued that staffing levels are increasing, in part to compensate for inadequate maintenance levels in the past. Further EnergyAustralia argues that increased recruitment of apprentices, engineers and technicians, increasing costs for existing staff, and competition for skilled staff means that productivity improvements are unlikely to occur.

The ACCC notes EnergyAustralia’s position and will not make any specific adjustment for efficiency gains from staffing.

Maintenance regime

EnergyAustralia have stressed the importance of the change in its maintenance regime to RCM, and the likely impact of RCM in future regulatory periods. GHD notes that such expenditure should be considered efficient, given the expected long term benefits from comprehensive implementation of asset lifecycle costing and asset management practices.

The ACCC considers that the change to RCM should represent an improvement over previous asset management practices.

General opex efficiency

GHD believes that an efficient business should have readily been able to achieve opex efficiency gains over the 1999–2004 regulatory period. However, GHD did not find any evidence that such gains were pursued or achieved by EnergyAustralia. GHD recommends that a reduction be applied to EnergyAustralia's opex, increasing by 0.5 per cent each year from 0.5 per cent in 1999–00 to 2.5 per cent in 2003–04.

However, EnergyAustralia notes that the organisation has achieved efficiency gains in the area of corporate overheads and future efficiency gains are expected from the implementation of RCM. EnergyAustralia states that applying a general efficiency factor would double count efficiencies already taken into account in EnergyAustralia's opex forecasts.

The ACCC notes EnergyAustralia's comments and has decided not to apply a general efficiency factor to EnergyAustralia's opex incurred in the 1999–2004 regulatory period.

5.7.3 Starting point opex

As discussed in section 5.7.2, the ACCC considers a number of adjustments need to be made to EnergyAustralia's proposed opex starting point for the 2004–2009 regulatory period. These are summarised in the table 5.6.

Table 5.6 Summary of proposed opex adjustments

Cost driver ($m 2003–04)	Year	GHD recommendation	ACCC adjustment
Superannuation—abnormal	00–01	+$0.1	+$0.1
	01–02	-$2.5	-$2.5
	02–03	-$0.1	-$0.1
Olympics	99–00	range provided	-$0.2
	00–01	range provided	-$0.1
Insurance	01–02	-$0.3	-$0.0
Productivity and general opex efficiency	99–00	-0.5%, -$0.1	-$0
	00–01	-1.0%, -$0.3	-$0
	01–02	-1.5%, -$0.5	-$0
	02–03	-2.0%, -$0.6	-$0
	03–04	-2.5%, -$0.8	-$0

The impact of the above adjustments on EnergyAustralia's opex for the 1999–2004 regulatory period is summarised in table 5.7. The average of the differences between EnergyAustralia's actual opex and the ACCC adjusted opex for the 1999–2004 regulatory period is used to modify EnergyAustralia's proposed opex starting point for the 2004–2009 regulatory period.

Table 5.7 EnergyAustralia's opex adjusted for efficiencies

($m 2003–04)	99–00	00–01	01–02	02–03	03–04
EnergyAustralia's actual opex	24.4	26.7	31.1	27.9	28.8[(a)]
Adjustments:					
Superannuation		+0.1	-2.5	-0.1	
Olympics	-0.2	-0.1			
ACCC adjusted opex	**24.2**	**26.7**	**28.6**	**27.9**	**28.8**

(a) This forecast was not provided. The ACCC derived it using the 2002–03 estimate including an assumed CPI adjustment of 3.1 per cent.

5.8 Opex 2004–2009 regulatory period

This section reviews EnergyAustralia's proposed opex allowance, and the adjustments required to take into account changes in EnergyAustralia's opex allocation methodology, the RAB, and specific cost drivers for efficiencies.

EnergyAustralia's application incorporates an increase in opex for the 2004–2009 regulatory period, estimating its starting point at $24.37m, growing to $27.73m by 2008–09. This is an increase in real terms of 14 per cent over the period. However EnergyAustralia's estimates also include an amended starting point, taking into account new asset definitions and a new allocation framework. EnergyAustralia's proposed starting point represents an increase of 13 per cent when compared to the forecast opex for 2003–04.

5.8.1 Opex starting point adjustments

EnergyAustralia does not keep separate accounts for opex classified by transmission or distribution expenditure. EnergyAustralia allocates its opex expenditure between transmission and distribution in accordance with its new allocation framework.

GHD states that the new allocation framework, based on asset classes, provides a better representation of actual transmission costs when compared to EnergyAustralia's previous global allocation framework. GHD notes that in-depth analysis of transmission opex would require either a full assessment of whole of business opex or a splitting of the transmission and distribution accounts. GHD also notes the new asset definition has been accepted by the ACCC and as such needs to be incorporated into the future estimates of opex.

The ACCC agrees that EnergyAustralia's new allocation framework provides a better indication of actual transmission opex, than the previous global allocation framework. Hence, in order to assess the reasonableness of EnergyAustralia's proposed opex for 2004–2009, the ACCC requested GHD to estimate the impact of the new allocation framework and the change in RAB (transfer of assets) on EnergyAustralia's opex over the1999–2004 regulatory period.

GHD's estimates of the impact of the change in asset definition and allocation methodology on EnergyAustralia's actual opex for the 1999–2004 regulatory period, are set out in table 5.8.

Table 5.8 Percentage change in opex, actual compared to amended (new asset definition and allocation framework)

($m 2003–04)	99–00	00–01	01–02	02–03	03–04
EnergyAustralia's actual opex[b]	24.4	26.7	31.1	27.9	28.78[a]
EnergyAustralia's new opex[c]	23.0	23.8	23.0	22.3	21.58
EnergyAustralia's new opex ÷ EnergyAustralia's actual opex (%)	**94.5**	**89.2**	**73.9**	**79.9**	**74.98[a]**

(a) These forecasts were not provided and hence used a 2002/03 estimate including an assumed CPI adjustment of 3.1 per cent.

(b) Based on original definition of transmission assets and global allocation framework.

(c) Based on new definition of transmission assets and revised asset class allocation framework.

Table 5.9 ACCC's opex allowance, adjusted for past efficiencies, new asset definition and allocation framework

($m 2003–04)	99–00	00–01	01–02	02–03	03–04
ACCC adjusted opex[b]	24.2	26.7	28.6	27.9	28.8[a]
EnergyAustralia's new to actual opex proportion (%)	94.5	89.2	73.9	79.9	75.0[a]
ACCC new opex[c]	**22.8**	**23.8**	**21.2**	**22.3**	**21.6**

(a) These forecasts were not provided and hence used a 2002/03 estimate including an assumed CPI adjustment of 3.1 per cent.

(b) Based on original definition of transmission assets and global allocation framework, incorporating past efficiency gains identified by ACCC.

(c) Based on new definition of transmission assets and revised asset class allocation framework.

Table 5.9 sets out the calculation for determining an appropriate level of opex for EnergyAustralia in the 1999–2004 regulatory period, taking into account the change in RAB (transfer of assets), the new allocation methodology and the efficiency adjustments identified by the ACCC in section 5.7.

The ACCC new opex set out in table 5.9 reflects its view of an efficient opex spend by EnergyAustralia for the 1999–2004 regulatory period, based on the new asset definition and allocation framework.

The purpose of assessing the past opex spend by EnergyAustralia is to inform the ACCC about the reasonableness of both the opex starting point and path for the 2004–2009 regulatory period. This is particularly important given the change to a new opex allocation framework and additional transmission assets to be included in EnergyAustralia's RAB.

The ACCC's calculation of the new opex for the 1999–2004 regulatory period, after adjustments for the ACCC identified efficiencies, new transmission asset definition and new allocation framework implies an average shift down in EnergyAustralia's opex of $0.43m per annum for the 2004–2009 regulatory period. This reflects the ACCC's assessment of the efficient opex for transmission assets if the new asset definition and allocation framework is used.

5.8.2 Opex cost drivers

EnergyAustralia's application shows three core categories of opex: maintenance, communications and control, and other. GHD states that due to data limitations, (in particular the dual nature of EnergyAustralia's business and lack of specifically identified transmission costs) its review of proposed opex for the 2004–2009 regulatory period utilised an analysis of total network opex and its cost drivers, rather than a detailed expenditure review.

Table 5.10 EnergyAustralia's proposed opex allowance

($m 2003–04)	04–05	05–06	06–07	07–08	08–09	Total
Maintenance	13.3	14.5	15.7	16.9	18.2	78.6
Communication and control	4.2	4.1	4.1	4.0	4.0	20.3
Other	6.9	7.1	6.8	6.2	5.5	32.6
Total opex	**24.4**	**25.8**	**26.6**	**27.1**	**27.7**	**131.6**

Source: EnergyAustralia's application, attachment G

The key opex driver is the change in maintenance practices to RCM. The impact of this and other opex drivers is discussed below.

RCM

Maintenance is the largest component of EnergyAustralia's proposed opex, and it shows a real increase of over 37 per cent during the regulatory period. EnergyAustralia states that this increase is driven by the move to RCM from time based maintenance. This shift in maintenance practices has highlighted a large backlog of necessary maintenance, and hence EnergyAustralia claims the increased opex in the short term will drive substantial long term opex efficiencies.

GHD supports EnergyAustralia's change to RCM and does not recommend any adjustment to proposed opex in respect of this driver. The ACCC considers the change to RCM should lead to an improvement in EnergyAustralia's asset management. The ACCC will not make any adjustment to EnergyAustralia's opex proposal for RCM.

Information Technology

EnergyAustralia has forecast large information technology (IT) expenditure aimed at risk management and compliance. GHD states that EnergyAustralia should include a focus on potential efficiencies in its IT development, with expected efficiencies coming from ongoing consolidation of existing systems. GHD suggests that a reasonable level of saving would be within the range of 1-5 per cent per annum, given a one year lag.

However, EnergyAustralia notes that it needs new systems to be able to ensure ongoing compliance with its regulatory, safety and financial obligations. EnergyAustralia does not believe that efficiency savings are achievable within its IT spending without potentially compromising its ability to meet its obligations. EnergyAustralia also contends that the maintenance of improved reporting (IT) systems will not lead to cost savings, although it will give EnergyAustralia a better understanding of its network. EnergyAustralia claims that GHD has not substantiated the savings estimate.

The ACCC accepts that GHD's IT savings estimate is not underpinned by detailed quantitative analysis of EnergyAustralia's IT proposals, but does not accept EnergyAustralia's claim that no potential savings can be made from its forecast IT expenditure of $33m per annum.[96] GHD suggests that savings can come in the form of system consolidation and the selection of the best systems for their needs. EnergyAustralia states that much of the IT opex will be required in the form of new IT licences, as well as IT maintenance and support services.

However, the ACCC considers that within the IT budget of $33m per annum there must exist some potential efficiency as much of the IT support and maintenance services, as well as the licensing arrangements, are contestable services. Practices such as competitive tendering and outsourcing can lead to savings.[97] While EnergyAustralia strongly contends that no IT opex savings can be made, it has not provided any evidence that its forecast IT opex represents the most efficient expenditure. For example, EnergyAustralia has not produced any analysis or business case on how these IT requirements will be sourced or the anticipated savings to the business.

Without any information to show that EnergyAustralia has adopted a competitive tendering process to source its IT requirements, the ACCC considers that EnergyAustralia should be explicitly targeting IT opex, where potential savings can be made. Hence the ACCC will adjust EnergyAustralia's opex by 3 per cent in each year of the 2004–2009 regulatory period from 2005–06, as an efficiency driver in this area. The ACCC has selected three per cent as the mid point of the potential efficiency gains identified by GHD.

Insurance

EnergyAustralia's application highlights the impact of global events on insurance costs, and GHD agrees that insurance costs will be largely driven by factors outside EnergyAustralia's control. Given the current global environment the ACCC has decided not to make any adjustment to EnergyAustralia's proposed insurance expenditure.

96 $33m per annum is the combined figure for both the transmission and distribution networks.

97 Recently, utilities (Integral Energy, ElectraNet) have announced successful tender deals for the provision of IT services. See *The Australian Financial Review*, 19 October 2004 and 9 November 2004.

Self insurance

EnergyAustralia is proposing an allowance for self insured risks of $0.44m per annum for identified events, based on an actuarial assessment by Trowbridge Deloitte. The self insured risks identified are:

- property related risks ($414,000)
- currently insured risks ($20,000)
- credit risks ($8,000).

Principles

Section 6.5 of the SRP sets out the matters, in light of the relevant code requirements, which the ACCC considers should generally be established prior to acceptance of a self insurance application. These matters are:

- a board resolution to self insure (i.e. a copy of the signed minutes recording resolution made by the board)
- confirmation that the TNSP is in a position to undertake self insurance for those events
- self insurance details setting out the specific risks which the TNSP has resolved to self insure
- a report from an appropriately qualified actuary or risk specialist verifying the calculation of risks and corresponding insurance premiums
- ensuring that the cost of self insurance is recorded as an operating expense in the audited and published income statement, and thereby deducted from the calculation of attributable profits
- ensuring that a self insurance reserve (funded by self insurance premiums charged in the income statement) is established in the audited and published balance sheet
- ensuring that when a claim against self insurance is made, that an appropriate deduction to the self insurance reserve is recorded.

The reasons for these requirements are discussed in section 6.6 of the draft SRP Background Paper[98] and section 6.6.1 of the SRP background paper.[99] In section 1.4 of the draft SRP Background Paper the ACCC states that the draft SRP would be relevant to the ACCC's consideration of revenue cap applications submitted prior to, but not finalised by, the release of the draft SRP (being the revenue cap applications submitted by EnergyAustralia and TransGrid). This was because the draft SRP provided a better guide to the ACCC's thinking than the DRP.

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98 op. cit., p. 121– 22.

99 op. cit. p. 69– 70.

EnergyAustralia's application

In the draft decision, the ACCC proposed to accept EnergyAustralia's self insurance application subject to two matters.

First, the ACCC considered that the proposed allowance of $20,000 per annum for currently insured risks held by EnergyAustralia would be included in the pass through mechanism and thus should not be included in the self insurance allowance.

In its submission of 7 July 2004, EnergyAustralia confirmed that it is liable to pay the first $10m of each claim made under its bushfire insurance policy. The $20,000 is the self insurance premium to cover this deductible. As the definition of 'Insurance Event' in the pass through rules covers the situation where the insured risk eventuates and the TNSP incurs a deductible, the ACCC confirms its decision to exclude the $20,000 premium from the self insurance allowance.

Secondly, the ACCC required EnergyAustralia to provide a copy of a board resolution to self insure.

As noted in the draft SRP Background Paper and SRP Background paper, if a TNSP decides to self insure a risk this means that if the risk eventuates, the TNSP will not be able to:

- seek a pass through under the pass through rules adopted as part of the revenue cap for any loss or expenditure resulting from the event
- seek to carry forward any loss or expenditure resulting from the event and recover it in future periods.

The ACCC is concerned that TNSPs explicitly recognise the implications of a decision to self insure. Generally, this recognition should occur at board level. The risk management strategy of an entity and approaches to events that could affect the overall risk profile of the entity are usually matters for board consideration. Such matters may require parent entity/shareholder support to self insure and/or affect debt covenant requirements of lenders. Consistent with this, to date, all TNSPs that have had a self insurance allowance included in their revenue caps have made a board resolution on this issue.

However, in response to the draft decision, the Acting Managing Director of EnergyAustralia, Mr George Maltabarow, in a letter to the ACCC dated 2 March 2005, stated:

> The decision to self-insure for certain categories of risk is a decision made by EnergyAustralia's management. It is not a decision contemplated specifically by EnergyAustralia's Board.

That is, in the case of EnergyAustralia, the Managing Director, and not the Board, determines the risk management strategy including self insurance for particular risks.

Given the individual corporate governance arrangements of EnergyAustralia, the ACCC accepts that, in this particular case, the confirmation provided by

EnergyAustralia's Acting Managing Director is sufficient to establish that EnergyAustralia:

- will undertake self insurance of the specified risks
- recognises the implications discussed above of such a strategy.

Therefore the ACCC considers that it is consistent with the code requirements set out in section 5.2 to include an allowance of $0.44m per annum for self insurance as part of the opex allowance. This decision reflects the particular circumstances of EnergyAustralia and does not alter the ACCC's general approach to assessing self insurance applications outlined in the SRP.

The ACCC also notes that the discussion in section 3.5 of TransGrid's revenue cap decision, on self insurance reporting requirements may be relevant to EnergyAustralia.

Corporate and contractor costs

Expenditure savings of 3.5 per cent have been achieved in this area due to a recent restructuring at EnergyAustralia. GHD expects that further opportunities with regard to organisational consolidation would exist and estimate savings of between 0.5–1.0 per cent per annum post implementation. However, EnergyAustralia argues that likely separation of EnergyAustralia's retail business from its network business will lead to higher corporate overheads in the future. The ACCC has decided not to make any adjustment for these costs.

Enerserve and corporate procurement

EnergyAustralia finalised a detailed review of its corporate procurement strategies in 2002. The review identified many cost saving opportunities for EnergyAustralia. A particular opportunity exists within the labour resources associated with the Enerserve contract. GHD states that the associated savings are likely to be minimal. The ACCC will not make any adjustment in this area.

Customer service levels

A large increase in customer service costs is forecast by EnergyAustralia but GHD was not able to determine whether this increase was incorporated into EnergyAustralia's proposed opex.

EnergyAustralia has since clarified that 60 per cent of customer service costs are charged to the network businesses and hence are included in the estimates of transmission opex.

The ACCC will not make an adjustment to forecast opex for customer service levels.

Capitalisation policy

GHD notes that a new capitalisation policy has resulted in $2.2m of expenditure relating to new installation inspections being capitalised. However, GHD could not identify this expenditure in EnergyAustralia's proposed opex nor ascertain how it was allocated to transmission.

Further information provided by EA has clarified its capitalisation policy, confirming the capitalisation of new installation inspections and identifying the opex estimates. No adjustments will be made in respect of the capitalisation policy.

Environmental legislation

Changes in environmental legislation have also impacted on EnergyAustralia's proposed opex. EnergyAustralia claims that an extra $6m per annum in real terms is required for transmission opex in the 2004–2009 regulatory period. GHD supports EnergyAustralia's claim and the ACCC will not make any adjustment in respect of EnergyAustralia's opex proposal for environmental legislation.

Confidential project

GHD identified a project that EnergyAustralia regards as confidential and as such the project was not discussed in detail but the implications of that project are referred to in GHD's report. Resource issues were identified as a constraint to the implementation of this project. As such, an increase of $0.074m applied to transmission opex in 2004–05 is provided in support of project implementation. GHD has extrapolated the identified savings from the project and applied them to transmission opex, resulting in a recommended annual opex reduction of $1.419m per annum, starting in 2005–06.

In response to the draft decision, EnergyAustralia contends that the information it provided to GHD was only indicative, and that the program has not been implemented. EnergyAustralia also claims that GHD did not undertake any analysis to determine if efficiency savings were achievable. EnergyAustralia argues that the proposed reductions will act as a disincentive to EnergyAustralia undertaking the project, and do not take into account any implementation risks.

However, the ACCC considers that the uncertainty in savings identified by GHD with respect to this project is not sufficient reason to suggest that no savings can be achieved. Nor does the ACCC believe that a reduction in the opex allowance as a result of such savings will be a disincentive to EnergyAustralia to implement this project. Indeed the ACCC believes that the opposite is true. A reduction in EnergyAustralia's opex allowance as a result of this project, after an allowance for implementation, will provide an incentive for EnergyAustralia to achieve a potential efficiency gain that, in the ACCC's judgement, can be realised.

Further, the ACCC notes EnergyAustralia provided it with details on the confidential project. After reviewing the details, the ACCC considers that GHD's recommendation is appropriate.

Hence, the ACCC will reduce opex by $1.4m per annum from 2005–06, and increased the opex allowance by $0.1m in 2004–05 for project implementation.

Debt raising costs

As outlined in chapter 4, the ACCC will allow EnergyAustralia benchmark debt raising costs over the regulatory period. Consistent with the Transend[100] revenue cap

100 ACCC, Tasmanian Transmission Network Revenue Cap 2004-2008/09, 10 December 2003.

decision, this cost is treated as an operating expense. It is calculated by applying benchmark costs and gearing ratio to the asset base. Debt raising costs, based on a benchmark of 9 basis points per annum, averaging about $0.36m per annum (in $real 2003–04) are allowed over the 2004–2009 regulatory period.

5.8.3 Efficient opex 2004–2009 regulatory period

The code requires the ACCC to:

- take into account EnergyAustralia's revenue requirements having regard for the ACCC's reasonable judgement of the potential for efficiency gains to be realised by the EnergyAustralia (clause 6.2.4(c)(3))

- seek to achieve an environment which fosters efficient operating and maintenance practices (clause 6.2.2(e))

- seek to achieve an incentive based regulatory regime which provides an equitable allocation between users and EnergyAustralia of efficiency gains reasonably expected by the ACCC to be achievable by EnergyAustralia (clause 6.2.2(b)(1)).

In order to derive the ACCC's proposed allowance for opex in the 2004–2009 regulatory period, EnergyAustralia's proposed opex is adjusted to reflect the new starting point, and then the impact of the efficiency cost drivers identified above are taken into account. The ACCC has reduced EnergyAustralia's opex allowance as a result of several of the efficiency drivers referred to above. The ACCC considers this will foster efficient operating and maintenance practices by EnergyAustralia and will provide incentives for EnergyAustralia to achieve efficiency gains that, in the ACCC's judgement, can be realised.

The ACCC has not reduced EnergyAustralia's opex allowance with respect to every cost driver that has the potential to deliver efficiency gains (e.g. corporate and contractor costs). However, the code does not require the ACCC to do so (nor does it provide that every efficiency gain should retained by EnergyAustralia). The ACCC considers the approach it has adopted is consistent with an equitable allocation of efficiency gains between EnergyAustralia and customers.

For the purposes of calculating an appropriate starting point opex for 2004–05, the ACCC identified specific efficiency cost savings of around $0.4m per annum. The ACCC also considers that different cost drivers will impact on EnergyAustralia's opex requirement in the 2004–2009 regulatory period and has identified further inefficiencies, for which adjustments are required. These adjustments and the ACCC's proposed opex allowance are set out in table 5.11 and illustrated in figure 5.1.

The ACCC notes that in other revenue cap decisions (Transend and TransGrid revenue cap decisions), it has imposed a general efficiency factor to forecast opex allowances. In assessing EnergyAustralia's forecast opex, the ACCC has identified specific cost drivers where scope for efficiency gains can be achieved. Therefore, for this decision the ACCC considers that applying a further general efficiency factor to EnergyAustralia's opex is not required.

Opex efficiency carryover mechanism

In the draft decision, the ACCC did not propose an efficiency carryover mechanism for EnergyAustralia's opex over the 2004–2009 regulatory period and EnergyAustralia opposed an efficiency carryover mechanism in its application.

Consistent with its draft decision the ACCC has decided not to implement an opex efficiency carryover mechanism for EnergyAustralia, despite doing so for TransGrid.

The key factor in this decision is that implementing an efficiency carryover mechanism for EnergyAustralia's transmission opex would create an inconsistency between the regulation of its transmission and distribution opex. That is, IPART has not included an efficiency carryover mechanism in its 2004–2009 distribution pricing determination.

Essentially, EnergyAustralia runs its network as one business. It allocates opex to its transmission business but this allocation is arbitrary and has changed over time. Given the arbitrary nature of the allocation methodology the ACCC is concerned that implementing an efficiency carryover mechanism could lead to windfall losses or gains to EnergyAustralia.

While there is the potential for capex to switch between transmission and distribution, this is less of an issue because the majority of EnergyAustralia's capex is in discrete projects where the expenditure can be readily attributable to its transmission or distribution business.

Further, the change in allocation methodology has compromised GHD's and the ACCC's ability to analyse EnergyAustralia's opex over the 1999–2004 regulatory period and identify an appropriate starting point for the 2004–2009 regulatory period.

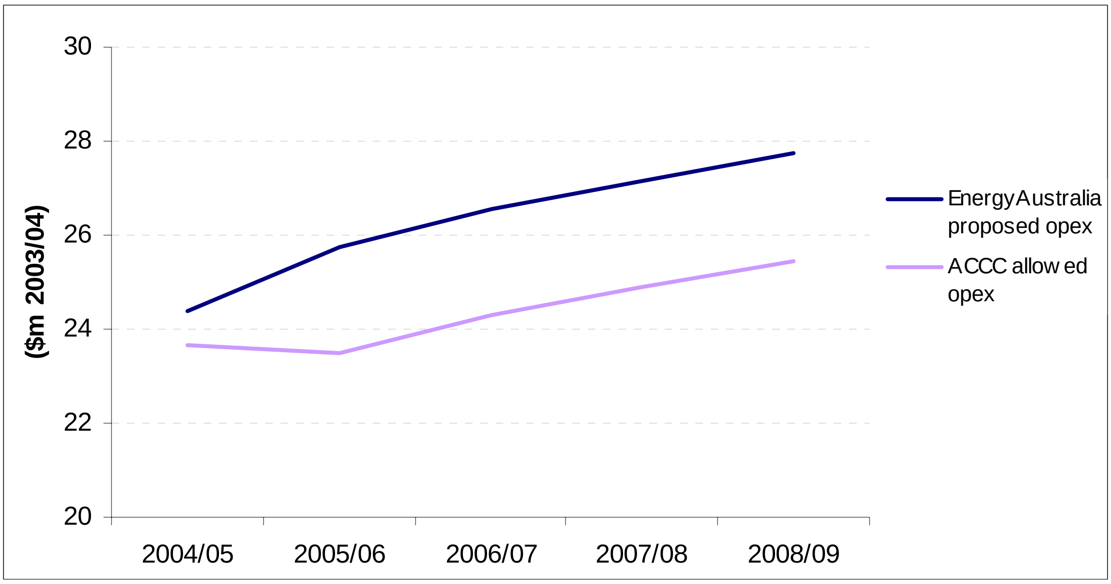
Having accurate and consistent historic information is vital when estimating an appropriate starting point. Without this information there is the risk that the estimated starting point will be too high or low and lead to windfall gains or losses to the TNSP. The ACCC considers the inclusion of an efficiency carryover mechanism could potentially amplify these windfall gains or losses in the event that there are further changes to the allocation methodology.

Table 5.11 EnergyAustralia's opex

($m 2003–04)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's proposal(a)	24.4	25.8	26.6	27.1	27.7	131.6
less: starting point variation ($0.43)	23.9	25.3	26.1	26.7	27.3	129.4
less: cost driver variation						
confidential project	0.1	(1.4)	(1.4)	(1.4)	(1.4)	(5.6)
IT	(0.7)	(0.7)	(0.7)	(0.8)	(0.8)	(3.6)
self insurance	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)	(0.02)
add debt raising cost	0.3	0.4	0.4	0.4	0.4	1.8
ACCC opex	23.7	23.5	24.3	24.9	25.5	121.9

(a) EnergyAustralia's opex forecasts do not include debt raising costs as they were included in its WACC calculations.

Figure 5.1 Opex 2004–2009 regulatory period ($m 2003–04)



5.9 Working capital

5.9.1 EnergyAustralia's application

In its application, EnergyAustralia proposed an allowance for working capital of approximately $1m per annum, as outlined in table 5.12.

Table 5.12 Proposed working capital revenue requirement

Revenue ($m nominal)	04–05	05–06	06–07	07–08	08–09	Total
Working capital	1.1	1.1	1.0	1.1	1.3	5.5

EnergyAustralia considers that at the time of the 1999–2004 revenue cap decision, the appropriateness for a return to be provided on the working capital employed in the efficient operations of a network business was not addressed. EnergyAustralia states the approach in NSW is based on the payment cycle and having regard for the average trading terms of the businesses—in effect, the amount of time that payments and receipts are outstanding.

5.9.2 Consultant's report

A paper prepared by ACG[101] for the ACCC in March 2002 describes why it is not necessary to give a service provider an allowance for working capital.

ACG believes the concern that an additional allowance in respect of working capital is required, can be interpreted as a concern that the simple formula adopted by the ACCC, when calculating the target revenue, is inappropriate. It implies the implicit assumptions in the formula about timing of cash flow in respect of operating activities may not accurately reflect the true timing of cash flow within a given year, and so understate the opportunity cost associated with investors' funds.

ACG considers that stating an additional allowance in respect of working capital is required amounts to stating, both, that:

- within year timing assumptions for the share of revenue and costs associated with operating activities, implied by the simple target revenue formula used by the ACCC, are incorrect
- the difference creates a material bias against the service provider.

ACG undertook empirical tests to assess the bias in the ACCC's target revenue formulae. The results of these tests show the post tax revenue model (PTRM) formula results in a significant bias in the favour of the service provider. The use of this formula leads to average prices of 1.8 per cent higher than required. This bias in favour of the service provider remains, even if extreme assumptions are made about the timing of expenditure within the year.

These results imply an allowance for working capital is unnecessary. While there may be a (small) financing cost associated with operating expenditure, any shortfall from not including an allowance in respect of working capital is likely to be swamped by the favourable allowance provided in respect of capital assets under the PTRM target revenue formula.

101 AGC, Working capital—relevance for the assessment of reference tariffs, March 2002

5.9.3 ACCC consideration

The ACCC's draft decision was to disallow an additional allowance for working capital. The ACCC considers ACG has addressed all concerns relating to the need for an additional allowance for working capital. Therefore, given no new issues have been raised, the ACCC has not allowed an additional allowance for working capital in this decision.

5.10 Benchmarking

The ACCC has not yet established comparative benchmarks of TNSP opex performance other than the compilation and publication of a range of partial measures (ratios) based on the regulatory account information. The ACCC consider that the establishment of robust benchmarks for Australian TNSPs would be helpful in informing decisions on opex allowances, and therefore the ACCC intends to progress the development of such benchmarks.

In page 67 of the SRP Background Paper, the ACCC noted that there is merit in the development of comparative benchmarks, since it would allow the ACCC to establish expenditure allowances without necessarily having to conduct exhaustive, firm specific cost analyses. However, considerable work would need to be done to establish reliable benchmarks that produce fair and balanced comparisons between TNSPs. The ACCC stated that it intended to begin work on appropriately calibrated benchmarks. However, as such benchmarks have not been established, the ACCC has not sought to rely on benchmarking except to the limited extent referred to in this chapter (e.g. debt raising costs).

5.11 Conclusion

The ACCC is proposing an opex allowance of approximately $122m for EnergyAustralia over the 2004–2009 regulatory period. As set out above, it considers that an average annual opex figure of around $24m (in $real 2003–2004) is appropriate for EnergyAustralia.

Table 5.13 EnergyAustralia's opex

($m 2003–04)	04–05	05–06	06–07	07–08	08–09	Total
EnergyAustralia's proposal[(a)]	24.4	25.8	26.6	27.1	27.7	131.6
ACCC proposed opex[(b)]	**23.7**	**23.5**	**24.3**	**24.9**	**25.5**	**121.9**

(a) EnergyAustralia's opex forecasts do not include debt raising costs as they were included in its WACC calculations.

(b) ACCC proposed opex includes debt raising costs.

6 Pass through rules

6.1 Introduction

Pass through rules allow a TNSP's revenue to be adjusted for expenditure by the TNSP during the regulatory period when a specified risk eventuates.

The issue of risk management is discussed in chapter 6 of the draft SRP Background Paper (18 August 2004). In summary, asymmetric specific risks could potentially be compensated for by:

- external insurance (with the cost of the insurance policy included in the opex allowance)
- self insurance (with a notional insurance premium included in the opex allowance)
- pass through rules (which form part of the revenue cap)
- reopening the revenue cap (where permitted by the code).

Under a pass through mechanism, if the specified risk (the pass through event) occurs, the MAR is adjusted for the resulting impact on the TNSP's expenditure (opex or capex). As the costs of the event are passed through, the mechanism transfers risk from the TNSP to users.

This chapter sets out:

- the code requirements
- EnergyAustralia's pass through application and subsequent events
- the ACCC's considerations and decision.

6.2 Code requirements

Clauses 6.2.2–6.2.4 of the code set out the provisions relevant to the ACCC's assessment of pass through applications. In particular:

- clause 6.2.4(a) provides that economic regulation is to be of the CPI minus X form (or some incentive-based variant). The ACCC is required to make a judgment as to the potential for efficiency gains (6.2.4(c)(3)) and to have regard to the need to provide the TNSP with incentives to increase efficiency (6.2.3(d)(1)) (see also 6.2.2(b) and 6.2.2(d)–(f))
- however, the ACCC is also required to take into account the revenue requirements of the TNSP having regard to the provision of a return on efficient investment and operating expenditure (6.2.4(c)(5), 6.2.3(d)(4) and 6.2.2(b)(2)), service standards (6.2.4(c)(2) and 6.2.4(c)(3)), taxes (6.2.4(c)(6)), network support service payments

to generators (6.2.4(c)(7)) and the on-going commercial viability of the transmission industry (6.2.4(c)(8))

- in addition, the ACCC must have regard to the need to provide certainty and consistency in regulatory processes, balance the interests of users and TNSPs and minimise the costs of regulation (6.2.3(d), 6.2.2(a) and 6.2.2(i)–(k)).

The application of the code provisions in the context of pass through mechanisms is discussed in section 6.6.

6.3 EnergyAustralia's application

In attachment 13 of its revenue cap application (23 September 2003), EnergyAustralia proposed that a pass through mechanism would operate for five categories of events:

- change in taxes event
- external event
- fees event
- insurance event
- regulatory event.

6.4 Draft decision

In the draft decision for EnergyAustralia (section 7.7 and appendix A), the ACCC proposed to approve the following events:

- change in taxes event
- service standards event
- terrorism event
- insurance event.

6.5 Submissions in response to draft decision

In response to the draft decision, the ACCC received submissions from EnergyAustralia (7 July 2004), the customers' group (20 July 2004) and ElectraNet (18 June 2004).

EnergyAustralia's submission raised the following issues:

- relevant factors

- insurance event—copies of insurance policies and interaction with self insurance
- changes in taxes event—should cover events that occur after 1 July 2004 and prior to the date of decision
- external event—revised definition
- fees event.

The customers' group raised the following issues:

- the definition of 'terrorist events' including whether a terrorist incident not directed at the TNSP's assets but potentially impacting on the TNSP's costs would be allowed
- the asymmetry of information and process where an event has occurred that would occasion a pass through of reduced costs
- whether such costs should be fully passed on to consumers.

ElectraNet raised a point concerning the operation of self insurance and the pass through arrangements, and commented that there should be a pass through of costs available once those costs exceed the allowance granted for self insurance purposes.

6.6 Draft SRP and standard pass through rules

The revenue cap process for EnergyAustralia (and TransGrid) was conducted concurrently with the ACCC's review of its DRP. On 18 August 2004, the ACCC released its proposed revised statement of regulatory principles (the draft SRP). Chapter 6 of the Background Paper to the draft SRP discussed the ACCC's approach to the use of pass through mechanisms as a means of addressing asymmetric specific risks.

In relation to pass through applications, the ACCC considered that, in light of the code requirements, a pass through event should, in general, have the following characteristics:

- it should be identified in advance with its scope precisely defined
- it should be beyond the control of the TNSP
- its financial impact should be better borne by parties other than the TNSP
- it should affect the TNSP, but not the market generally
- it should not already be compensated for in the forecast opex or other revenue cap costs
- it should not be more efficient for the TNSP to insure against the risk

- its financial impact should be material.

The draft SRP (section 6.7) also set out features that the ACCC considered should generally be included in the pass through rules.

Section 1.4 of the draft SRP Background Paper noted that, as the draft SRP provided a better guide to the ACCC's thinking than the DRP, the draft SRP would be relevant to the ACCC's consideration of revenue cap applications submitted prior to, but not finalised by, the release of the draft SRP (being the revenue cap applications submitted by EnergyAustralia and TransGrid).

Section 6.6 of the draft SRP also noted that, to assist TNSPs, the ACCC had developed a standardised set of pass through rules. These draft rules were developed to facilitate a consistent approach across revenue caps and to provide greater certainty for TNSPs and other parties. A copy of the draft rules was provided to EnergyAustralia (amongst others) for comment on 17 August 2004.

In summary, the approach set out in the draft SRP was considered to be consistent with the code provisions as:

- although the code creates an incentive based regime, certain events do not necessarily lend themselves to incentive regulation. Pass through rules provide a mechanism for dealing with events that are beyond the control of the TNSP where the costs cannot be built into a TNSP's expenditure forecasts but may have a significant financial impact on the TNSP. Limiting pass through events to exogenous, unpredictable events (and adjusting the pass through amount if the TNSP acts inconsistently with good electricity industry practice) balances the revenue requirements (and commercial viability) of the TNSP against the requirement to administer an incentive-based regime, the need to provide efficiency incentives and the interests of other parties

- precisely defining the scope of the pass through events and adopting a standard approach (where appropriate) promotes certainty and transparency. Setting a materiality threshold reduces the administrative cost of regulation.

6.7 Response to draft SRP and standard pass through rules

In response to the draft SRP, the ACCC received submissions from SPI PowerNet, TransGrid, the Energy Users' Association of Australia, EnergyAustralia, ESIPC, Powerlink, Ergon Energy, VENCorp, ElectraNet and TransEnd. The submissions are summarised in section 7.5 of the Background Paper to the SRP (8 December 2004).

In addition, EnergyAustralia (29 October 2004) and TransGrid (9 September 2004) provided specific comments with respect to the standard pass through rules, and a joint (confidential) legal advice (25 January 2005). These submissions are discussed in section 6.10.

6.8 Final SRP

In chapter 7 of the background paper to the SRP, the ACCC brought together the pass through arrangements that had previously been discussed separately in the opex and capex sections of the draft SRP.

The ACCC recognised the limitations of including pass through rules as part of a revenue cap. In particular:

- the difficulty of distinguishing between endogenous and exogenous costs
- the difficulty in defining the exogenous events with sufficient precision for the purpose of the pass through rules
- the difficulty in calculating the extent to which risks have been compensated in the decision of allowed expenditure and returns which could result in consumers paying the same cost twice
- the legal limitations in the drafting of pass through rules which form part of the final decision setting a revenue cap.

Consequently, the SRP set out the ACCC's preference not to include pass through rules in a revenue cap but to instead amend the code to allow revenue caps to be reopened within a regulatory period.

At present the revenue cap can only be reopened in very limited circumstances (see clause 6.2.4(d) of the code). In section 7.2 of the SRP, the ACCC considered that the code should be amended to allow the revenue cap to be reopened subject to the following conditions:

- the TNSP being materially adversely affected by the event
- the event being beyond the TNSP's control
- the event not having been contemplated at the time the revenue cap decision was made
- the benefits of revoking the revenue cap outweighing the detriment to the TNSP's customers from revoking the cap.

In a letter dated 22 November 2004, the ACCC advised EnergyAustralia of the ACCC's preference to replace the proposed opex pass through arrangements set out in the draft decision on EnergyAustralia's revenue cap with a revenue cap reopener. In response, EnergyAustralia indicated its preference for pass throughs.

6.9 Subsequent to SRP

Although the ACCC's preference remains to replace pass through rules with a revenue cap reopener, the code amendment is not in place at the time of this revenue cap decision.

Accordingly, in an email dated 6 April 2005, the ACCC advised EnergyAustralia that, in the absence of a code amendment, the ACCC proposed that pass through rules would be included in EnergyAustralia's revenue cap.

In response to the email, EnergyAustralia confirmed its submission of 29 October 2004 on the standard pass through rules.

6.10 ACCC's considerations

6.10.1 Inclusion of pass through rules

The ACCC affirms its preference, as set out in chapter 7 of the SRP Background Paper, to manage the uncertainty of unforeseeable events using a revenue cap reopener. However, as the code has not been amended at this time, the options available to the ACCC are to:

- include pass through rules in EnergyAustralia's revenue cap 2004–2009; or
- flag a NPV neutral adjustment at the next revenue cap re-set.

Due to the late stage of the current process, the ACCC believes that the latter approach would be inappropriate. Therefore, the ACCC has included pass through rules in EnergyAustralia's revenue cap. This decision reflects the particular circumstances of EnergyAustralia and does not alter the ACCC's general approach outlined in the SRP.

6.10.2 Form of pass through rules

The pass through rules that form part of EnergyAustralia's revenue cap are set out in appendix E to this decision. The rules are based on the standard pass through rules referred to in the draft SRP but have been revised in light of the submissions referred to in sections 6.5 and 6.7 above. The changes made are discussed below (other than the changes in response to TransGrid's submissions of 9 September 2004 and 2 July 2004 which are discussed in chapter 4 of the revenue cap decision for TransGrid).

6.10.3 EnergyAustralia submission (29 October 2004)

As suggested by EnergyAustralia:

- the requirement to notify the ACCC within one month of the TNSP becoming aware of a negative pass through has been amended to three months
- the definition of Service Standards Event has been amended to delete the reference to 'substantial' in par. (a)(iii).

In response to the other comments:

- The Network (Grid) Support Event has been retained as it is included in TransGrid's revenue cap and it is not certain that the event has no relevance to EnergyAustralia.

- The definition of Insurance Event is limited to premiums provided for in the revenue cap. The event is intended to deal with the situation where the ACCC accepts that the cost of the external insurance policy should be included in the opex allowance but there is no certainty as to what the premium will be in the future.

- The requirement to provide copies of insurance policies was included in previous pass through rules (for example, SPI PowerNet (11 December 2002) and TransEnd (10 December 2003)) and has been retained due to concerns about the asymmetry of information where a pass through event results in a reduction of costs.

- With respect to clause 2.4(b)(ii), a TNSP could potentially reduce the savings that would otherwise arise from the pass through event.

- Questions as to materiality; verification of whether a TNSP has aggravated an event; the type of information required to determine whether the event is already compensated for in the revenue cap; and the treatment of commercially sensitive information will need to be considered in the context of individual pass through applications. In relation to materiality, the ACCC notes that other regulators have applied a materiality threshold of 1 per cent of average annual smoothed revenue.[102]

6.10.4 EnergyAustralia submission (7 July 2004)

The following discussion responds to EnergyAustralia's submission on the draft decision although the ACCC notes that this was superseded by the circulation of the draft standard rules and EnergyAustralia's submission of 29 October 2004.

- External event
  - As discussed in section 6.6 above, a pass through event should be identified in advance with its scope precisely defined. The ACCC considers that the definition of an external event remains ambiguous and broad in scope and does not address the concerns set out in the draft decision with respect to this event.

- Fees event
  - The issue of fees is addressed in the definition of 'Relevant Tax'.

- Changes in taxes event
  - The rules cover a change in taxes that occur prior to the date of decision.

- Insurance event

102 For example Queensland Competition Authority, *Draft Determination: Regulation of Electricity Distribution,* December 2004, p. 45.

The timing for provision of insurance policies has been changed to be consistent with TNSPs' annual reporting requirements.

The current definition covers the situation where the insured risk eventuates and the TNSP incurs a deductible. For example, if an event occurs that comes within EnergyAustralia's bushfire insurance but the cost is equal or less than the $10m deductible, this cost can be recovered under the pass through rules (provided that the insurance provider confirms that the event comes within the scope of the insurance policy and the other requirements of the rules are satisfied).

- Relevant factors

These comments have been superseded by the draft standard rules.

6.10.5 Customers' group submission (20 July 2004)

In response to the customers' group submission of 20 July 2004:

- Terrorism event
  - The definition of 'Terrorism event' and the restrictions on what can constitute a pass through amount are intended to limit pass throughs to costs directly arising from particular terrorist incidents as opposed to indirect costs (such an increase in the price of oil) that may arise from incidents that do not directly affect the TNSP (such as a terrorist attack in another country).
- Asymmetry of information and process
  - The ACCC agrees that there is an asymmetry of information between the TNSP and the ACCC and other parties with respect to pass through events that result in a reduction of costs. The information requirements in relation to insurance policies are intended to partially address this.
- Costs passed through
  - Under the rules, the pass through amount must be adjusted by the extent to which the TNSP failed to act consistently with 'good electricity industry practice' (which is defined in the code).

6.10.6 Decision

After taking into account the code requirements, the revenue cap set by the ACCC for EnergyAustralia for the period 2004–2009 includes the pass through rules set out at appendix E to this final decision. In summary, pass throughs have been approved for:

- a change in taxes event
- an insurance event
- a network (grid) support event

- a service standards event
- a terrorism event.

7 Service standards

7.1 Introduction

The objective of this chapter is to explain the ACCC's calculation of EnergyAustralia's service standards for the 2004–2009 regulatory period.

The ACCC reviews TNSP service standards because of the incentives revenue caps impose on TNSPs. Under a revenue cap regime, TNSPs are unable to increase their revenues above the MAR and the only way TNSPs can increase their profits (on regulated activities) is by reducing their costs. Such cost reductions could result in a decline in service quality, rather than gains through efficiency, which can impose costs on other market participants.

This chapter sets out the:

- code requirements
- EnergyAustralia's application
- consultant's findings
- issues raised on the application
- issues raised on the draft decision
- ACCC's decision.

7.2 Code requirements

Clause 6.2.4(c)(2) of the code recognises that the ACCC determines a revenue cap with regard to the type and level of services that each TNSP provides. Clause 6.2.4 states:

> In setting a separate revenue cap to be applied to each Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) in accordance with clause 6.2.4(b), the ACCC must take into account the revenue requirements of each Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) during the regulatory control period, having regard for:
>
> (1) …
>
> (2) the service standards referred to in the Code applicable to the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) and any other standards imposed on the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) by any regulatory regime administered by the ACCC or by agreement with the relevant Network Users;
>
> (3) …

In November 2003 the ACCC released its service standards guidelines.[103] These guidelines set out a performance incentive scheme that aims to reduce the financial benefits potentially gained by TNSPs that achieve cost reductions at the expense of other market participants. The scheme is based on five performance indicators. Generally, the average performance during the previous three to five years becomes the performance benchmark or target in setting a financial incentive for service standards.

TNSPs are rewarded for improvements in service standards above the performance target, and penalised for deteriorations. The maximum reward or penalty is currently set at one per cent of the AR.

The ACCC's service standards guidelines are based on a consultancy report produced by SKM in 2003.[104] Both documents can be found on the ACCC's website. SKM identified two measures as being applicable to EnergyAustralia – transmission circuit availability and average outage duration. SKM recommended a target of 95.5 per cent for EnergyAustralia's transmission circuit availability. This target incorporates the ± 1 per cent financial incentive. The measure of average outage duration was recommended for data collection purposes only.

The ACCC's service standards guidelines require TNSPs to report on service standard performance on a calendar year basis. This allows for any reward/penalty to be included in TNSP's price setting for the next financial year.

7.3 EnergyAustralia's application

EnergyAustralia considers, prior to the performance targets being set, an appropriate amount of data should be available upon which to base estimates of future performance.

EnergyAustralia states it supports the ACCC's proposal to link performance service standards with financial rewards and penalties. However, EnergyAustralia claims its transmission network is different to those operated by other TNSPs and many of the service standards envisaged for other TNSPs are not relevant to EnergyAustralia. It considers the use of industry benchmarks as being inappropriate for EnergyAustralia given these differences.

7.3.1 Transmission circuit availability

EnergyAustralia has only collected transmission circuit availability performance data since 2000–01 using a manual process. The data available relates to transmission feeders only and EnergyAustralia believes SKM's recommended target of 95.5 per cent was based on data for a single year (2000–01). EnergyAustralia claims future transmission circuit availability performance is expected to differ from that year. This is due to:

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103 ACCC, Statement of Principles for the Regulation of Transmission Revenues, Service Standard Guidelines—Decision, 12 November 2003.

104 SKM, Transmission Network Service Providers—Service Standards, March 2003.

- the inclusion of transformers and reactive plant, in accordance with the proposed standard definition

- the inclusion of significant lengths of new 132kV lines and other equipment, resulting from the re-classification of some assets from distribution to transmission during the 1999–2004 regulatory period.

EnergyAustralia considers the above points make the proposed target of 95.5 per cent invalid and propose at least three years data using the standard definition of availability should be collected before availability targets are established.

At the time this decision was written EnergyAustralia had submitted a further three years data (table 7.1) for its overall availability of its transmission feeders.

Table 7.1 Transmission feeder availability

	00–01	01–02	02–03	03–04
Transmission feeder availability (%)[a]	96.6	94.6	96.3	97.4
Transmission feeder availability capped at 14 days (%)[b]	N/A	94.85	97.72	98.3

(a) Previously submitted data that was used for SKM's review.

(b) Submitted as part of the service standards compliance review.

EnergyAustralia is seeking the ACCC's agreement to the provision of availability data in the current form (i.e. not including availability of transformer or reactive plant).

7.3.2 Average outage duration

EnergyAustralia believes the second performance measure, average outage duration, is not an appropriate measure and should not be adopted during the 2004–2009 regulatory period because:

- the restoration time for equipment will generally not impact on customer outcomes, due to the inherent high level of security in the design of the system

- the inherent repair times of EnergyAustralia's equipment are much more significant than for other TNSPs due to the large amount of underground cables in EnergyAustralia's system. To reduce the repair time on cables, EnergyAustralia claims it would require large capital investments which are not the objective of the present incentive mechanism.

7.4 Consultant's report

7.4.1 Basis for review

In undertaking this review, GHD evaluated the measures proposed by SKM and the available data received from EnergyAustralia against its actual performance over the

1999–2004 regulatory period. When developing its recommended set of service standards, GHD took into account items expected to impact upon the performance of EnergyAustralia against the proposed measures in the 2004–2009 regulatory period.

7.4.2 Analysis of historical data

GHD provided a comparison of the performance of EnergyAustralia against the proposed measure of transmission circuit availability; however this is limited due to the available data. Due to timing GHD had data in relation to 2000–01 to 2002–03 for feeder availability as shown in table 7.1. It did not have the 2003–04 data for feeder availability and no data was available for the average outage duration measure.

7.4.3 GHD's conclusions

GHD concluded:

- the limited data available was insufficient to set substantial, restrictive service standards
- no data was available for average outage duration measure. However GHD agree with SKM's earlier recommendation that data be collected as this was suitable to be used as a measure in the future
- a proposed incentive scheme with cap and collar is appropriate, which includes a transmission feeder availability of 96.1 per cent. This is summarised in table 7.2.

The ACCC's draft decision adopted GHD's recommended performance incentive scheme.

Table 7.2 Service standards proposed by GHD

Performance measure	Unit of measure	Revenue at risk	Collar	Target	Cap
Transmission circuit availability	%	1%	95.3	96.1	96.7
Average outage duration	Data to be measured by EnergyAustralia during 2004-2009 regulatory period				

7.5 EnergyAustralia's 2004 performance report

In the 2004–2009 regulatory period EnergyAustralia will report its service standards for the first time under the ACCC's performance incentive scheme. Since performance is reported by calendar year, on 15 February 2005 EnergyAustralia submitted its service standards report for the period 1 July 2004–31 December 2004. This report is available on the ACCC's website.

In this report EnergyAustralia sets out its performance against the transmission feeder availability measure. It also outlines an alternate set of service standards measures that it believes would be more relevant to its network and, therefore, should replace the current performance measures. The definitions of the proposed measures for the purpose of this decision are contained in appendix D.

The ACCC engaged SKM to review EnergyAustralia's compliance with the service standards incentives for the 2004, which were set out in the ACCC's draft decision. SKM's report can be found on the ACCC's website.

SKM concluded:

- EnergyAustralia's system to record outages is largely manual, and thus subject to human error
- an automated recording system would ensure reliability of the data and compliance with the requirements of the ACCC's service standards guidelines.

SKM reported that EnergyAustralia is reviewing its recording process. EnergyAustralia stated that a new distributed network management system (DNMS) is expected to be commissioned in about two years. This new DNMS can possibly assist automate the reporting of the availability measures.

SKM also revised the advice it gave to the ACCC in 2003 in relation to EnergyAustralia, in light of the new and more consistent performance data. SKM states that the collar and cap values for total circuit availability (95.3% and 96.7% respectively) outlined in the ACCC's draft decision are too close to the present target for performance (96.1%). SKM claimed that this may result in minor events significantly impacting performance outcomes inhibiting the construction of accurate historic trends within the performance incentive scheme for EnergyAustralia. Instead SKM suggested a cap and collar of 2.5% above or below the performance target.

SKM also recommended the application of a 14 day cap to extended outage events for the calculation of total circuit availability. SKM believes this would be consistent with the calculation of performance for other TNSPs.

7.6 Submissions

EnergyAustralia, the customers' group and the EMRF made submissions in relation to the draft decision.

7.6.1 Setting the incentive

The customers' group welcomes the ACCC's decision to adopt GHD's recommended targets for EnergyAustralia. However it considers one per cent of revenue at risk does not provide a strong enough incentive for EnergyAustralia. It considers a more substantial risk/reward arrangement as being necessary.

The EMRF also considers that the ACCC should set a higher target for EnergyAustralia. It notes that this is because the target level for availability has already been met. It considers the need to increase the target is supported by comparing EnergyAustralia's performance levels to TransGrid's.

EnergyAustralia, states it would be appropriate to consider the 2003–04 availability data when setting the performance target. The draft decision was based on the three previous year's data, which EnergyAustralia considered was not appropriate to set performance targets.

ACCC's considerations

Based upon the submissions, the ACCC considers that the level of revenue at risk of one per cent is justified. This is due to the newness of the performance incentive scheme and that this is the first time that the scheme is being applied to EnergyAustralia. Increasing the revenue at risk would exacerbate any unexpected or perverse incentives that may be provided by the scheme.

The ACCC also considers the current level as providing significant incentive for TNSPs to maintain and improve service standards, as outlined in the service standards guidelines. The ACCC's experience of applying an incentive of one per cent of revenue to other TNSPs has successfully increased TNSP awareness of and focus on improving service levels.

Performance data for 2003–04 has now been provided, which is substantially higher than for previous years. Therefore, the ACCC considers there is a case for increasing the availability target from 96.1 per cent. In increasing this target, the ACCC took into consideration that EnergyAustralia's historic data is not capped to minimise the impact of an availability event. As discussed in section 7.6.5, the ACCC has capped EnergyAustralia's availability events at 14 days, resulting in a revised target of 96.96 per cent.

However the ACCC considers there is a case for increasing the availability target from 96.1 per cent to 96.2 per cent. In the draft decision the ACCC based its target of 96.1 per cent on GHD's recommendation. In coming to this recommendation, GHD reviewed actual performance data from 2000–01 to 2002–03 and recommended adoption of a target (96.1 per cent) that was higher than the average over those years.

Performance data for 2003–04 has now been provided, which is substantially higher than for previous years. The ACCC has stated the average historical performance for the past three to five years would be the basis for setting performance targets in the future. While the target recommended by GHD, which was applied in the draft decision, was higher than the average of historical performance available to it at the time it made the recommendation, the ACCC has used the historical average of the last four years. The ACCC considers the average of historical availability for the four years of data that is now available is appropriate.

The EMRF compared EnergyAustralia's and TransGrid's performance levels and concludes there is a case for an increased target for EnergyAustralia, to bring it closer to TransGrid's performance level. However, the ACCC's service standards guidelines were developed to provide a framework in which each TNSP would be given incentives to improve upon its past performance. As a result the ACCC does not believe that it would be appropriate to base the target standards for EnergyAustralia on that of another

TNSP. Therefore this has not contributed to the ACCC's decision to increase the availability target.

Further consideration of the appropriate target is given in section 7.6.2 below.

7.6.2 The impact of severe events

In its application, EnergyAustralia requests the impact of a single event be capped at seven days. It is concerned that the ACCC did not recognise its request and would like the ACCC to reconsider its decision and reduce the cap for events to seven days.

ACCC's considerations

The service standards guidelines do not specifically include provisions to cap certain events, however TNSPs have historically recorded performance to meet their own internal reporting requirements, and some have capped events at seven or 14 days for their own purposes. These internal measures have not been consistent across TNSPs.

In recommending the standard measures for the performance incentive scheme SKM recognised these inconsistencies. Appendix B of the service standards guidelines includes a table showing where each TNSP's historical measures vary from the standard measures recommended by SKM.

The need to cap the impact of events is particularly relevant to EnergyAustralia where it has many underground feeders running through the Sydney CBD. That is, an outage event occurring on an underground cable is likely to require more time to restore than a similar event on overhead lines.

If large events had been capped in EnergyAustralia's actual historical availability, shown in table 7.1, the ACCC considers that the historical performance would have been greater. Therefore increasing the performance target would be appropriate.

The effect of capping events at 14 days resulted in feeder availability 96.96 per cent over 2001–02 to 2003–04. The ACCC considers this is a good estimate of what performance should be if events were capped at 14 days.

Therefore the ACCC considers 96.96 per cent availability is an appropriate target for capped transmission circuit feeder availability.

7.6.3 Impact on expenditure

EnergyAustralia believes lower service quality will result from the ACCC's revenue cap decision. EnergyAustralia claims that since the draft decision proposed a level of future expenditure that was less than the amount it had proposed in its application that a lower service outcome will result which should be reflected in the performance target. EnergyAustralia states that it does not believe it is reasonable to expect service levels to be maintained with reduced expenditure.

ACCC's considerations

While the ACCC considers that a positive relationship should exist between expenditure and performance of TNSPs, all else being equal, the relationship between expenditure and the performance of the network is not as simple as EnergyAustralia's argument would suggest.

In considering EnergyAustralia's argument the ACCC notes that both the draft decisions, and this decision, provide EnergyAustralia with a level of expenditure which is higher than EnergyAustralia has undertaken in the past. Thus, if EnergyAustralia's argument is accepted, it should be providing a higher level of performance. For example the revenue stream set in this decision is based on a total capital expenditure of $207m ($2003–04) compared with actual capex of $135m ($2003–04) over the past five years. However, the ACCC does not concede that the relationship between expenditure and the performance of the network is that simple. Hence, the ACCC has not determined the performance target on the basis of the expenditure, or vice versa.

In setting an appropriate revenue cap the ACCC has determined what it considers to be an appropriate amount of expenditure by examining the application EnergyAustralia put forward. For both opex and capex, the ACCC's decision was assisted by independent consultants, who examined EnergyAustralia's capex and opex proposals.

In setting the appropriate incentive scheme the ACCC has determined what it considers to be an appropriate and achievable availability target by taking the average actual availability over the past four years.

The ACCC considers that, in this instance, there is no case to alter the level of expenditure due to the availability target and that there is no case to alter the availability target on the basis of the expenditure levels.

7.6.4 Performance measures

In its service standards report, EnergyAustralia proposes alternate measures for circuit availability. These are:

- MVA days of feeder availability
- MVA days of 'transmission bulk supply' transformers non-availability
- MVAr days of reactive plant non-availability.

EnergyAustralia also proposes two measures that would report its performance in relation to planned and forced outages:

- loss of supply due to forced transmission asset outages
- loss of supply due to planned outages.

ACCC's considerations

The ACCC considers the performance measures set out by EnergyAustralia as being a considerable step forward in improving the performance incentives that can be provided through the revenue cap. Further, the ACCC notes that section 2.2 of the service standards guidelines states it may 'consider the TNSP's request to include additional and/or amendments to performance measures when it makes its transmission revenue cap decision'.[105]

The ACCC agrees in principle that these measures should be reported for transparency purposes. However, in the absence of details in EnergyAustralia's proposal, the ACCC has made certain assumptions in including these measures within EnergyAustralia's performance incentive framework. For example, the ACCC has assumed that the definitions of exclusions and inclusions for the availability measure are the same as those in the ACCC's service standards guidelines. These relate to details which ensure the performance report is both consistent over time, and can be understood and interpreted.

These assumptions (appendix D) are consistent with the performance measures defined in the service standards guidelines.

7.6.5 New transmission assets

EnergyAustralia considers that there is merit in measuring, for the purpose of determining a financial incentive, the performance of a particular set of assets over time. That is, EnergyAustralia believes new transmission assets, in particular those that were previously classified distribution assets, should be excluded from any performance measure when a financial incentive is at stake.

ACCC's consideration's

The ACCC considers that performance measures should be aggregate levels of transmission performance. In other words, the ACCC is attempting to measure the entire output that the transmission network provides to the market.

The ACCC believes that excluding particular assets would inhibit the application of any service standard incentive from being provided for the operation of those particular assets. Further, the ACCC considers that the inclusion of more assets in the measurement of performance reduces the risk of distortion, resulting from any single asset's poor or perfect performance, upon the final performance outcome and resulting financial incentive.

7.7 Decision

For the reasons discussed above, the ACCC's decision is that for the purposes of service standards EnergyAustralia should report the performance measures defined in appendix D. All measures should be recorded and reported annually based on calendar years, in accordance with the service standards guidelines, for the purpose of improving the incentives that can be offered in the next regulatory reset.

One measure, feeder availability, should be reported for the purpose of determining an annual financial incentive.

105 op. cit., p. 1.

Table 7.3 Performance incentive target

Performance measure	Unit of measure	Revenue at risk	Collar	Target	Cap
Transmission circuit availability (capped at 14 days)	%	1%	94.46%	96.96%	98.96%
Transformer and reactor availability	Data to be measured by EnergyAustralia during 2004-2009 regulatory period				
MVA days of feeder availability	Data to be measured by EnergyAustralia during 2004-2009 regulatory period				
MVA days of 'transmission bulk supply' transformers non-availability	Data to be measured by EnergyAustralia during 2004-2009 regulatory period				
MVAr days of reactive plant non-availability.	Data to be measured by EnergyAustralia during 2004-2009 regulatory period				
loss of supply due to forced transmission asset outages	Data to be measured by EnergyAustralia during 2004-2009 regulatory period				
loss of supply due to planned outage.	Data to be measured by EnergyAustralia during 2004-2009 regulatory period				

Table 7.4 shows the equations that will be used to calculate the S-factor annually. This is based on the target, cap and collar shown in table 7.3.

Figure 7.1 Performance incentive curve

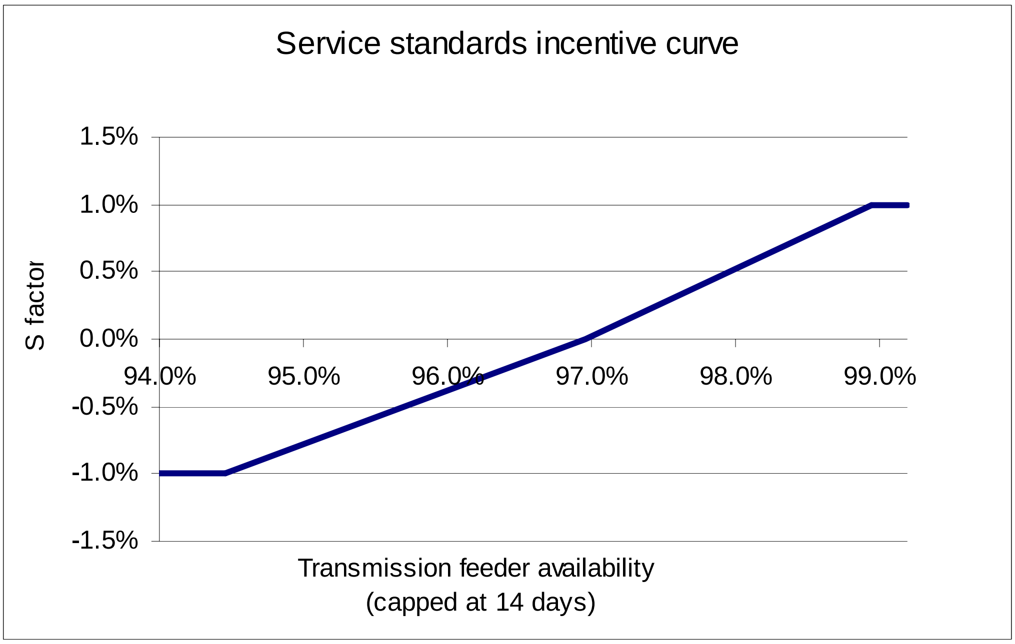


Table 7.4 Equations to calculate the S-factor

							Where:				
S	=	-0.01							Availability	<	94.46%
S	=	0.40	x	Availability	+	-0.387827	94.46%	≤	Availability	≤	96.96%
S	=	0.50	x	Availability	+	-0.484783	96.96%	≤	Availability	≤	98.96%
S	=	0.01					98.96%	<	Availability		

8 Total revenue

8.1 Introduction

This chapter explains the ACCC's calculation of EnergyAustralia's MAR from 1 July 2004 to 30 June 2009.

The ACCC's role as regulator of transmission revenues is limited to determining a TNSP's MAR. As shown below, the MAR is calculated by adding (or deducting) a financial incentive related to service standard performance and pass through amounts to (or from) the AR.

TNSPs are responsible for calculating the transmission charges payable by their customers in accordance with the principles contained in part C of chapter 6 of the code. TNSP's must notify customers of the transmission service prices that are to apply for the following financial year by 15 May each year for the purposes of determining distribution prices as outlined in part E of chapter 6 of the code.

The annual revenue that a TNSP recovers through these charges must not exceed the MAR set by the ACCC. Any over or under recoveries must be offset against a TNSP's revenues in the following year.

8.2 The accrual building block approach

The building block formula, below, is used to calculate the unsmoothed revenue for the regulatory period. The MAR is equivalent to the AR for the first year of the revenue cap:

AR = return on capital + return of capital + opex + tax

= (WACC x WDV) + D + opex + tax

where:

AR	=	annual revenue
WACC	=	post-tax nominal weighted average cost of capital
WDV	=	written down (depreciated) value of the asset base
D	=	depreciation
opex	=	operating and maintenance expenditure
tax	=	expected business income tax payable

Each subsequent year's AR is calculated as follows:

$AR_t \quad = \quad AR_{t-1} \times (1 + CPI) \times (1 - X)$

where:

AR	=	annual revenue
t	=	time period/financial year
CPI	=	actual CPI
X	=	smoothing factor

The following formula is used to calculate the MAR for each year. If a pass through is approved, the amount approved will be included in the MAR.

MAR_t = (annual revenue) ± (financial incentive) ± (pass through)

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

where:

MAR	=	maximum allowed revenue
AR	=	annual revenue
S	=	service standards factor
t	=	time period/financial year
ct	=	time period/calendar year

8.3 EnergyAustralia's application

In its application, EnergyAustralia asked for a smoothed revenue of $108m in 2004–05, increasing to $128m in 2008-09. In 2003–04, EnergyAustralia's comparable AR was $78m.

EnergyAustralia notes that the large adjustment between 2002–03 and 2003–04 is primarily the result of new assets added to the transmission asset base. These new assets result from:

- the construction of assets not envisaged at the time of the 1999–2004 revenue cap decision
- a number of assets which are now meeting the code definition of transmission assets due to system changes and therefore have moved from the distribution to transmission asset base.

EnergyAustralia states the revenue stream it is seeking over the 2004–2009 regulatory period will allow it to maintain its ageing network and undertake both new capital works and replacement of old elements of the network, thereby ensuring high quality transmission services for its customers.

EnergyAustralia states the higher revenue requirement is appropriate as it is entering a stage where higher levels of capital and operating expenditures are being undertaken.

8.4 ACCC's assessment of the building blocks

8.4.1 Opening asset base

To establish the appropriate return on capital, the ACCC modelled EnergyAustralia's asset base (over the life of the regulatory period) and WACC (estimated on the basis of the most recent market financial information).

As explained in chapter 2, the ACCC has determined the value of EnergyAustralia's asset base as at 1 July 2004 to be $635.6m.

The roll forward methodology provided an aggregate opening RAB. To accurately model EnergyAustralia's revenue allowance for the 2004–2009 regulatory period, this aggregate value should be split into the individual asset classes as proposed by EnergyAustralia in its (pro forma) application.

At the time of the draft decision the information split into its individual asset classes was not available. However this information has now been provided and the ACCC has used this information in its roll forward calculation.

8.4.2 Capital expenditure

As explained in chapter 3 the ACCC has provided a capex allowance of $207m ($2003–04).

8.4.3 Depreciation (return of capital)

The ACCC used a straight-line depreciation method (based on the remaining life per asset class of existing assets and the standard life for new assets) to model economic depreciation. The resulting figures (referred to as return of capital) are shown in table 8.1.

8.4.4 Weighted average cost of capital

The ACCC's estimate of EnergyAustralia's WACC is explained in chapter 4.

The ACCC has used a post-tax nominal return on equity of 11.98 per cent, combined with a pre-tax nominal cost of debt of 6.88 per cent, which equates to a nominal vanilla WACC of 8.92 per cent. This is multiplied by the RAB to determine the return on capital component for 2004–05 to 2008–09.

8.4.5 Operating and maintenance expenditure

As explained in chapter 5, the ACCC has included an opex allowance of about $24m per annum (in $2003–04) on average over the regulatory period.

8.4.6 Estimated taxes payable

Tax estimates relate to the network's regulated activities only. The ACCC anticipates EnergyAustralia would be paying income tax during the regulatory period, based on EnergyAustralia's tax depreciation profile. The ACCC's assessment of taxes payable are based on the 60 per cent gearing assumed in the WACC parameters as opposed to EnergyAustralia's actual gearing. The ACCC's estimates of EnergyAustralia's tax payments are as shown in table 8.1.

8.5 ACCC's decision

The ACCC proposes an unsmoothed revenue allowance that increases from $95m in 2004–05 to $119m in 2008–09, as shown in table 8.1.

The ACCC's draft decision allowed a revenue of $91.27m to be recovered in 2004–05. After taking into consideration the issues relating to RAB, capex, opex raised in response to the draft and the supplementary draft decisions the ACCC's decision is that the appropriate revenue EnergyAustralia should have recovered in 2004–05 was $95m.

This under recovery of about $4m has been smoothed, in NPV terms, across the remaining four years MAR.

Table 8.1 EnergyAustralia's unsmoothed AR

Revenue ($m nominal)	04–05	05–06	06–07	07–08	08–09
Return on capital	56.7	60.3	62.3	66.1	69.4
Return of capital	11.0	12.1	13.4	14.8	16.2
Operating expenses	24.3	24.7	26.2	27.5	28.8
Estimated taxes payable	6.3	7.4	8.0	8.6	9.5
Value of franking credits	-3.1	-3.7	-4.0	-4.3	-4.7
Unadjusted revenue allowance	95.1	100.9	105.9	112.7	119.2

The ACCC has determined a smoothed revenue allowance for EnergyAustralia that increases from $91.3m in 2003–04 to $124.3m in 2008–09, as shown in table 8.2.

The actual CPI for quarter ending 31 March 2005 is scheduled for release by the ABS on 27 April 2005. However the ACCC made this decision prior to the release of the actual CPI. Therefore this decision is based on forecast inflation rate of 2.49 per cent per annum for 2004–05 to 2008–09. The decision also applies a smoothing factor of –5.40 per cent.

Table 8.2 EnergyAustralia's smoothed AR

Revenue ($m nominal)	03–04[(a)]	04–05	05–06	06–07	07–08	08–09
Smoothed AR	78.1	91.3	98.6	106.5	115.1	124.3

(a) Final year of 1999–2004 revenue cap decision

The final MAR, each year, will be determined by adjusting the forecast AR for actual inflation and X-factor; then adding (or deducting) to the AR the service standards incentive (or penalty) and any allowed pass through amounts.

This revenue cap covers transmission services defined by the code and associated activities to be regulated by the ACCC, provided by EnergyAustralia. The ACCC considers the total revenue it has allowed will not adversely affect the financial standing of EnergyAustralia's business. Appendix C contains the ACCC's examination of EnergyAustralia's likely credit rating under the revenue cap.

The revenue increase over the regulatory period consists of an initial increase of about 16.9 per cent (nominal) in the first year, which equates to a 15.2 per cent increase in the average transmission price. This increase is mainly as a result of increases in the asset base because of:

- assets that met the code definition of distribution asset in the 1999 revenue cap, now meet the code definition of transmission asset. If these assets did not become transmission assets the first year increase in revenue would only be 8.9 per cent (nominal), which is about a 6.4 per cent average price increase

- transmission capex undertaken in the 1999–2004 regulatory period. If this capex was excluded from the RAB the first year increase in revenue would only be 12.1 per cent (nominal), which is about a 10.5 per cent average price increase.

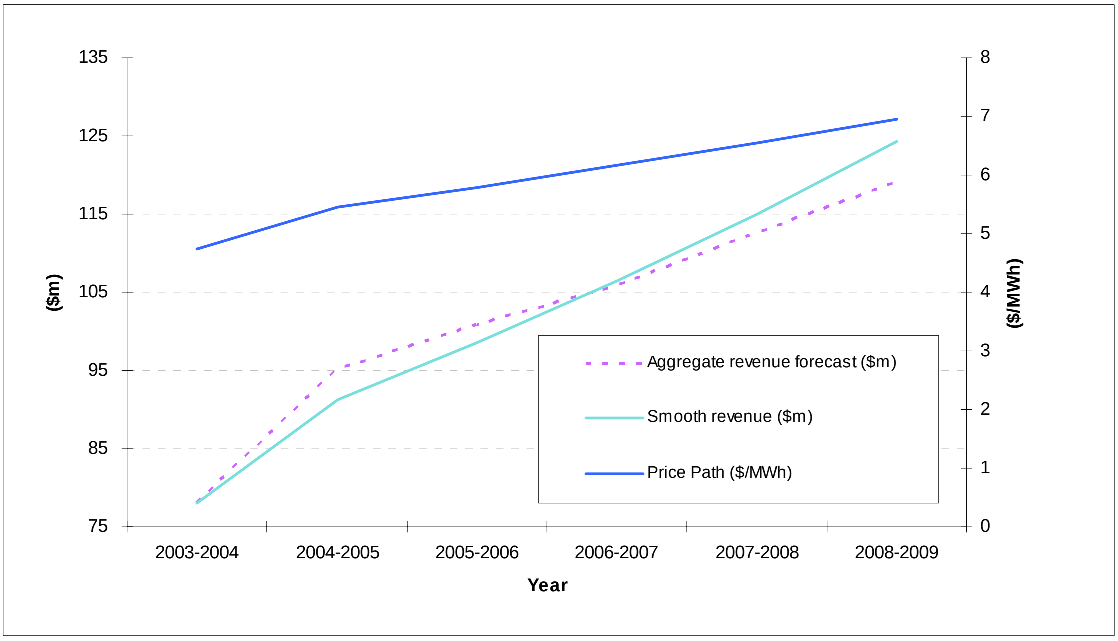
For the subsequent years of the regulatory period the revenue increases about 8.0 per cent per annum (nominal) on average, which is about a 6.3 per cent average price increase.

The ACCC estimates that its decision will result in, on average, an annual nominal 8 per cent increase in transmission charges over the regulatory period. Transmission charges represent approximately 10 per cent of end user electricity charges.

Figure 8.1 compares the revenue proposed by EnergyAustralia in its application with that allowed by this decision (both smoothed and unsmoothed).[106] It also shows the resulting price path of this decision over the regulatory period.

106 The 2003–04 revenue of $78.08m excludes the transfer of additional assets to EnergyAustralia's opening RAB for 2004–05.

Figure 8.1 Revenue comparison and illustrative price path 2003–04 to 2008–09 ($m, $/MWh nominal)



8.6 Pricing for New South Wales

EnergyAustralia has informed the ACCC that due to the nature of pricing for EnergyAustralia's transmission customers which utilises a large fixed component, the revenue received is consistent with the allowed revenue for each year of the 1999–2004 regulatory period. In NSW, TransGrid calculates transmission prices for itself and EnergyAustralia. A monthly settlement occurs between EnergyAustralia and TransGrid to ensure that each TNSP is recovering its portion of the MAR.

8.7 Discount recovery

Clause 6.5.8 of the code allows for TNSPs to recover from other customers the amount of a discount on TUOS charges (general and common service charges), subject to ACCC approval in accordance with the discount recovery guidelines.[107]

Where an application for approval of a discount recovery was made prior to publication of the discount recovery guidelines (3 May 2002) the code allows for the ACCC to approve the discount recovery at the time of the application.

107 ACCC, Statement of principles for the Regulation of Transmission revenues, Guidelines for the negotiation of discounted transmission charges, 3 May 2002.

Where applications for approval of a discount recovery have been made after 3 May 2002 the code requires that these discount recoveries are approved at each revenue reset. In these cases, the ACCC must include its assessment of the discount recovery application in its revenue decision, without breaching any confidentiality requirements.

In order to comply with the discount recovery provisions of the code, EnergyAustralia is required to include such information as is necessary to satisfy the ACCC that:

- where an application was made prior to 3 May 2002, the terms of the discount and amounts being recovered remain in accordance with any approval given
- where an application was made after 3 May 2002 there have been no substantial errors or omissions identified in the information provided at the time a discount recovery application was made.

The ACCC has confirmed that EnergyAustralia has been recovering discounts, offered to a large customer, from other customers. Details of discounts remain confidential, however the ACCC is satisfied EnergyAustralia has complied with the guidelines for recovering discounts.

8.8 Submissions

8.8.1 Price impact

The EUAA would like the ACCC to assess the impact of its decision on customer bills. The EUAA believes it is of limited use to provide only information on average impacts, when it is well known that some customers are impacted by new TUoS charges in ways that far exceed the average impact.

The EUAA urges the ACCC to consider not just transmission price impacts of its decision, but also undertake pool price studies to assess the impact of major interconnection and/or augmentation projects. It also proposes the ACCC release for public consultation the findings of these studies to allow end users to evaluate which scenario provides the best medium to long-term energy pricing and reliability outcomes.

ACCC's considerations

The ACCC considers that it is more practical to present an average price impact of its revenue cap decision rather than the impact on individual customer bills. Looking at individual price impacts would require arbitrary assumptions regarding specific characteristics and demographics of customers. These assumptions could result in large errors occurring and compromise the ACCC's ability to produce meaningful results.

The ACCC identifies that there will be end users who will be better or worse off than the average price impact. However the ACCC considers that the average price impact gives a greater representation of the population as a whole. Further, the ACCC has always used an average of the price impacts to customers and considers it to be a useful way of presenting price impacts.

Appendix A Contingent projects' triggers

This appendix lists the projects that the ACCC has, in this decision, excluded from the main ex ante capex allowance. It also sets out the triggers that should see EnergyAustralia notify the ACCC of its intention to invoke a contingent project.

A.1 Replacement of feeders 908/9

The replacement of feeders 908/9 is driven by the need to replace aged cables. In this case the ACCC considers the contingent project to be triggered and EnergyAustralia has written to the ACCC to notify it that it will begin its investigation of the most appropriate solution.

The scope of this project is to replace the function of the existing feeders 908/9 from Canterbury to Bunnerong.

This contingent project, now it has been triggered, will be subject to the assessment process outlined in appendix B.

A.2 Major inner metropolitan 132kV network development

The major inner metropolitan 132kV network development is a program to address network constraints emerging in Sydney. Table A.1 shows the network constraints of concern to EnergyAustralia that are driving this project.

Table A.1 Project drivers and triggers

Year	Network element constrained	Constraint conditions
2005	TransGrid's feeder 41.	Single contingency outage of TransGrid's feeder 42.
2008	TransGrid's feeder 42.	Single contingency outage of TransGrid's feeder 41.
2009	TransGrid's Sydney South transformers 1, 2, 4, 5 & 6.	
2010	EnergyAustralia's feeders 910 & 911.	

The ACCC considers it appropriate that this project should be triggered by EnergyAustralia providing a detailed identification of needs document highlighting these key constraints.

A.3 Customer connections

The ACCC considers that proposed connections should be triggered if all of the following criteria are met:

- one of the listed potential customers requires connection to EnergyAustralia's transmission network
- a regulatory test assessment requires shared network augmentation
- the shared network augmentation required in the regulatory period is material
- the shared network augmentation is not already allowed in other augmentation projects.

Appendix B Assessment of contingent projects

This appendix outlines the process the ACCC intends to use to assess EnergyAustralia's requests to invoke a contingent project.

Appendix A lists the contingent projects that might be invoked during the regulatory period. It also includes a set a triggers that must be satisfied for a contingent project to be invoked.

The process outlined in this appendix should be considered indicative of the process that will be followed in the future. This process and times indicated are likely to vary to account for the needs of the projects and the timing of EnergyAustralia's investment decision making process.

B.1 EnergyAustralia's application

EnergyAustralia stated that its governance procedures deliver the majority of information that is likely to be required for the approval of its contingent projects.

EnergyAustralia proposed to use the outputs of its governance framework as a starting point for the approval of its contingent projects. Its reasons for this proposal are that aligning its governance framework with the regulatory approval process for contingent projects will limit the administrative complexity and costs. It will also allow the ACCC to raise issues at the time that will allow EnergyAustralia to address concerns prior to investment decisions being made. The outcomes of EnergyAustralia's governance framework are:

- identification of needs, statement of need and network options, instruction for project options study
- instruction for project/program development
- project/program authorisation
- project/program completion and acceptance
- post implementation review.

EnergyAustralia proposed that these outputs will be forwarded to the ACCC at the time the documents are generated by the governance process. This will allow ACCC staff to be informed of new information as it becomes available to EnergyAustralia management.

B.2 ACCC's considerations

The ACCC considers it to be appropriate that where possible it should align the process to assess invoked contingent projects with EnergyAustralia's governance framework.

Table B.1 shows where the ACCC's process aligns with EnergyAustralia's governance framework.

Table B.1 Alignment of ACCC and EnergyAustralia processes

Stages of assessment	Steps in the assessment process outlined in attachment G to the SRP	Steps in EnergyAustralia's governance framework
1	TNSP invoke contingent event.	Identify issues
2	TNSP should apply the regulatory test or other investment appraisal process	Develop feasible options
3	ACCC sets an incentive for the contingent project.	Plan and justify
4		Execute project
5	Re-setting the revenue cap	Operate and evaluate

EnergyAustralia's governance framework was discussed in chapter 2 and the ACCC's SRP (attachment G) outlines the generic process to be used to assess contingent projects. The following discusses how the two processes are aligned to ensure that EnergyAustralia's contingent projects are assessed effectively.

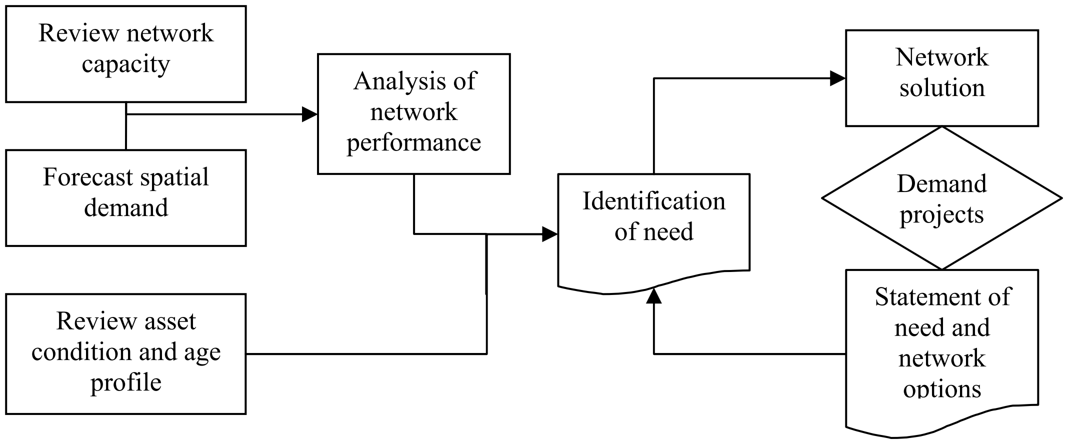
Stage 1 Invoke the contingent event

In the first instance EnergyAustralia should identify the needs or drivers of the project. Typically this will be associated with the contingent project triggers defined in appendix A. Hence the outputs provided to the ACCC should include supporting information and an explanation that shows how the contingent project has met the trigger events.

EnergyAustralia's governance framework caters for this stage (figure B.1) with its stage 'identify issues'. EnergyAustralia states that the outputs of this stage are typically:

- identification of needs
- statement of need and network options
- instruction for project options study.

Figure B.1 EnergyAustralia's governance—identify needs



The complexity of the needs and the trigger events will dictate whether the ACCC requires expert assistance in this first stage. It will also dictate what supporting information the ACCC will request to form an opinion.

Upon receiving any necessary expert advice and supporting information from EnergyAustralia the ACCC will write to EnergyAustralia stating whether it considers a contingent event has been triggered.

For information only, the ACCC will also publish on its website its letter to EnergyAustralia. It will also place on the website any other information about the identification of needs that is not commercially sensitive under the code.

Stage 2 Investment appraisal

The ACCC considers that in the past EnergyAustralia has selected the preferred option after considering a high level options analysis. To assess contingent projects the ACCC will be looking for further details. Its view is that further consideration of the options, their forecast costs, sensitivities and risks for each possible scenario will ensure the most efficient project is selected.

Therefore this stage of the process will include identifying a range of possible options to address the needs identified in stage 1 above. It will also include a regulatory test or other investment appraisal to determine the most efficient option.

In selecting the preferred solution EnergyAustralia undertakes two steps in its governance framework:

- develop feasible options
- plan and justify.

The ACCC considers it appropriate to separate this stage of the assessment into the two steps identified by EnergyAustralia.

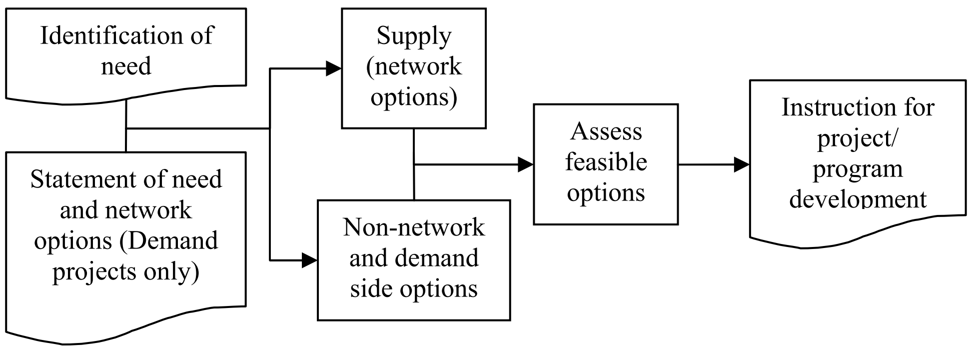
Development of feasible options

In this step (figure B.2) EnergyAustralia will develop a set of feasible options to address the need for the project. These options should include both demand management and network options and include the relevant costs involved. This step is intended to assess the options that require further detailed assessment.

EnergyAustralia's assessment of the feasible options should consider the impact of required environmental and other development approvals. Such approvals may have an impact on both timing and cost of the options. Therefore without these considerations the most efficient option can not be selected.

The output of EnergyAustralia's governance framework at this step is an instruction for project/program development.

Figure B.2 EnergyAustralia's governance - develop and justify



Plan and justify

EnergyAustralia state that this step involves a set of project offers being made against the instruction for the project/ program development. A project offer is a detailed review of an option that the instruction for development indicated required further assessment.

Project offers are assessed to determine that they still satisfy the technical needs. In addition an economic assessment is undertaken to ensure the most efficient option is selected.

The output of EnergyAustralia's governance framework at this step is:

- justification for project selection
- authorisation of selected project.

EnergyAustralia's governance framework indicates that at this step it may only consider one preferred option. The ACCC considers that at this stage it is often too late to make substantial changes to the preferred option. Therefore if only one option is considered in the plan and justify step EnergyAustralia may be forced to select an option that is inefficient.

Proceeding with an inefficient option would be a concern if the plan and justify step demonstrates that the required capex is much more than that forecast in the develop feasible options step. Without detailed assessment of the alternatives, the ACCC can not determine the most efficient option.

Public consultation process

The ACCC will undertake consultation with interested parties throughout the assessment of the contingent project. However in this stage it is likely to be more significant than the other stages. It may also include more consultation than is required by the regulatory test.

In this stage the ACCC may obtain an independent assessment of the contingent project by an appropriate expert.

The public consultation may include a call for interested parties to make written submissions prior to EnergyAustralia finalising its investment decision. Interested parties would be requested to make submissions on any expert advice received and EnergyAustralia's draft justification of project selection.

Stage 3 Setting the incentive

The ACCC will write to EnergyAustralia informing it of the value the ACCC intends to include in the RAB for the period of the incentive. EnergyAustralia would then be free to undertake the remainder of its governance framework, including a final justification of project selection.

In forming an opinion about the value to be included in the RAB the ACCC would consider:

- the issues raised by submissions
- the draft justification of project selection (and EnergyAustralia's considerations up to that point)
- expert advice.

For information only, the ACCC will also publish via its website its letter to EnergyAustralia. It would also request that EnergyAustralia's final justification of project selection report be placed on the ACCC website for information purposes only.

The incentive that the ACCC designs for each contingent project will include the following for the incentive period:

- the start date of the incentive period
- the end date of the incentive period
- the annual profile of the target capex
- the AR, which will comprise of a return of capital and return on the capex.

The revenue cap cannot be adjusted during the regulatory period as a result of the ACCC's approval of the contingent project. In the absence of a code change to permit this to occur, the ACCC's decision will be implemented at the re-set of the revenue cap in the manner discussed at stage 5 below.

Stage 4 Investment in the contingent project

This stage involves the delivery of the project where EnergyAustralia invests in the contingent project according to the capex selected in the regulatory test or other investment appraisal.

EnergyAustralia would then have the ACCC's considerations of the contingent project and would be left to complete the remaining steps of its governance framework. These two steps are to execute the project and then to operate and evaluate the project.

Stage 5 Implementation of the contingent project approval

This revenue cap is due to expire on 30 June 2009. At the re-set of the revenue cap:

- the ACCC will add to the closing RAB the target capex and AR approved at Stage 3 for each year of the incentive period leading up to the re-set
- the ACCC will add to the ex ante capex allowance the target capex and AR approved at stage 3 for each year of the incentive period that comes after the re-set.

At the revenue cap re-set, following the completion of the incentive period, the ACCC will add to the closing RAB the depreciated value of the actual investment in the project that complies with the requirements of the code. This will include the return on and return of the actual investment for the period between the end of the incentive period and the revenue cap re-set.

Timing

The ACCC would like to be able to forecast the amount of time it requires to assess the contingent project, that is, the time required from stage 1 to the completion of stage 3. However this would to a large extent depend on the timing of EnergyAustralia's decision making process.

In its typical decision making process the ACCC would suggest allowing about 4 weeks for each of the following:

- public submissions
- expert review
- ACCC consideration of all issues.

The times stated above are intended to provide an indication of the times expected for each review. Some of these events could overlap and the length of time required may change.

The ACCC expects that the assessment process for a contingent project proposal may take from two to six months, after the ACCC has confirmed that the trigger(s) for the contingent project have been met. However, this indicative time frame largely depends on the specific requirements of the project.

Appendix C Financial indicators

C.1 Code requirement

The code requires that the ACCC consider various issues when setting a revenue cap for a TNSP. One requirement when considering the TNSP's revenue requirement is 'any other financial indicators' as prescribed by clause 6.2.4(c)(9) of the code.

> 6.2.4 (c) In setting a *revenue cap* to be applied to each *Transmission network Owner* and/or *Transmission Network Service Provider* (as appropriate) in accordance with clause 6.2.4(b), the *ACCC* must take into account the revenue requirements of each *Transmission Network Owner* and/or *Transmission Network Service Provider* (as appropriate) during the *regulatory control period,* having regard for:
>
> …
>
> any other financial indicators.

C.2 Previous financial indicator analysis

In previous revenue cap decisions the ACCC has calculated and analysed various financial indicators. The purpose of this analysis was to predict the impact of the AR on the TNSP's ability to obtain credit. Consistent with the previous revenue caps, table C.1 provides the same financial indicators based on EnergyAustralia's AR.

Table C.1 assumes a business profile of above average and excellent[108], which results in a credit rating of about 'A'. Therefore the ACCC considers that its revenue cap for EnergyAustralia will not adversely affect either the ongoing financial viability or EnergyAustralia's ability to access capital markets.

The estimated credit ratings are set on the basis of the Standard's and Poor's ratings shown in table C.2. The individual financial ratios have been calculated using the formulae in table C.3.

C.3 Purpose

The ACCC has included financial indicator analysis as a check to verify the reasonableness of the revenue cap. The analysis is based on the cash flow modelling, which in turn is based on benchmarked cost of capital including the debt margin. Chapter 4 explains that the ACCC sets a benchmarked debt margin of 85 basis points assuming a credit rating of A.

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108 The ACCC considers EnergyAustralia's business profile lies between excellent and above average, given the stability of its earnings and the lack of competitors for its services.

There are many other factors used in the cash flow modelling, therefore the credit ratings estimated in table C.2 will not necessarily match the rating upon which the debt margin has been benchmarked.

C.4 Financial indicators' analysis

Submissions

EnergyAustralia raised the issue of circularity in the financial indicators' analysis attached to the draft decision. It proposed that the ACCC amend the debt margin to match the credit rating that is forecast using the financial indicators' analysis.

ACCC's considerations

The debt margin is set on the basis of a benchmarked credit rating. This input represents the ACCC's view of the debt margin of a typical business in the electricity supply industry. In this respect it is used to determine a benchmarked rate of return and does not necessarily represent EnergyAustralia's actual debt margin or credit rating.

The final credit rating determined by the financial indicators' analysis is supposed to provide an overall view of EnergyAustralia's ability to obtain credit as a stand alone transmission business.

The ACCC considers that adjusting the debt margin to match the credit rating suggested by the financial indicators is inappropriate because of the circularity. Further there are many other inputs that could be adjusted to ensure the credit rating determined by the financial indicators matches that of the debt margin benchmark. This is also inappropriate.

The financial indicators have shown that EnergyAustralia is not likely to have trouble obtaining credit. Had the financial indicators shown that EnergyAustralia would be placed in financial trouble by the revenue cap, the ACCC may have had to re-assess the MAR.

C.5 Decision

The ACCC is satisfied that, by setting an appropriate WACC, opex and capex, it has already addressed EnergyAustralia's ability to obtain credit. In determining EnergyAustralia's WACC, the ACCC benchmarks EnergyAustralia's gearing at 60 per cent and sets the debt margin based on a benchmark credit rating of 'A'.

The ACCC considers that EnergyAustralia's credit rating is likely to be above that suggested in table C.1 because of the stability of its earnings and the lack of competitors for its services. In fact, Standard and Poor's provide EnergyAustralia with a long term credit rating of 'AA'.[109]

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[109] Standard and Poor's, Australian Report Card Utilities, March 2004.

Table A.1 Financial indicators

Indicators	04–05	05–06	06–07	07–08	08–09
EBIT to Revenues (%)	61.35	62.63	62.81	63.29	63.77
EBITD to Revenues (%)	73.39	74.94	75.43	76.13	76.83
EBIT to Funds Employed (%)	8.81	9.13	9.58	9.82	10.18
EBIT to regulated assets (%)	8.81	9.13	9.58	9.82	10.18
Pre-tax interest cover (times)	2.13	2.21	2.32	2.38	2.47
Funds Flow Net Interest Cover (times)	2.55	2.65	2.79	2.86	2.97
S&P Rating [Above average business profile]	BBB	BBB	A	A	A
S&P Rating [Excellent business profile]	BBB	BBB	BBB	BBB	BBB
Funds Flow Net Debt Pay Back (years)	10.91	10.38	9.47	9.04	8.50
S&P Rating [Above average business profile]	BBB	BBB	BBB	BBB	A
S&P Rating [Excellent business profile]	BB	BB	BB	BB	BBB
Internal Financing Ratio (%)	38.82	66.12	44.56	53.77	79.60
S&P Rating [Above average business profile]	BB	A	BBB	BBB	AA
S&P Rating [Excellent business profile]	-	BBB	-	BBB	A
Gearing	0.60	0.60	0.60	0.60	0.60
Payout Ratio	61.09	61.09	61.09	61.09	61.09

Table A.2 Standard and Poor's key indicators

Utility business profile	Funds flow interest cover (times)				Funds flow net debt payback (years)				Internal financing ratio (per cent)			
	AAA	AA	A	BBB	AAA	AA	A	BBB	AAA	AA	A	BBB
Excellent	4.00	3.25	2.75	1.50	4.0	6.0	9.0	12.0	100	70	60	40
Above average	4.25	3.50	3.00	2.00	3.5	5.0	7.0	9.0	100	80	70	50
Average	5.00	4.00	3.25	2.50	3.0	4.0	5.5	7.0	100	100	90	55
Below average	-	4.25	3.50	3.00	-	4.0	5.5	7.0	-	100	100	75
Vulnerable	-	-	4.00	3.50	-	-	4.0	6.0	-	-	100+	90

Note:

AAA Extremely strong capacity to meet financial commitments.

AA Very strong capacity to meet financial commitments.

A Strong capacity to meet financial commitments but somewhat susceptible to adverse economic conditions and changes in circumstances.

BBB Adequate capacity to meet financial commitments but more susceptible to adverse economic conditions however is not considered vulnerable.

Ratings in the BB, B, CCC, CC and C categories are regarded as having significant speculative business, financial and economic conditions.

Table A.3 Financial ratio formulae

EBIT/funds employed	Earnings Before Interest and Tax/(debt + equity)
Dividend payout ratio	Dividends/Net Profit After Tax (NPAT)
Funds flow interest cover	(NPAT + depreciation + interest + tax)/interest
Funds flow net debt pay back	(Debt - (investments + cash))/(NPAT + depreciation)
Internal financing ratio	(NPAT + depreciation - dividends)/capex
Pre-tax interest cover	EBIT/interest
Gearing	Debt/(debt + equity)

Appendix D Service standards

Measure 1a Transmission circuit availability (ACCC's measure)

Sub-measures	Transmission feeders Transmission transformers Transmission reactive
Unit of measure	Percentage of total possible hours available.
Source of data	TNSP outage reports and system for circuit availability
Definition/formula	Formula: $\left(\frac{\text{No. hours per annum defined (critical/non - critical) circuits are available}}{\text{Total possible no. of defined circuit hours}}\right)\times 100$ Definition: The actual circuit hours available for defined transmission circuits divided by the total possible defined circuit hours available. Events will be capped at 14 days.
Exclusions	Exclude unregulated transmission assets. Exclude from 'circuit unavailability' any outages shown to be caused by a fault or other event on a '3rd party system' e.g. intertrip signal, generator outage, customer installation (TNSP to provide list) Excluded force majeure events
Inclusions	'Circuits' includes overhead lines, underground cables, power transformers, phase shifting transformers, static var compensators, capacitor banks, and any other primary transmission equipment essential for the successful operation of the transmission system (TNSP to provide lists) Circuit 'unavailability' to include outages from all causes including planned, forced and emergency events, including extreme events

Measure 1b Circuit availability (EnergyAustralia's proposed measure)

Sub-measures	MVA days of feeder availability MVA days of transmission bulk supply transformers non-availability MVAr days of reactive plant non-availability
Unit of measure	Percentage of MVA days of availability.
Source of data	TNSP outage reports and system for circuit availability
Definition/formula	Formula: $\left(\frac{\text{MVA days available}}{\text{Total MVA days}}\right)\times 100$ Definition: Total number of days that assets are unavailable for service: Where there is no recall capability due to equipment defect, or When a transmission reactive plant is taken out of service due to planned work, where the recall is greater than 24 hours. After calculating the non-availability of transmission bulk supply of transformers, EnergyAustralia proposes to translate it to a measure of availability. Events will be capped at 14 days.
Exclusions	Exclude unregulated transmission assets. Exclude from 'circuit unavailability' any outages shown to be caused by a fault or other event on a '3rd party system' e.g. intertrip signal, generator outage, customer installation (TNSP to provide list) Excluded force majeure events
Inclusions	'Circuits' includes overhead lines, underground cables, power transformers, phase shifting transformers, static var compensators, capacitor banks, and any other primary transmission equipment essential for the successful operation of the transmission system (TNSP to provide lists) Circuit 'unavailability' to include outages from all causes including planned, forced and emergency events, including extreme events

Measure 2 Loss of supply event frequency index (EnergyAustralia’s proposed measure)

Unit of measure	Number of incidents and/or MVA lost load and/or minutes or hours.
Source of data	TNSP outage reports and system for circuit availability
Definition/formula	Number of events greater than x system minutes per annum Number of events greater than y system minutes per annum Such that: - a x system minutes event has a return period of one year - a y system minutes event has a return period of two years
Exclusions	Exclude unregulated transmission assets (e.g. some connection assets) Exclude any outages shown to be caused by a fault or other event on a ‘third party system’, e.g. intertrip signal, generator outage, customer installation Exclude planned outages Excluded force majeure events
Inclusions	Includes all unplanned outages exceeding the specified impact (that is, x minutes and y minutes) Includes outages on all parts of the regulated transmission system Includes extreme events

Measure 3 Hours that planned outage plans were in place (EnergyAustralia's proposed measure)

Unit of measure	Hours and MVA/MWh
Source of data	TNSP Outage Reporting System
Definition/formula	Formula: $\frac{\text{Aggregate minutes duration of all unplanned outages}}{\text{No. of events}}$ Definition: Hours that plans were in place, and MVA/MWh that would have been shed in the event of a further contingency.
Exclusions	Planned outages Excludes momentary interruptions (< one minute) Excluded force majeure events
Inclusions	Includes faults on all parts of the transmission system (connection assets, interconnected system assets) Includes all forced and fault outages whether or not loss of supply occurs

D.1 Definition of force majeure

For the purpose of applying the service standards performance-incentive scheme, 'force majeure events' means any event, act or circumstance or combination of events, acts and circumstances which (despite the observance of good electricity industry practice) is beyond the reasonable control of the party affected by any such event, which may include, without limitation, the following:

- fire, lightning, explosion, flood, earthquake, storm, cyclone, action of the elements, riots, civil commotion, malicious damage, natural disaster, sabotage, act of a public enemy, act of God, war (declared or undeclared), blockage, revolution, radioactive contamination, toxic or dangerous chemical contamination or force of nature
- action or inaction by a court, government agency (including denial, refusal or failure to grant any authorisation, despite timely best endeavour to obtain same)
- strikes, lockouts, industrial and/or labour disputes and/or difficulties, work bans, blockades or picketing

- acts or omissions (other than a failure to pay money) of a party other than the TNSP which party either is connected to or uses the high voltage grid or is directly connected to or uses a system for the supply of electricity which in turn is connected to the high voltage grid

- where those acts or omissions affect the ability of the TNSP to perform its obligations under the service standard by virtue of that direct or indirect connection to or use of the high voltage grid.

In determining what force majeure events should be ‘Excluded force majeure events’ the ACCC will consider the following:

- Was the event unforeseeable and its impact extraordinary, uncontrollable and not manageable?

- Does the event occur frequently? If so how did the impact of the particular event differ?

- Could the TNSP, in practice, have prevented the impact (not necessarily the event itself)?

- Could the TNSP have effectively reduced the impact of the event by adopting better practices?

Appendix E Pass-through rules

Energy Australia Transmission Network Revenue Cap

Pass Through Rules

The pass through rules commencing on the following page form part of the revenue cap set by the ACCC for EnergyAustralia for the period 1 July 2004 to 30 June 2009.

E.1 Introduction

In accordance with clause 6.2.4(b) of the National Electricity Code ('Code'), the Australian Competition and Consumer Commission (*ACCC*) in a final decision dated 20 April 2005 ('Date of Determination') set a *revenue cap* ('Revenue Cap') to apply to EnergyAustralia ('TNSP') for the *regulatory control period* ('Regulatory Control Period') from 1 July 2004 ('Commencement Date') to 30 June 2009 ('End Date'). The Revenue Cap includes the following Pass Through Rules.

E.2 Regulated Pass Through

E.2.1 Rules form part of Revenue Cap

These Pass Through Rules form part of the Revenue Cap. Any Pass Through Amount determined under these Pass Through Rules forms part of the Maximum Allowed Revenue determined by the Revenue Cap.

E.2.2 Pass Through Events

Each of the following is a Pass Through Event:

(a) a Change in Taxes Event;

(b) an Insurance Event;

(c) a Network (Grid) Support Event;

(d) a Service Standards Event; and

(e) a Terrorism Event.

E.2.3 Entitlement or requirement to Pass Through

If:

a) a Pass Through Event takes effect or will take effect on or before the End Date; and

b) the Pass Through Event has a financial impact on the TNSP during the Regulatory Control Period,

then, if the Pass Through Amount (being the amount determined by clause 2.4) for that Pass Through Event is:

a) positive, the TNSP is entitled to increase its Maximum Allowed Revenue by that Pass Through Amount provided that the procedure set out in clause 3 is satisfied; or

b) negative, the TNSP must follow the procedure set out in clause 3, and, in any event, must decrease its Maximum Allowed Revenue by that Pass Through Amount.

E.2.4 Pass Through Amount

The Pass Through Amount for a Pass Through Event is the increase or decrease in the Maximum Allowed Revenue over one or more *financial years*, required to ensure that the net financial effect of the Pass Through Event on the TNSP's provision of *prescribed services* during the Regulatory Control Period is neutral, taking into account the following factors:

(a) The Pass Through Amount (whether it be positive or negative) must be material.

(b) The Pass Through Amount must be adjusted by the extent to which:

  (i) where the Pass Through Amount is positive:

    (1) the Pass Through Event was caused or aggravated by any act or omission of the TNSP that is inconsistent with *good electricity industry practice*; and

    (2) the TNSP failed to take all steps that would be consistent with *good electricity industry practice* to remedy or abate the Pass Through Event; or

  (ii) where the Pass Through Amount is negative, any act or omission of the TNSP that is inconsistent with *good electricity industry practice* reduced the net financial effect of the Pass Through Event.

(c) The Pass Through Amount must take into account the time cost of money.

(d) The Pass Through Amount must take into account the amount (if any) for such a Pass Through Event included in the operating expenses or other inputs used to determine the Revenue Cap.

(e) Without limiting the generality of clauses 2.4(a)-(d), in relation to a Change in Taxes Event, the Pass Through Amount must take into account the amount of any increase or decrease in another tax, rate, duty, charge, levy, rebate, Authority fee or other like or analogous impost which offsets or will offset in whole or in part the financial effect on the TNSP of the relevant Change in Taxes Event (and the manner in which, and the period over which, that increase or decrease occurs).

(f) Without limiting the generality of clauses 2.4(a)-(d), in relation to an Insurance Event, the Pass Through Amount must take into account:

  (i) any material increase or decrease in premium paid or required to be paid by the TNSP as compared to the premium that was provided for in the Revenue Cap in relation to that risk;

  (ii) any material deductible incurred or that will be incurred by the TNSP as compared to the allowance for the deductible (if any) that was provided for in the Revenue Cap in relation to that risk; and/or

(iii) if the Insurance Event occurs and the TNSP either does not continue the relevant Insurance or continues the Insurance on different terms, any material losses resulting from any uninsured event where that event would have been insured or would have been fully insured by the Insurance that was provided for in the Revenue Cap in relation to that risk (but only if the TNSP is able to demonstrate that the TNSP's decision not to continue the relevant Insurance or to continue the Insurance on different terms (as the case may be) was consistent with *good electricity industry practice*).

(g) Without limiting the generality of clauses 2.4(a)-(d), in relation to a Network (Grid) Support Event, the Pass Through Amount must take into account any material costs (including all reasonable project feasibility and management costs) resulting from the Network (Grid) Support Event.

(h) Without limiting the generality of clauses 2.4(a)-(d), in relation to a Service Standards Event, the Pass Through Amount must take into account any material costs resulting from the Service Standards Event.

(i) Without limiting the generality of clauses 2.4(a)-(d), in relation to a Terrorism Event, the Pass Through Amount must take into account any material loss, damage, cost or expense directly resulting from:

(i) the Terrorism Event; or

(ii) action taken in controlling, preventing or suppressing the Terrorism Event.

E.2.5 Period and form of Pass Through Amount

(a) Subject to clauses 2.5(b)-(d):

(i) the period over which the Pass Through Amount is to be recovered; and

(ii) if the period over which the Pass Through Amount is to be recovered consists of two or more *financial years*, the allocation of the Pass Through Amount over those *financial years* (being the form of the Pass Through Amount),

are to be determined by the TNSP.

(b) The period and form applied by the TNSP under clause 3.6(b) must have been specified by:

(i) the TNSP in a Notice of Proposed Pass Through under clause 3.2; or

(ii) the *ACCC* in notice to the TNSP under clause 3.5.

(c) The first day of the period:

(i) must be the start of a *financial year*;

(ii) must not be a date earlier than the Commencement Date;

(iii) where the Pass Through Amount is positive, must not be a date earlier than the date upon which the procedure set out in clause 3 is satisfied;

(iv) where the Pass Through Amount is positive and the date upon which the procedure set out in clause 3 is satisfied falls within the period commencing on 15 May and ending on 30 June, must be a date after 1 July of that year; and

Note: For example, if the procedure set out in clause 3 is satisfied on 31 May 2005, the first *financial year* in which the Maximum Allowed Revenue could be varied to include the Pass Through Amount would be 1 July 2006 to 30 June 2007. This is because clause 6.5.7 of the Code requires *Transmission Network Service Providers* to publish the *transmission service* prices to apply for the following *financial year* by 15 May each year.

(v) must not be a date after the End Date.

(d) The last day of the period:

(i) must be the end of a *financial year*; and

(ii) must not be a date after the End Date.

E.3 Procedure

E.3.1 Initiation of Pass Through

If:

(a) a Pass Through Event takes effect or will take effect on or before the End Date; and

(b) the Pass Through Event has a financial impact on the TNSP during the Regulatory Control Period,

then, if the Pass Through Amount for that Pass Through Event is:

(c) positive, the TNSP may give a Notice of Proposed Pass Through to the *ACCC* in accordance with clause 3.2; or

(d) negative, the TNSP must promptly (and, in any event, within three *months* of the TNSP becoming aware that the Pass Through Event had taken effect or will take effect (as the case may be)) give a Notice of Proposed Pass Through to the *ACCC* in accordance with clause 3.2.

E.3.2 Notice of Proposed Pass Through

A Notice of Proposed Pass Through must include:

(a) a description of the relevant Pass Through Event;

(b) the date on which the relevant Pass Through Event took effect or will take effect;

(c) if the Notice of Proposed Pass Through is provided under clause 3.1(d), the date on which the TNSP first became aware that the Pass Through Event had taken effect or will take effect;

(d) the estimated financial effect of the Pass Through Event on the TNSP's provision of *prescribed services* (being the proposed Pass Through Amount);

(e) the proposed period over which the Pass Through Amount should apply;

(f) if the proposed period over which the Pass Through Amount should apply consists of two or more *financial years*, the proposed allocation of the Pass Through Amount over the *financial years*; and

(g) the supporting information referred to in clauses 3.3(a) and (b).

E.3.3 Provision of information

(a) The TNSP must attach to its Notice of Proposed Pass Through such information and documentation as the *ACCC* requires to enable the *ACCC* to form an opinion as to:

(i) whether a Pass Through Event did take effect or will take effect;

(ii) if the Notice of Proposed Pass Through is provided under clause 3.1(d), whether the TNSP complied with the requirement to give promptly such Notice to the *ACCC*;

(iii) whether, and to what extent, the TNSP's Maximum Allowed Revenue should be varied as a result of the Pass Through Event (being the Pass Through Amount);

(iv) the period over which the Pass Through Amount should apply; and

(v) if the period over which the Pass Through Amount should apply consists of two or more *financial years*, how the Pass Through Amount should be allocated over the *financial years*.

(b) Without limiting the generality of the obligation in clause 3.3(a), the supporting information must include, where the Pass Through Event is:

(i) a Change in Taxes Event – the relevant instrument before the Change in Taxes Event and the relevant instrument implementing the Change in Taxes Event;

(ii) an Insurance Event – the relevant insurance policy, cover note and premium invoice (as the case may be) before the Insurance Event and the relevant insurance policy, cover note and premium invoice (as the case may be) implementing the Insurance Event;

(iii) a Network (Grid) Support Event – if applicable, the relevant decision of *NEMMCO* or other Authority before the Network (Grid) Support Event and the relevant decision of *NEMMCO* or other Authority implementing the Network (Grid) Support Event;

(iv) a Service Standards Event – the relevant decision or Applicable Law before the Service Standards Event and the relevant decision or Applicable Law implementing the Service Standard Event.

(c) Regardless of whether a Notice of Proposed Pass Through has been given, the TNSP must, in relation to risks that were covered by the TNSP's Insurances that were provided for in the Revenue Cap:

(i) provide to the *ACCC*, within one *month* after the Date of Determination or Commencement Date (whichever is later), a copy of the TNSP's insurance policies, cover notes and premium invoices:

(1) upon which the Revenue Cap was set; and

(2) as at the Commencement Date (if different from the documents referred to in clause 3.3(c)(i)(1)); and

(ii) at the time of providing to the *ACCC* the annual reporting information prescribed in the *ACCC's* Information Requirements Guidelines, provide to the *ACCC* a copy of any of the TNSP's insurance policies, cover notes and premium invoices that are different from those previously provided to the *ACCC* in accordance with clause 3.3(c).

E.3.4 Procedure to be followed by ACCC

(a) In considering a Notice of Proposed Pass Through, the *ACCC* may decide to seek public comment on the Notice.

(b) Disclosure by the *ACCC* of the supporting information provided by the *TNSP* in accordance with clauses 3.2(g) and 3.3 shall be governed by the procedure set out in clauses 6.2.5(e) and 6.2.6 of the Code.

E.3.5 Verification by ACCC

(a) The *ACCC* will, within the Assessment Period, form an opinion on:

(i) if the Notice of Proposed Pass Through was provided under clause 3.1(d), whether the TNSP complied with the requirement to give promptly such Notice to the *ACCC*;

(ii) whether the Pass Through Event specified in the Notice of Proposed Pass Through did take effect or will take effect;

(iii) if so, the Pass Through Amount (if any) in respect of the relevant Pass Through Event (determined in accordance with clause 2.4);

(iv) the period over which the Pass Through Amount should be applied (which must satisfy clauses 2.5(c) and (d)); and

(v) if the period over which the Pass Through Amount should be applied consists of two or more *financial years*, how the Pass Through Amount should be allocated over the *financial years*,

and notify the TNSP in writing of the *ACCC's* opinion.

Note: If the TNSP disputes the *ACCC's* findings referred to in:

(a) clauses 3.5(a)(ii) and/or (iii), the TNSP may seek judicial review of the relevant finding;

(b) clauses 3.5(a)(iv) and/or (v), the TNSP may determine the period over, and form in which, the Pass Through Amount set out in the *ACCC's* notice will be applied (subject to the requirements of clause 2.5). This may require the TNSP to give the *ACCC* a further Notice of Proposed Pass Through.

(b) If the *ACCC* does not give notice to the TNSP under clause 3.5(a) on or before the last day of the Assessment Period, then the *ACCC* is taken to have notified the TNSP of its opinion that the Pass Through Amount (and the period over, and form in, which the TNSP will apply the Pass Through Amount) should be as specified by the TNSP in the Notice of Proposed Pass Through.

E.3.6 Application of Pass Through Amount

(a) If the TNSP has received or is taken to have received a notice under clause 3.5, the TNSP must promptly notify its affected customers and *Co-ordinating Network Service Provider* (if applicable) of:

(i) the Pass Through Amount (if any) set out in the notice from the *ACCC* under clause 3.5; and

(ii) the period over, and form in, which the Pass Through Amount is to be applied (to be determined by the TNSP in accordance with clause 2.5).

(b) Where the Pass Through Amount is:

(i) positive, the TNSP may, in accordance with clause 2.3(c), after providing notice in accordance with clause 3.6(a), increase its Maximum Allowed Revenue by the Pass Through Amount over the period, and in the form, specified by the TNSP in the notice under clause 3.6(a);

(ii) negative, the TNSP must, in accordance with clause 2.3(d), regardless of whether or not the TNSP has provided notice in accordance with clause 3.6(a), decrease its Maximum Allowed Revenue by the Pass

Through Amount specified or taken to be specified in the notice from the *ACCC* under clause 3.5 over the period, and in the form to be determined by the TNSP in accordance with clause 2.5.

E.4 Definitions

E.4.1 Code definitions

In these Pass Through Rules, unless the context otherwise requires:

(a) words appearing in italics have the meaning assigned to them from time to time by the Code; and

(b) if a word in italics is no longer defined in the Code, it will have the meaning last assigned to it by the Code.

E.4.2 Additional definitions

In these Pass Through Rules, unless the context otherwise requires:

Applicable Law means any legislation, delegated legislation (including regulations), codes, licences, guidelines, determinations and directions relating to the provision of one or more *prescribed services*, and includes the Code and the National Electricity Law.

Assessment Period means:

(a) two *months* from the date the *ACC*C receives from the TNSP a Notice of Proposed Pass Through that satisfies the requirements of clauses 3.2 and 3.3; or

(b) if the *ACCC* so notifies the TNSP prior to the expiry of the initial two *month* period, four *months* from the date the *ACC*C receives from the TNSP a Notice of Proposed Pass Through that satisfies the requirements of clauses 3.2 and 3.3.

Note: For example, if the *ACCC* receives from the TNSP a valid Notice of Proposed Pass Through on 31 May 2005, the TNSP must receive written notice of the *ACCC's* opinion on or before 31 July 2005 (or 30 September 2005 in the event that the initial period is extended).

Authority means any government department, instrumentality, minister, agency, statutory authority or other body in which a government has a controlling interest, and includes *NECA*, *NEMMCO* and the *ACCC* and their successors.

Change in Taxes Event means:

(a) a change in the way or rate at which a Relevant Tax is calculated (including a change in the application or official interpretation of a Relevant Tax); or

(b) the removal of a Relevant Tax or imposition of a new Relevant Tax, to the extent that the financial effect of the change, removal or imposition results in a material change in the amount the TNSP is required to pay or is taken to pay during the Regulatory Control Period as compared to the allowance that was provided for in the Revenue Cap.

Code means the ‘National Electricity Code’ as defined in the National Electricity Law set out in the schedule to the *National Electricity (South Australia) Act 1996* (SA).

Commencement Date means 1 July 2004, being the first day of the period covered by the Revenue Cap.

Date of Determination means 20 April 2005, being the date of the *ACCC’s* final decision setting the Revenue Cap.

End Date means 30 June 2009, being the last day of the period covered by the Revenue Cap.

Information Requirements Guidelines means the ‘Information Requirements Guidelines’ issued by the *ACCC* under clause 6.2.5 of the Code on 5 June 2002 (including any subsequent amendment or replacement).

Insurance means insurance whether under a policy or a cover note or other similar arrangement.

An **Insurance Event** occurs where, in relation to a risk that was the subject of Insurance and for which a premium was provided for in the Revenue Cap:

(a) the cost of the premium paid or required to be paid by the TNSP becomes materially higher or lower than the premium that was provided for in the Revenue Cap;

(b) the risk eventuates and the TNSP incurs or will incur all or part of a deductible (where that amount is materially higher or lower than the allowance for the deductible (if any) that was provided for in the Revenue Cap);

Note: For the avoidance of doubt, clause (b) requires confirmation from the relevant insurance provider that the risk comes within the scope of the relevant Insurance.

(c) Insurance becomes unavailable to the TNSP; and/or

(d) Insurance becomes available to the TNSP on terms materially different from those upon which the Revenue Cap was set,

provided that the TNSP is able to demonstrate that no act or omission of the TNSP which is inconsistent with *good electricity industry practice* caused or aggravated the occurrence of that event.

Maximum Allowed Revenue is the amount referred to in clause 6.3 of the Code (which is determined by the Revenue Cap).

A **Network (Grid) Support Event** occurs where the cost of *network* support becomes materially higher or lower than the per annum cost of *network* support (if any) provided by the *ACCC* in the Revenue Cap. For example, this may occur where:

(a) the TNSP agrees, or acquires an option, to purchase services from *generators* (as referenced in clauses 5.6.2(m) and 6.2.4(c)(7) of the Code) or *customers* to effect the efficient operation, maintenance or development of its *transmission system*, where the payments are a cost-effective and practical substitute for *network augmentation*; or

(b) *NEMMCO* or some other Authority causes costs, obligations or liabilities for *network* support to be imposed or removed (or varied if previously imposed) on the TNSP in respect of the operation of the *transmission system*.

Notice of Proposed Pass Through means a notice described in clause 3.2.

Pass Through Amount means a variation to the TNSP's Maximum Allowed Revenue as a result of a Pass Through Event determined in accordance with these Pass Through Rules (which form part of the TNSP's Revenue Cap). A Pass Through Amount may be positive or negative.

Pass Through Events means the events specified in clause 2.2:

Regulatory Control Period means the period starting on the Commencement Date and ending on the End Date.

Relevant Tax means any tax, rate, duty, charge, levy, rebate, Authority fee or other like or analogous impost that is:

(a) paid, to be paid, or taken to be paid by the TNSP in connection with the provision of *prescribed services*; or

(b) included in the operating expenses or other inputs used to determine the Revenue Cap,

but excludes:

(c) income tax (or State equivalent tax) and capital gains tax;

(d) penalties and fines (including penalties and interest for late payment relating to any tax, rate, duty, charge, levy, Authority fee or other like or analogous impost);

(e) charges and Authority fees paid or payable in respect of a Service Standards Event;

(f) stamp duty, financial institutions duty, bank accounts debits tax or similar taxes or duties;

(g) any tax, rate, duty, charge, levy, rebate, Authority fee or other like or analogous impost which replaces the imposts referred to in (c) to (f).

Revenue Cap means the *revenue cap* set by the *ACCC* in accordance with clause 6.2.4(b) of the Code in a final decision issued on the Date of Determination to apply to the TNSP for the Regulatory Control Period.

Service Standards Event means a decision made by any Authority or any introduction of or amendment to an Applicable Law that:

(a) has the effect of:

  (i) imposing, removing or varying minimum standards on the TNSP relating to *prescribed services*;

  (ii) altering the nature or scope of services that comprise the *prescribed services*;

  (iii) varying the manner in which the TNSP is required to undertake any activity forming part of *prescribed services*; or

  (iv) increasing or decreasing the TNSP's risk in providing the *prescribed services*,

  from that upon which the Revenue Cap was set; and

(b) results or will result in the TNSP incurring materially higher or lower costs in providing *prescribed services* than would have been incurred but for that event.

Terrorism Event means an act including but not limited to the use of force or violence and/or the threat thereof, of any person or group(s) of persons, whether acting alone or on behalf of or in connection with any organisation(s) or government(s), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons, including the intention to influence any government and/or to put the public, or any section of the public, in fear.

TNSP means EnergyAustralia (ABN 67505337385).

E.4.3 References to certain general terms

Unless the contrary intention appears, a reference in these Pass Through Rules to:

(a) **(variations or replacement)** a document (including these Pass Through Rules) includes any variation or replacement of it;

(b) **(clauses)** a clause is a reference to a clause in these Pass Through Rules;

(c) **(reference to statutes)** a statute, ordinance, code or other law includes regulations and other instruments under it and consolidations, amendments, re-enactments or replacements of any of them;

(d) **(singular includes plural)** the singular includes the plural and vice versa;

(e) **(person)** the word ‘person’ includes an individual, a firm, a body corporate, a partnership, joint venture, syndicate, an unincorporated body or association, or any Authority;

(f) **(successors)** a particular person includes a reference to the person’s successors, substitutes (including persons taking by novation) and assigns;

(g) **(meaning not limited)** the words ‘include’, ‘including’, ‘for example’ or ‘such as’ are not used as, nor are they to be interpreted as, words of limitation, and, when introducing an example, do not limit the meaning of the words to which the example relates to that example or examples of a similar kind;

(h) **(reference to anything)** anything (including any amount) is a reference to the whole and each part of it.

4.4 Headings

Headings (including those in brackets at the beginning of paragraphs) are for convenience only and do not affect the interpretation of these Pass Through Rules.