Draft decision

TransGrid transmission determination 2009–10 to 2013–14

31 October 2008

AUSTRALIAN ENERGY REGULATOR

Request for Submissions

This document sets out the Australian Energy Regulator's (AER) draft transmission determination for TransGrid for the period 1 July 2009 to 30 June 2014.

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

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

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

Alternatively, submissions can be mailed to:

Mike Buckley
General Manager
Network Regulation North
Australian Energy Regulator
GPO Box 3131
Canberra ACT 2601

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

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

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

A copy of TransGrid's revenue proposal, proposed negotiating framework, proposed pricing methodology, consultancy reports and submissions from interested parties are available on the AER website.

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

Contents

Shortened forms

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
CPI	consumer price index
current regulatory control period	1 July 2004 to 30 June 2009
NEL	National Electricity Law
NEM	National Electricity Market
NER	National Electricity Rules
next regulatory control period	1 July 2009 to 30 June 2014
opex	operating expenditure
PB	Parsons Brinckerhoff Australia Pty Ltd
TNSP	transmission network service provider

This page has intentionally been left blank

Overview

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

The AER has assessed TransGrid's 2009–2014 revenue proposal to determine if it is in accordance with the requirements of the NER. Expert engineering consultants as well as financial and economic experts assisted the AER in making its assessment. This assessment considered TransGrid's past performance in maintaining its network, and the effectiveness and application of its policies and procedures, both in terms of past performance and for the development of its network. TransGrid's revenue proposal would lead to transmission charges increasing by 4.0 per cent per annum ($2008–09).

Engineering consultant Parsons Brinckerhoff Australia Pty Ltd (PB) was engaged by the AER to assist in making its assessment. PB has considerable experience in reviewing the performance and operating requirements of Australian energy businesses and has previously undertaken this role for the AER. PB assessed TransGrid's proposal to establish the necessity of the proposed expenditure and reasonableness of its expected cost. This assessment included a bottom up review of proposed programs and unit costs, as well as benchmark assessments of TransGrid's costs and performance compared with other businesses.

During the review PB and AER staff visited TransGrid to inspect supporting documentation such as planning documents, manuals and financial models. As part of this process senior TransGrid staff were questioned on the assumptions underpinning the revenue proposal and its implementation. This process assisted PB and the AER to satisfy itself that the revenue proposal was soundly based and that appropriate policies and procedures had been established to deliver the proposed capital works.

The AER, for the most part, has accepted the need for the substantial capital works proposed by TransGrid over the next regulatory control period. Essentially, increased capital expenditure is needed in NSW to:

- augment the network to accommodate the growth in maximum demand for energy
- replace ageing assets
- improve network security and reliability.

However, in some areas the AER has determined that TransGrid's proposed expenditure does not reflect the reasonable costs a prudent operator in the circumstances of TransGrid would require to meet the capital expenditure criteria set out in the NER. To reflect this position, the AER has reduced TransGrid's proposed expenditure in some areas.

Of particular note, the AER has not accepted TransGrid's proposal to amend the methodology used to escalate future labour and materials cost inputs. The AER has, as part of recent determinations, developed a methodology to take account of the

commodities boom on materials' prices and labour costs. For the reasons detailed in this draft decision, the AER has not accepted TransGrid's proposed modification to this methodology. The AER will, however, review the data used to estimate input cost escalators as part of its final determination in order to take account of forecasts of future movements in commodity prices.

After assessing TransGrid's revenue proposal against the requirements of the NER, the AER has determined that the capital expenditure proposed by TransGrid is greater than the amount required to meet the capital expenditure criteria. The AER has therefore determined that TransGrid's proposed capital expenditure of $2.55 billion ($2007–08) should be reduced to $2.38 billion. An indicative contingent projects allowance of $1.2 billion has also been approved by the AER.

PB has also confirmed the need to approve higher operating expenditures over the next regulatory control period. This reflects the increased size of TransGrid's network and higher labour costs.

In the ten years to 2007–08, real wages growth in the electricity, gas and water sector in NSW exceeded growth in economy-wide real wages by an average of 0.8 per cent per annum. Labour costs in the utilities sector are forecast to continue to exceed the economy-wide average over the course of the next regulatory control period.

After assessing TransGrid's revenue proposal, the AER has determined that an operating expenditure allowance of $765 million reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to meet the operating expenditure objectives. This amount represents an increase of 8.9 per cent compared with TransGrid's level of operating expenditures in the current regulatory control period.

PB also assisted the AER in its assessment of the service component of TransGrid's service standards for the next regulatory control period. During the current regulatory control period, TransGrid performed well against its service standard targets and as a result most service component parameter targets have been raised for the next regulatory control period. The market impact component of the service standards scheme will apply to TransGrid during the next regulatory control period. It supplements the service component by targeting outages that have an adverse impact on generator dispatch outcomes.

Outcome of regulatory process

As a result of the regulatory review process, over the course of the next regulatory control period, TransGrid will significantly increase investment in its transmission network. This will result in real increases in transmission charges and higher electricity prices for consumers. The AER has estimated that the increase in average transmission charges under this draft decision will add approximately $4.00 to the average residential customer's annual bill of $983 (0.4 per cent).

In part, higher electricity charges are a result of the maximum demand for electricity increasing at a faster rate than overall energy consumption. The need to expand the network to meet higher peaks in demand reduces the efficiency of the network and increases the cost of supplying electricity. Over the next regulatory control period

maximum demand is expected to increase by 2.5 per cent per year whereas energy consumption will grow by 0.8 per cent per year. Growth in the use of air conditioning is a significant underlying factor. The AER's draft decision includes an allowance for TransGrid to support demand management initiatives.

The global financial crisis may also impact on the price of electricity by raising the weighted average cost of capital used to determine TransGrid's maximum allowed revenue. The cost of capital has fluctuated from around 9 per cent in early 2007, up to around 11 per cent in mid-2008. However, since then the cost of capital has fallen to 9.82 per cent, as at 17 October 2008. The cost of capital used to determine TransGrid's future revenue will be determined closer to the time of the AER's final determination. If global financial conditions improve in the interim period, and the commercial debt risk premium subsequently declines this will be reflected in a lower cost of capital for TransGrid, and lower electricity prices for consumers.

Summary

Introduction

In 2005, the Australian Competition and Consumer Commission (ACCC) determined TransGrid's revenue cap for a five year period from 1 July 2004 to 30 June 2009 (the current regulatory control period). The AER assumed responsibility for regulating electricity transmission services provided by TransGrid on 1 July 2005.

The AER is required to provide TransGrid with sufficient revenues to meet the efficient costs of maintaining and developing the New South Wales transmission network, given the forecast growth in demand for electricity transmission services.

The AER is required to make a transmission determination for TransGrid according to chapter 6A of the National Electricity Rules (NER) in respect of:

- prescribed transmission services
- negotiated transmission services.

The AER published TransGrid's revenue proposal, proposed negotiating framework and proposed pricing methodology together with the AER's proposed negotiated transmission service criteria on 26 June 2008. Interested parties were invited to make a submission on all documents. Four submissions were received. A public forum on TransGrid's revenue proposal was held in Sydney on 30 July 2008.

The AER engaged Parsons Brinckerhoff Australia Pty Ltd (PB) as a technical expert to advise it on a number of key aspects of TransGrid's revenue proposal, including capex, opex and service standards. The AER engaged Nuttall Consulting to provide it with technical and engineering advice throughout the review process. The AER also engaged McLennan Magasanik Associates (MMA) to undertake a desk top review of the methods and processes used by TransGrid to develop its demand forecasts. Econtech was also commissioned to provide a forecast of NSW labour cost growth.

This draft decision should be read in conjunction with the consultants' reports.

The key components of this draft decision are:

- The AER's draft revenue determination for TransGrid in respect of the provision of prescribed transmission services, including:
    - the opening regulatory asset base (RAB) value for TransGrid
    - an assessment of the forecast capex allowance for TransGrid over the next regulatory control period
    - as estimate of the efficient benchmark weighted average cost of capital (WACC) for TransGrid
    - as assessment of the forecast opex allowance for TransGrid over the next regulatory control period

- the values to be attributed to the performance incentive scheme parameters for the purposes of the application to TransGrid of a service target performance incentive scheme

- the amount of the estimated total revenue cap for TransGrid over the next regulatory control period.

- The AER's draft decision relating to TransGrid's negotiating framework for negotiated transmission services.

- The AER's draft decision on the negotiated transmission service criteria that will apply to TransGrid.

- The AER's draft decision in relation to TransGrid's pricing methodology.

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

Regulatory requirements

National Electricity Law

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

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

National Electricity Rules

Chapter 6A of the NER sets out provisions the AER must apply in exercising its regulatory functions and powers for electricity transmission networks providing prescribed transmission services and negotiated transmission services.

Broadly, chapter 6A of the NER:

- sets out the methodology for establishing the opening RAB
- sets out the requirements for TNSPs' revenue proposals, including the requirement to forecast capex and opex necessary to meet the capex and opex objectives. These objectives include meeting the expected demand for prescribed transmission services and maintaining the quality, reliability, security and safety of the supply of prescribed transmission services and the transmission system

- requires the AER to assess whether the forecast capex and opex proposed by a TNSP reflect the efficient costs that a prudent operator in the circumstances of the relevant TNSP would require to achieve the capex or opex objectives
- requires the AER to publish an efficiency benefit sharing scheme and a service target performance incentive scheme
- sets out the methodology for calculating depreciation on the assets to be included in the RAB
- requires the AER to set the maximum allowed revenue for each year in the regulatory control period and determine the X factor to apply in each regulatory year
- requires the AER to assess the TNSP's negotiating framework, and publish negotiated transmission service criteria
- requires the AER to assess the TNSP's pricing methodology.

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

Opening regulatory asset base

TransGrid proposal

TransGrid proposed an opening RAB of $4237 million as at 1 July 2009. The proposed opening RAB includes a higher than forecast past capex amount of $1428 million expended in the latter part of the current regulatory control period.

TransGrid has used the AER's roll forward model (RFM) to determine its proposed opening RAB. In performing the roll forward of its RAB, TransGrid has reduced its RAB by the disposal book value of assets shed during the current regulatory control period and adjusted its RAB for actual inflation using the consumer price index (CPI).

TransGrid has also decreased its opening RAB value by $14 million to account for lower than estimated capex between July 2003 and June 2004 in the previous regulatory control period. Further, it has removed the return on this amount over the current regulatory control period ($7.9 million) to establish the opening RAB as at 1 July 2009.

AER conclusion

The AER reviewed inputs to the RFM for the previous regulatory control period—1 July 2003 to 30 June 2004—and is satisfied with TransGrid's proposed adjustments to the opening RAB for the current regulatory control period. In accordance with the NER, the AER accepts the adjustments to TransGrid's RAB of $14 million for the difference between actual and forecast capex, and $7.9 million associated with the foregone return on that difference.

TransGrid advised that during the current regulatory control period it has replaced some connection assets. These replacement assets were committed to be constructed after 9 February 2006 and under the NER they cannot be considered to provide

prescribed transmission services, even though the assets they replaced provided prescribed transmission services. As a result, these replacement assets provide negotiated transmission services. The NER provides that the RAB is the value of the assets used to provide prescribed transmission services. Therefore, in accordance with the NER the AER has removed the amount of $8.1 million from the RAB to account for these replacement assets.[1]

TransGrid also provided its actual capex for 2007–08, which has become available subsequent to lodgement of its revenue proposal, and an update of the expected capex for 2008–09.

Some errors were identified during the review process and these were corrected by TransGrid. The AER reviewed the updated inputs and accepts that they are appropriate for the purposes of the RFM. The net impact of these adjustments is a decrease of $3 million to TransGrid's proposed opening RAB. Accordingly, for this draft decision, the AER has determined that TransGrid's opening RAB is $4234 million for the next regulatory control period (as at 1 July 2009). The AER's RAB roll forward calculations are set out in table 1.

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

	2004–05	**2005–06**	**2006–07**	**2007–08[a]**	**2008–09[b]**
Opening RAB	3012.8	3103.9	3228.8	3397.9	3737.0
Actual net capex (adjusted for actual CPI and WACC)[c]	134.0	154.1	221.2	333.4	577.3
CPI adjustment on opening RAB	71.1	92.6	78.6	144.1	104.6
Straight-line depreciation (adjusted for actual CPI)	–113.9	–121.7	–130.8	–138.4	–155.5
Closing RAB	3103.9	3228.8	3397.9	3737.0	4263.5
Less: difference between actual and forecast capex for 2003–04					13.6
Less: return on difference[d]					7.9
Less: connection assets providing negotiated transmission services					8.1
Opening RAB at 1 July 2009					4234.0

(a) Updated for actual 2007–08 capex.
(b) Based on estimated net capex and forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.
(c) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The accounting book values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $13.6 million for 1 July 2003 to 30 June 2004.

[1] A corresponding change to the tax asset value was also made in the PTRM.

Forecast capital expenditure

TransGrid proposal

TransGrid initially proposed a capex allowance totalling $2627 million ($2007–08) for the next regulatory control period. Following the release of its 2008 Annual Planning Report (APR), TransGrid updated its proposal. TransGrid is now seeking a capex allowance of $2550 million for the next regulatory control period. Table 2 sets out the annual profile of TransGrid's initial and updated capex proposals.

Table 2: TransGrid's capex allowance ($m, 2007–08)

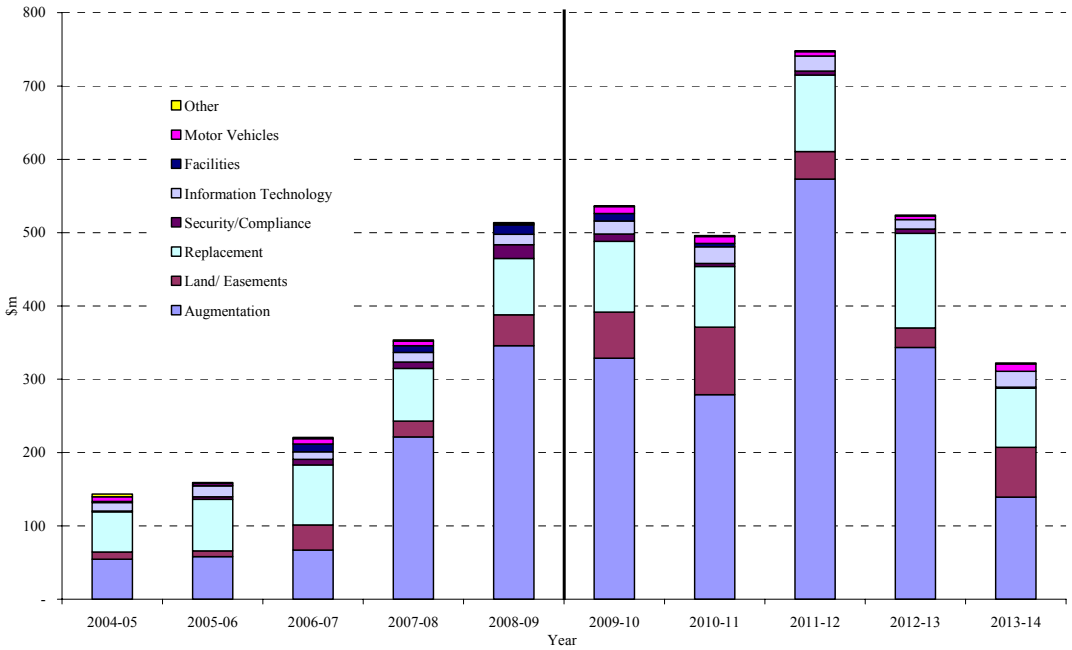
	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Initial proposed capex	536.8	495.9	748.0	523.8	322.3	2626.8
Updated proposed capex	531.9	465.9	579.2	552.3	420.6	2549.8

Source: TransGrid, *Revenue proposal*, p. 73;
TransGrid, *Updated revenue proposal*, pro-forma statements.

TransGrid's initial revenue proposal included 18 contingent projects. The indicative costs for these projects range from $35 million to $650 million, and total $2.3 billion. This total, however, excludes one project that has been identified but not costed (the system protection scheme). TransGrid's updated revenue proposal included 19 contingent projects due to TransGrid moving one project from its capex allowance to contingent projects in light of the 2008 APR information.

TransGrid's updated capex proposal is significantly higher (83 per cent in real terms) than the capex expected to be incurred during the current regulatory control period. It noted significantly higher capital investment is required due to its transmission network facing a number of network constraints that require capital intensive solutions. A comparison of the capex incurred in the current regulatory control period and that being sought in the next regulatory control period is shown in figure 1.

Figure 1: Historical and forecast capex by category ($m, 2007–08)



Source: TransGrid, *Updated revenue proposal*, pro-forma statements. Data converted to 2007−08 dollar terms using data from ABS Cat no: 6401.0, Consumer Price Index, Australia.

Some of the drivers of TransGrid's capex proposal include:

- the age profile of its infrastructure
- planning obligations—in particular, the NSW requirement for DNSPs to plan to 'n–1' for all loads greater than 15 MVA means TransGrid's network needs to be similarly planned
- several large augmentation projects to meet the growing demand for electricity within its geographic market.

Price of work cost drivers include:

- the rising real price of electricity transmission equipment
- rising real wages growth and increasing compliance requirements associated with community and environmental obligations.

AER conclusion

The AER is not satisfied that the capex allowance proposed by TransGrid reasonably reflects the capex criteria set out in the NER, taking into account the capex factors. Because of this, the AER must not accept the forecast capex in TransGrid's revenue proposal.

The AER has formed its conclusion based on PB's assessment of a sample of TransGrid's network and non-network projects, its replacement program and its project costing and escalation processes.

PB's assessment determined that while TransGrid generally operates consistent with good industry practice in terms of corporate governance and project delivery there are weaknesses with respect to its assessment of project options and the assessment of project risks.

The AER undertook its own analysis of TransGrid's unit cost escalators and has assessed them as not being likely to reflect efficient costs.

On the basis of its analysis of TransGrid's proposed capex forecast and the advice of PB, the AER has reduced the capex allowance proposed by TransGrid by $173 million ($2007–08). This represents a reduction of 6.8 per cent of TransGrid's forecast capex of $2550 million and will result in an amended forecast capex allowance of $2376 million.[2] In addition, the AER has approved an indicative contingent projects allowance of $1.2 billion.

Table 3 shows the AER's conclusions on the capex allowance being sought by TransGrid.

Table 3: AER's conclusion on TransGrid's capex allowance ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's updated proposal	531.9	465.9	579.2	552.3	420.6	2549.8
Adjustments resulting from detailed project review	3.2	–14.0	–15.4	–19.7	–31.4	–77.2
Replacement programs	–0.8	–2.0	–1.0	–0.9	–0.9	–5.6
Adjustment to cost accumulation process[a]	–6.4	–9.1	–12.6	–16.9	–15.0	–59.9
Application of annual escalators	0.6	–0.1	–6.3	–2.4	3.5	–4.7
Adjustment to cost estimation risk factor	–2.3	–2.0	–2.6	–2.5	–1.8	–11.4
Agreed adjustments (not included in TG's updated proposal)	–0.2	–0.2	–0.4	–0.2	⁻0.3	–1.2
Cost estimating factors adjustment	–2.8	–2.4	–3.0	–2.9	–2.2	–13.3
AER's total adjustments	–8.7	–29.4	–41.1	–45.6	–48.1	–173.3
AER's capex allowance	523.5	436.1	538.1	506.5	372.4	2376.5

Note: Totals may not add up due to rounding.
(a) This includes adjustments to labour and materials cost escalators.

[2] The forecast capex allowance is $2443 million in 2008–09 dollar terms.

This allowance represents the AER's estimate of the total capex that a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives. The AER is satisfied that the capex forecast of $2376 million over the next regulatory control period reasonably reflects the capex criteria, taking into account the capex factors.

Cost of capital

TransGrid proposal

In estimating the WACC for its revenue proposal, TransGrid has used the values for the WACC parameters set out in the NER. For the purposes of its revenue proposal TransGrid has calculated a nominal vanilla WACC of 9.15 per cent.

AER conclusion

For this draft decision, the AER has determined a nominal vanilla WACC of 9.82 per cent. The WACC is greater than that proposed by TransGrid, which based its proposed WACC on the historical average of the cost of debt. The WACC determined by the AER reflects increased corporate debt costs associated with adverse developments in international financial markets.

Table 4 outlines the WACC parameter values for this draft decision. The AER will update the nominal risk-free rate and debt risk premium, based on the agreed averaging period, and the expected inflation rate at a time closer to its final decision.

Table 4: AER's conclusion on TransGrid's WACC parameters

Parameter	TransGrid's proposal	AER's conclusion
Risk-free rate (nominal)	5.70%	5.46%
Risk-free rate (real)[a]	3.10%	2.84%
Expected inflation rate	2.52%	2.55%[b]
Debt risk premium	1.75%	3.27%
Market risk premium	6.00%	6.00%
Gearing	60%	60%
Equity beta	1.00	1.00
Nominal pre-tax return on debt	7.45%	8.73%
Nominal post-tax return on equity	11.70%	11.46%
Nominal vanilla WACC	9.15%	9.82%

(a) The real risk-free rate was derived using the Fisher equation.
(b) Established using RBA forecasts and targets.

Forecast operating expenditure

TransGrid proposal

TransGrid's forecast opex for the next regulatory control period is $855 million ($2007–08). This is $172 million higher than its expected opex in the current regulatory control period. TransGrid identified the following significant cost drivers:

- growth in the asset base over the next regulatory control period
- forecast increases in the real cost of labour
- increases in the real costs of operating materials and expenses
- forecast demand growth requiring greater network support expenditure.

AER conclusion

The AER is not satisfied that TransGrid's proposed opex forecasts reasonably reflect the opex criteria as set out in the NER, taking into account the opex factors. Because of this the AER must not accept the forecast opex in TransGrid's revenue proposal.

On the basis of its analysis of TransGrid's proposed opex forecast and the advice of PB, the AER has applied a reduction of $90 million to TransGrid's proposed opex. This represents a reduction of around 11 per cent of TransGrid's proposed opex of $855 million and results in an amended forecast opex allowance of $765 million.[3] Table 5 shows the total opex allowance by expense category.

Table 5: AER's conclusion on TransGrid's opex forecast ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's proposed controllable opex	135.2	144.4	149.7	161.8	166.5	757.6
Debt raising costs	3.7	4.0	4.3	4.8	5.1	22.0
Equity raising costs	0.9	1.7	3.1	4.0	4.2	13.9
Network support costs	21.5	6.0	6.0	6.0	6.0	45.5
Self insurance[a]	3.2	3.2	3.2	3.2	3.2	15.9
TransGrid's total opex	164.5	159.2	166.3	179.8	185.0	854.8
AER's controllable opex	128.4	135.7	139.5	147.9	149.9	701.3
Debt raising costs	1.9	2.1	2.2	2.4	2.6	11.2
Equity raising costs	–	–	–	–	–	–
Network support costs	21.5	6.0	6.0	6.0	6.0	45.5
Self insurance	1.4	1.4	1.4	1.4	1.4	6.8
AER's total opex allowance	153.2	145.1	149.0	157.6	159.8	764.8

Note: Totals may not add up due to rounding.
The AER will update the opex model with the latest CPI data at the time of its final decision.
(a) TransGrid submitted an updated self insurance proposal on 5 August 2008.

[3] The forecast opex allowance is $805 million in 2008–09 dollar terms.

This allowance represents the AER's estimate of the total opex that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives. The AER is satisfied that the total forecast opex of $765 million over the next regulatory control period reasonably reflects the opex criteria, taking into account the opex factors.

Efficiency benefit sharing

TransGrid proposal

The ACCC's 2005 revenue cap decision for TransGrid provided that the efficiency carry forward mechanism (ECFM) set out in the ACCC's 2004 *Statement of principles for the regulation of electricity transmission revenues* will apply to TransGrid for the current regulatory control period.

TransGrid proposed a total opex efficiency carryover payment of $17 million ($nominal) from the operation of the ECFM.

TransGrid did not explicitly propose a method for adjusting forecast opex for the purposes of the efficiency benefit sharing scheme (EBSS) to account for any difference between forecast demand growth and actual demand growth during the next regulatory control period.

TransGrid did not propose any cost categories for exclusion from the operation of the EBSS in its revenue proposal.

AER conclusion

The AER determined a total opex efficiency allowance under the ECFM of $8.9 million ($2008–09) for TransGrid over the next regulatory control period.

The AER will apply the EBSS to TransGrid for the next regulatory control period. The EBSS shares between TNSPs and transmission network users the efficiency gains or losses derived from the difference between a TNSP's actual opex and the forecast opex for a regulatory control period.

In the event that actual demand growth is outside the range of scenarios modelled in the development of TransGrid's approved forecast capex, for the purposes of the EBSS, forecast opex will be adjusted using the models (opex and capex) used to develop TransGrid's approved forecast opex. The EBSS will therefore incorporate the impact of actual demand growth on the commissioning of new assets.

The AER has excluded the opex cost categories of debt raising costs, self insurance costs, insurance costs, superannuation costs and non-network alternatives from the operation of the EBSS for the next regulatory control period. These are in addition to the costs of pass through events which are explicitly excluded by the EBSS.

Depreciation

TransGrid proposal

TransGrid has assigned regulatory asset lives to its categories of assets that equate to the assets' expected economic or technical lives. It has applied a straight-line method to determine systematic allocation of depreciation that is constant across periods. TransGrid's proposed regulatory depreciation allowance has been calculated using the post-tax revenue model (PTRM) and is set out in table 6.

Table 6: TransGrid's proposed regulatory depreciation allowance ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Straight-line depreciation	186.3	201.2	205.7	235.0	259.7	1087.9
Less: inflation adjustment on RAB	106.8	119.3	131.0	150.5	163.7	671.3
Regulatory depreciation	79.6	81.9	74.7	84.5	96.0	416.7

TransGrid noted that the AER's PTRM guideline adopted the partially as-incurred (hybrid) approach to recognising capex. TransGrid's current revenue determination is based on recognition of capex on a full as-incurred approach. TransGrid stated that it had complied with the requirements of the AER's guideline and transitioned to the hybrid approach in the calculation of its depreciation for the next regulatory control period.

AER conclusion

The AER has assessed each of the proposed asset life inputs to the PTRM that are used to calculate the regulatory depreciation allowance in accordance the NER. The AER considers that TransGrid's proposed depreciation schedules do not comply with the NER requirements and therefore has recalculated the depreciation allowance for this draft decision. Specifically the AER has revised some of TransGrid's proposed asset lives to align the treatment of standard lives for replacement asset classes with augmentation asset classes. The AER also reviewed TransGrid's proposed method for transitioning to recognise its capex on a partially as-incurred approach and agrees that it has been implemented appropriately in the PTRM.

On the basis of the approved asset lives, opening RAB, forecast capex allowance and the transitional arrangement to recognise capex on a partially as-incurred approach, the AER has determined the allowance for regulatory depreciation over the next regulatory control period in accordance with the NER as set out in table 7.

Table 7: AER's conclusion on regulatory depreciation allowance ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Straight-line depreciation	179.9	193.1	195.5	218.4	240.7	1027.60
Less: inflation adjustment on RAB	108.0	120.5	130.9	144.9	158.0	662.3
Regulatory depreciation	71.9	72.6	64.6	73.5	82.7	365.3

Service target performance incentive

TransGrid proposal

TransGrid's proposed performance targets, caps, collars and weightings for each of the parameters that apply to it under the service component of the scheme are set out in table 8.

Table 8: TransGrid's proposed values and weightings

Parameter	Proposed Values			
	Collar	**Target**	**Cap**	**Weighting**
Transmission circuit availability (%)				*MAR (%)*
Transmission line availability	98.92	99.12	99.24	0.2
Transformer availability	97.29	98.58	98.85	0.15
Reactive plant availability	98.67	99.13	99.33	0.10
Loss of supply event frequency (no.)				*MAR (%)*
> 0.05 (x) system minutes	7	4	2	0.25
> 0.25 (y) system minutes	2	1	0	0.1
Average outage duration (minutes)				*MAR (%)*
Total	917	790	663	0.2

Source: TransGrid, *Revenue proposal*, p.107.

TransGrid's proposal for the market impact component is based on the number of five minute dispatch intervals where an outage on its network results in a network outage constraint with a marginal value greater than $10/MWh. TransGrid's proposed market impact component parameter values and weighting are outlined in table 9.

Table 9: TransGrid's proposed market impact parameter values and weighting

Parameter	Proposed Values		
Market impact parameter	**Target**	**Cap**	**Weighting**
	Number of dispatch intervals with a marginal value greater than $10/MWh		*MAR (%)*
	2858[a]	0	2.0

Source: TransGrid, MITC performance data template, 9 June 2008.
(a) Note that the proposed performance target in TransGrid's revenue proposal at page 106 differs to the proposed performance target in the MITC performance data template that accompanied the revenue proposal. TransGrid confirmed that the proposed performance target in the MITC performance data template was the correct figure and should be taken as TransGrid's proposed performance target for the purpose of the AER's review.

AER conclusion

The AER has accepted some elements of TransGrid's service target performance incentive proposal, but, it has also made a number of adjustments. In summary, the AER:

- Accepts TransGrid's revised proposed performance targets for the transmission circuit availability parameters.
- Accepts TransGrid's proposed loss of supply event frequency parameter performance targets as they are based on the average performance of the most recent five years and meet the requirements of the scheme.
- Does not accept the average outage duration parameter performance target proposed in TransGrid's revenue proposal due to the discrepancies identified by PB and TransGrid and substitutes the performance target listed in table 10 for TransGrid's next regulatory control period.
- Accepts TransGrid's proposed methodology for setting the collar values for the transmission circuit availability and average outage duration parameters.
- Does not accept the transmission circuit availability parameters collar values proposed by TransGrid in its revenue proposal. The AER substitutes the collar values listed in table 10 for TransGrid's next regulatory control period.
- Accepts TransGrid's proposed collar values for the loss of supply event frequency parameters.
- Does not accept the collar values proposed by TransGrid in its revenue proposal for the average outage duration parameter. The performance target for the average outage duration parameter was revised during PB's review and as a result the collar values have also been revised. The AER substitutes the collar values listed in table 10 for TransGrid's next regulatory control period.
- Accepts the method proposed by TransGrid for calculating the cap values for transmission circuit availability parameters.
- Accepts TransGrid's revised proposed cap values for transmission circuit availability parameters. These cap values are listed in table 10.
- Accepts TransGrid's proposed cap values for loss of supply event frequency parameters. These cap values are listed in table 10.
- Accepts TransGrid's proposed methodology for calculating the cap for the average outage duration parameter.
- Does not accept TransGrid's proposed cap value for the average outage duration parameter and substitutes the cap value listed in table 10 for TransGrid's next regulatory control period. The proposed performance target value was changed due to the data discrepancies and therefore the cap values have also changed.
- Accepts TransGrid's proposed weightings as set out in table 10.

- Does not accept TransGrid's proposed performance target of 2858 dispatch intervals for the market impact component and substitutes a performance target of 2857 dispatch intervals to account for the five non–excluded degenerate solutions.

TransGrid's caps, collars, performance targets and weightings for the service component of the scheme during the next regulatory control period are set out in table 10.

Table 10: Service component caps, collars, targets and weightings to apply to TransGrid

Parameter	Collar	Target	Cap	Weighting
Transmission circuit availability (%)				*MAR (%)*
Transmission line availability	99.05	99.26	99.36	0.2
Transformer availability	97.26	98.55	98.84	0.15
Reactive plant availability	98.65	99.12	99.33	0.1
Loss of supply event frequency (no.)				*MAR (%)*
> 0.05 (x) system minutes	7	4	2	0.25
> 0.25 (y) system minutes	2	1	0	0.10
Average outage duration (minutes)				*MAR (%)*
Total	999	824	649	0.20

TransGrid's target and cap for the market impact component of the scheme are set out in table 11.

Table 11: Market impact component target, cap and weighting to apply to TransGrid

Parameter	Values		
Market impact parameter	**Target**	**Cap**	**Weighting**
	Number of dispatch intervals with a marginal value greater than $10/MWh		*MAR (%)*
	2857	0	2.0

Maximum allowed revenue

TransGrid proposal

TransGrid's maximum allowed revenue (MAR) for the final year of its current regulatory control period is $622 million ($2008–09). TransGrid has proposed a nominal smoothed MAR of $670 million in 2009–10, increasing to $921 million in 2013–14. TransGrid stated that its revenue proposal would result in an average annual increase in transmission charges of 3.9 per cent (real).

AER determination

The AER has determined an annual building block revenue requirement for TransGrid that increases from $678 million in 2009–10 to $904 million in 2013–14 ($nominal). The net present value (NPV) of the annual building block revenue requirement for the next regulatory control period has been calculated to be $2937 million. Based on this NPV amount, the AER has determined a nominal expected MAR (smoothed) for TransGrid that increases from $678 million in 2009–10 to $891 million in 2013–14, as shown in table 12. The total revenue cap for TransGrid over the next regulatory control period is $3909 million.

TransGrid's MAR for the next regulatory control period is established using a building block approach. When determining the expected MAR over the next regulatory control period, the AER has set the first year MAR equal to the annual building block revenue requirement for that year and applied an X factor of –4.39 per cent in subsequent years.

While the AER assesses TransGrid's proposed pricing methodology, actual transmission charges established at particular connection points are not approved by the AER. TransGrid establishes its transmission charges to recover its MAR, in accordance with its approved pricing methodology and the NER.

The effect of the AER's draft transmission determination on average transmission charges can be estimated by taking the annual MAR and dividing it by forecast annual energy delivered in New South Wales. Based on this approach, the AER estimates that this draft decision will result in a 6.6 per cent per annum (nominal) increase in average transmission charges from 2008–09 to 2013–14 or an increase of 4.0 per cent per annum in real terms ($2008–09).

Table 12: AER's draft decision on the maximum allowed revenue ($m, nominal)

	2009–10	20010–11	2011–12	2012–13	2013–14	Total
Return on capital	415.9	464.2	504.3	557.9	608.5	2550.8
Regulatory depreciation	71.9	72.6	64.6	73.5	82.7	365.3
Opex allowance	168.1	162.2	171.7	182.5	184.1	868.5
Opex efficiency allowance[a]	4.5	3.2	4.1	1.0	–3.9	8.9
Net tax allowance	22.5	23.7	23.0	26.0	29.0	124.4
Annual building block revenue requirement (unsmoothed)	678.4	722.7	763.6	840.0	904.3	3909.0
MAR (smoothed)	678.4	726.3	777.5	832.4	891.1	3905.7
X factor (%)	n/a[b]	–4.39	–4.39	–4.39	–4.39	n/a

(a) An allowance for opex efficiency resulting from the carry forward mechanism applied in the current regulatory control period.

(b) The MAR for 2009–10 is set as $678.4 million and TransGrid is not required to apply an X factor. The MAR in the first year of the next regulatory control period (2009–10) is around 9.1 per cent higher than the MAR in the final year of the current regulatory control period (2008–09).

Negotiating framework for negotiated transmission services

TransGrid proposal

TransGrid stated that its proposed negotiating framework is in accordance with the NER and sets outs the procedure to be followed when negotiating terms and conditions of access for a negotiated transmission service.

AER determination

The AER has assessed TransGrid's negotiating framework and considers that the negotiating framework in appendix G complies with the NER.

The AER has approved TransGrid's negotiating framework for the next regulatory control period.

Negotiated transmission service criteria

AER determination

The AER is required to make a determination specifying the negotiated transmission service criteria (criteria) that apply to a TNSP as part of its transmission determination for that TNSP.

In accordance with the NER, the AER published its proposed criteria for TransGrid in June 2008.

The determination by the AER in appendix H specifies the negotiated transmission service criteria for TransGrid over the next regulatory control period.

Pricing methodology

TransGrid proposal

TransGrid stated that its proposed pricing methodology complies with the requirements of chapter 6A of the NER and the guidelines.

AER determination

The AER has assessed TransGrid's proposed pricing methodology against part J of the NER and the pricing methodology guidelines. Based on its assessment, the AER has decided not to approve TransGrid's proposed pricing methodology.

The NER requires that if the AER refuses to approve any aspect of a proposed pricing methodology, the AER's draft decision must include details of the changes required or the matters to be addressed before the AER will approve the proposed methodology. The matters TransGrid must address in its revised pricing methodology are:

1. TransGrid is required to propose an alternative locational pricing structure which is consistent with clause 6A.23.4(e) of the NER and does not include a measure of energy.

2. Include the additional details on its approach to allocating costs to assets that provide both prescribed entry and prescribed exit services.

TransGrid must, not more than 30 business days after the publication of this draft transmission determination, submit a revised pricing methodology to the AER.

1 Introduction

1.1 Background

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

The AER makes determinations according to chapter 6A of the NER in respect of certain services provided by transmission businesses. In performing these obligations, the AER is responsible for regulating:

- the revenues that TNSPs may earn from providing prescribed transmission services
- the terms and conditions of access and the access charges to be applied by TNSPs for providing negotiated transmission services.

The AER is required to provide TransGrid an opportunity to recover sufficient revenues to meet the efficient costs of maintaining its network.

On 31 May 2008 TransGrid submitted to the AER its revenue proposal, proposed negotiating framework and proposed pricing methodology for 1 July 2009 to 30 June 2014 (the next regulatory control period). On 26 June 2008 the AER published these and its proposed negotiated transmission service criteria for TransGrid.

The Australian Competition and Consumer Commission (ACCC) determined TransGrid's current revenue cap for a five year period from 1 July 2004 to 30 June 2009 (the current regulatory control period)[4] under the National Electricity Code, which has been superseded by the NER.

1.2 Regulatory requirements

1.2.1 National Electricity Law

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

The national electricity objective is:

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

[4] ACCC, *NSW and ACT transmission network revenue cap 2004–05 to 2008–09, Final decision*, 27 April 2005. This revenue cap was revoked and substituted by the AER in February 2007.

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

- informed of material issues under the AER's consideration
- given a reasonable opportunity to make submissions in respect of that determination before it is made.[5]

The NEL also specifies that in making a transmission determination, the AER must, under the NER:

- provide the regulated transmission system operator with a reasonable opportunity to recover the efficient costs of complying with a regulatory obligation
- provide the regulated transmission system operator with effective incentives to promote economic efficiency in providing the services subject to the determination
- make allowance for the value of regulated assets and the value of any proposed new assets.[6]

In addition, the AER must have regard to any valuation of assets forming part of the transmission system owned, controlled or operated by the regulated transmission service operator applied in any relevant determination or decision.

1.2.2 National Electricity Rules

Chapter 6A of the NER sets out provisions the AER must apply in exercising its regulatory functions and powers for electricity transmission networks for prescribed transmission services and negotiated transmission services. In particular, the AER must make a transmission determination for a TNSP that includes a:

- revenue determination for the TNSP in respect of prescribed transmission services
- determination relating to the TNSP's negotiating framework
- determination specifying the negotiated transmission service criteria that apply to the TNSP
- determination specifying the pricing methodology to apply to the TNSP.[7]

The NER requires the AER to publish several transmission guidelines:

- the post-tax revenue model released in September 2007
- the roll forward model released in September 2007
- the efficiency benefit sharing scheme released in September 2007

5 NEL, section 16(1)(b).
6 NEL, section 7A.
7 NER, clause 6A.2.2.

- the service target performance incentive scheme released in August 2007
- the submission guidelines released in September 2007
- the cost allocation guidelines released in September 2007
- the pricing methodology guidelines released in October 2007.

These guidelines apply to TransGrid for the purposes of the AER making a transmission determination for TransGrid's next regulatory control period.

1.2.3 Revenue determination

Under clause 6A.4.2 of the NER the AER must use the building block approach to set a CPI – X revenue cap for a TNSP. The revenue cap is to meet the efficient cost of providing regulated transmission services. A revenue determination for a TNSP is to specify, for a regulatory control period of not less than five years, the following matters:

- the amount of the estimated total revenue cap for the regulatory control period or the method of calculating that amount
- the annual building block revenue requirement for each year of the regulatory control period
- the amount of the maximum allowed revenue for each year of the regulatory control period or the method of calculating that amount
- appropriate methodologies for the indexation of the regulated asset base
- the values that are to be attributed to the performance incentive scheme parameters for the purposes of the application to the provider of any service target performance incentive scheme applying for the regulatory control period
- the values that are to be attributed to the efficiency benefit sharing scheme parameters for the purposes of the application to the provider of any efficiency benefit sharing scheme applying for the regulatory control period
- the commencement and length of the regulatory control period.[8]

1.2.4 Negotiating framework for negotiated transmission services

Clause 6A.9 of the NER sets out the arrangements for negotiated transmission services. These services are separate from prescribed transmission services. Each TNSP must prepare a negotiating framework setting out the procedures to be followed by the TNSP and service applicants when negotiating for the provision of negotiated transmission services.

The AER's determination on the negotiating framework must set out requirements that are to be complied with for the preparation, replacement, application or operation of the TNSP's negotiating framework.

[8] NER, clause 6A.4.2(a).

1.2.5 Negotiated transmission service criteria

The negotiated transmission service criteria must give effect to and be consistent with the negotiated transmission service principles set out in clause 6A.9.1 of the NER.

Under clause 6A.9.4 of the NER the AER's determination on the negotiated transmission service criteria must set out the criteria that the TNSP must apply in negotiating:

- the terms and conditions of access for negotiated transmission services, including the prices that are to be charged
- any access charges which are negotiated by the provider during that regulatory control period
- the negotiated transmission service criteria also must include criteria, which a commercial arbitrator will apply to resolve disputes, regarding:
    - the terms and conditions of access for the negotiated transmission service, including the price that is to be charged for the provision of that service by the TNSP
    - any access charges that are to be paid to, or by, the TNSP.

1.2.6 Pricing methodology

Under clause 6.A.14.3(g) of the NER the AER is responsible for approving the pricing methodologies of TNSPs. A TNSP's pricing methodology sets out its approach to determining charges for prescribed transmission services in the next regulatory control period.

The NER requires a TNSP to submit a proposed pricing methodology for prescribed transmission services to the AER 13 months prior to the end of its current regulatory control period. The AER will assess the proposed pricing methodology against the pricing principles for prescribed transmission services in clause 6A.23 and the AER's pricing methodology guidelines.

1.3 Transitional arrangements

In 2005 the Commonwealth, state and territory governments agreed to review arrangements for the economic regulation of the energy sector, including the economic regulation of electricity transmission services. These arrangements established the AEMC as the NEM's rule-making body.

The AEMC commenced a review of the rules for regulating electricity transmission networks in the NEM in mid–2005. The new chapter 6A of the NER was released in November 2006. Appendix A provides a summary of the relevant transitional arrangements applicable to TransGrid.

1.4 Review process

The AER has assessed TransGrid's revenue proposal, proposed negotiating framework and proposed pricing methodology in accordance with the review process outlined in part E of chapter 6A of the NER. To date, this process has involved:

- Pre-consultation—TransGrid and the AER agreed on the provision of supporting information and documents by TransGrid as part of the review process.
- Proposal—TransGrid submitted its revenue proposal, proposed negotiating framework and proposed pricing methodology to the AER on 31 May 2008, 13 months prior to the end of its current regulatory control period. The AER assessed TransGrid's proposal against chapter 6A of the NER and the AER transmission guidelines.
- Public consultation—the AER published TransGrid's proposal and the AER's proposed negotiated transmission service criteria for TransGrid on 26 June 2008 and called for interested parties to make submissions. The AER held a public forum on TransGrid's proposal on 30 July 2008, where TransGrid made a presentation and interested parties asked questions of TransGrid.
- Submissions—the AER received 4 submissions on TransGrid's proposal. These were from the Energy Market Reform Forum, the Energy Users Association of Australia, Norske Skog and Snowy Hydro Limited.
- Assessment by a technical expert—The AER engaged Parsons Brinckerhoff Australia Pty Ltd (PB) as a technical expert to advise it on a number of key aspects of TransGrid's revenue proposal. Specifically, the AER asked PB to provide its opinion on:
  - whether the investment processes and procedures adopted by TransGrid for capital expenditure (capex) are likely to result in efficient outcomes
  - the adequacy, efficiency and appropriateness of the capex projects planned by TransGrid to meet its present and future service requirements
  - the effectiveness of TransGrid's operating practices and procedures and asset management system
  - the appropriateness of TransGrid's methodology to forecast its operating and maintenance expenditure (opex) requirements
  - the efficiency of TransGrid's forecast opex
  - the appropriate performance incentive scheme for service standards.

  PB has provided its opinion to the AER on these matters. PB's advice represents its independent views based on its review. The AER has considered this advice in making its draft decision. The terms of reference guiding PB's review are set out in appendix A of its report.

- Additional technical/specialist advice—The AER engaged Nuttall Consulting to provide it with technical and engineering advice throughout the review process. The AER engaged McLennan Magasanik Associates (MMA) to undertake a desk top review of the methods and processes used by TransGrid to develop its demand forecasts. The AER also engaged Econtech to provide a forecast of New South Wales labour cost growth.

1.5 Structure of draft decision

The AER's consideration of TransGrid's revenue proposal, proposed negotiating framework and proposed pricing methodology, together with the negotiated transmission service criteria to apply to TransGrid, are set out as follows:

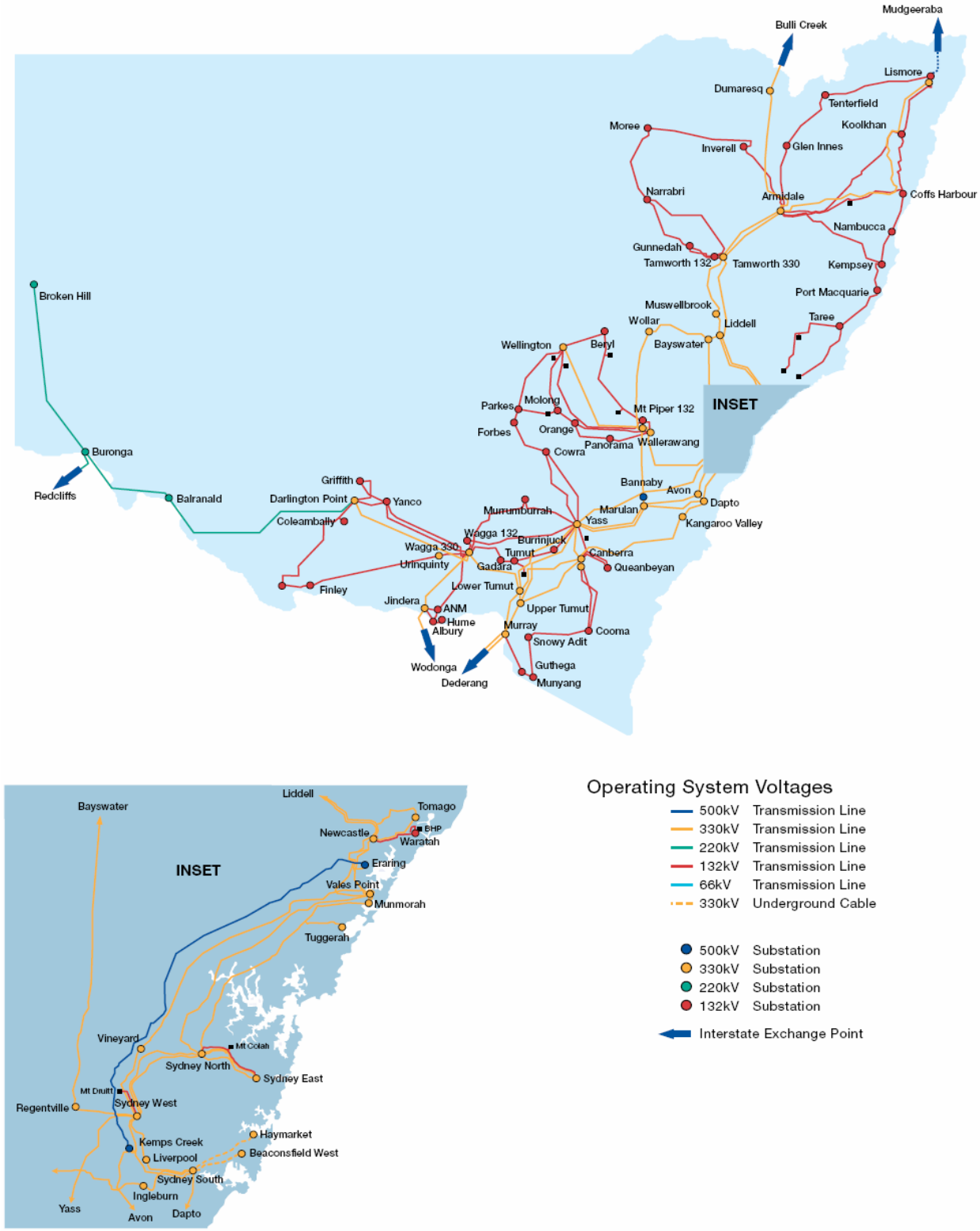
- chapters 2 to 7 sets out the AER's analysis and decisions regarding the proposed building block components
- chapter 8 specifies the performance values for each of the parameters applying under the service target performance incentive scheme
- chapter 9 determines the maximum allowed revenue for the next regulatory control period
- chapter 10 assesses the negotiating framework for negotiated transmission services
- chapter 11 discusses the negotiated transmission service criteria
- chapter 12 assesses the pricing methodology.

1.6 The TransGrid network

TransGrid's transmission network stretches along the east coast of Australia from the Queensland to Victoria borders, then inland to Broken Hill. Figure 1.1 illustrates TransGrid's network and highlights the substations near major load centres and transmission lines in NSW. It connects major generation sources in the Central Coast, Hunter Valley, Lithgow area and Snowy Mountains, and is interconnected with the Victorian and Queensland networks. TransGrid's network also connects to another transmission business, four distribution businesses and three directly connected industrial customers.

TransGrid operates 12 489 circuit km of transmission lines and cables, with nominal voltages of 500 kV, 330 kV, 220 kV, 132 kV and 66 kV. Further, it operates and maintains 83 substations which include 202 transformers comprising of 32 970 MVA of installed capacity throughout NSW.

Figure 1.1: Map of TransGrid's transmission network



Source: TransGrid, *Revenue proposal 1 July 2009 – 30 June 2014*, 31 May 2008, p. 13.

2 Opening asset base

2.1 Introduction

This chapter sets out the methodology that has been used by the AER to determine TransGrid's closing regulatory asset base (RAB) for the current regulatory control period. The closing RAB becomes the opening RAB for the next regulatory control period and is used to calculate TransGrid's maximum allowed revenue (MAR).

2.2 Regulatory requirements

2.2.1 NER requirements

Clause 6A.6.1 and schedule 6A.2 of the NER outline the approach that is used to determine the opening RAB.

Schedule 6A.2.1(c) of the NER provides that the RAB for the first year of the regulatory control period must be determined by rolling forward the RAB value set out in the schedule. For TransGrid this value is $3013 million (as at 1 July 2004). This value is adjusted to allow for the difference between estimated capex and actual capex in the previous regulatory control period. Schedule 6A.2.1(f) of the NER outlines how this value is further adjusted to roll forward and calculate the value of the RAB at the beginning of the first year of the next regulatory control period.

Clause 11.6.9 of the transitional provisions of the NER provides that the value of the RAB for the first regulatory control period under the revised NER (chapter 6A) may also be adjusted to have regard for an existing revenue determination and any other arrangements agreed between the AER and TNSP. The 2005 TransGrid revenue cap decision was made by the ACCC based on the framework contained in its *Statement of regulatory principles for the regulation of transmission revenues* (SRP).[9] Accordingly, the AER will roll forward TransGrid's RAB consistent with the SRP.

2.2.2 Statement of regulatory principles

TransGrid's 2005 revenue cap decision was made in accordance with the SRP. The capex included in that revenue cap decision was a forecast based on an assessment of the likely investment required over the current regulatory control period.

The SRP requires the closing RAB to be determined by reference to the depreciated (actual) value of the actual investment undertaken during the current regulatory control period, regardless of whether this closing RAB is larger or smaller than the closing RAB calculated on the basis of the forecast investment allowance. The effect of this arrangement is that if a TNSP spends less than its forecast capex during the regulatory control period, it retains the benefit of that lower expenditure (both return on and of capital) until the end of the regulatory control period. Conversely, if it exceeds its forecast capex allowance during the regulatory control period it does not receive a return on and of capital for that expenditure until the next regulatory control period.

[9] ACCC, *TransGrid final decision*, p. 10.

In September 2007 the AER published its asset base roll forward model (RFM) and guideline based on the requirements of the NER. The capex incentive framework in the NER is consistent with the arrangements under the SRP.

2.3 TransGrid proposal

TransGrid has proposed an opening RAB for the next regulatory control period of $4237 million as at 1 July 2009. The proposed opening RAB includes a higher than forecast past capex amount of $1428 million at the end of the current regulatory control period.[10]

TransGrid has used the AER's RFM to determine its proposed opening RAB. In performing the roll forward of its RAB, TransGrid has reduced its RAB by the disposal book value of assets shed during the current regulatory control period and adjusted its RAB for actual inflation using CPI.[11]

TransGrid has also decreased its opening RAB value by $14 million to account for lower than estimated capex between July 2003 and June 2004 in the previous regulatory control period. Further, it has removed the return on this amount over the current regulatory control period ($7.9 million) to establish the opening RAB as at 1 July 2009.[12]

2.4 Issues and AER considerations

2.4.1 Opening RAB—1 July 2004

Schedule 6A.2.1(c)(1) of the NER states that TransGrid's opening RAB (as at 1 July 2004) must be rolled forward to determine the opening RAB as at 1 July 2009, subject to schedule 6A.2.1(c)(2) and any applicable transitional provisions.

The timing of a revenue cap decision requires that a revenue cap for a future regulatory control period must be set before the end of the current regulatory control period. This means the actual capex for the final year of the current regulatory control period is not known before the closing RAB is established. This, in turn, means that TransGrid's opening RAB value of $3013 million, prescribed in schedule 6A.2.1(c)(1)—which was taken from the 2005 ACCC revenue cap decision—is based on estimates of capex in the later part of the previous regulatory control period.

Schedule 6A.2.1(c)(2) is designed to deal with this situation. It provides that, once the actual capex for the final part of the previous regulatory control period (in the case of TransGrid, this is the period from 1 July 2003 to 30 June 2004) is known, the opening RAB at 1 July 2004 must be adjusted for the difference between the forecast and actual expenditure.

---

10 TransGrid, *Meeting customer needs for transmission services, TransGrid revenue proposal, 1 July 2009 – 30 June 2014*, 31 May 2008, p. 109.

11 The CPI is based on the weighted average of eight capital cities published by the Australian Bureau of Statistics and calculated consistent with the method used for the indexation of the maximum allowed revenue during the current regulatory control period.

12 TransGrid, *Revenue proposal*, p. 109.

The AER's RFM makes the adjustments to the opening RAB as required under schedule 6A.2.1(c)(2).

TransGrid proposal

Chapter 6A of the NER prescribes the opening RAB value for TransGrid as $3013 million as at 1 July 2004.[13] TransGrid has used the AER's RFM and has adjusted the opening RAB for differences between actual and forecast capex during July 2003 to June 2004. In this period, TransGrid stated that actual expenditure was $14 million lower than forecast. The resulting excess return on the difference between actual and forecast capex to be removed from the RAB at 1 July 2009 is $7.9 million.[14]

AER considerations

The AER notes the NER requires that:

- the opening RAB for TransGrid is to be determined by rolling forward the value given to the RAB at a date specified in the table in schedule 6A.2.1(c)(1)
- the value of $3013 million prescribed in the table is to be adjusted for the difference between actual and forecast capex for any part of a previous regulatory control period
- this adjustment must remove any benefit or penalty on the returns associated with any difference between actual and forecast capex.

The AER reviewed inputs to the RFM for the previous regulatory control period—1 July 2003 to 30 June 2004—and is satisfied with TransGrid's proposed adjustments to the opening RAB for the current regulatory control period. In accordance with schedule 6A2.1(c)(2), the AER accepts the adjustments to TransGrid's RAB of $14 million for the difference between actual and forecast capex, and $7.9 million associated with the foregone return on that difference.

Table 2.1 shows the annual accumulated excess return on capital associated with lower than forecast capex from July 2003 to June 2004.

Table 2.1: Return on capex difference from July 2003 to June 2004 ($m, nominal)

	2004–05	2005–06	2006–07	2007–08	2008–09[a]	Total
Return on capex difference for 2003–04	–1.2	–1.4	–1.5	–1.9	–1.8	–7.9

Note: Total may not add up due to rounding.
(a) Based on forecast inflation rate which will be updated for actual CPI at the time of the AER final decision.

2.4.2 Roll forward methodology

Under the AER's RFM and based on the NER requirements, the closing RAB (nominal) for each year of the current regulatory control period is calculated by:

13 NER, clause S6A.2.1(c)(1).
14 TransGrid, *Revenue proposal*, p. 109.

1. increasing the opening RAB by the amount of capex incurred (including estimated capex for the remaining part of the current regulatory control period) and adjusted for the difference between actual CPI and forecast inflation
2. reducing the opening RAB by the amount of regulatory depreciation using the rates and methodologies allowed in the 2005 ACCC revenue cap decision, and adjusted for the difference between actual CPI and forecast inflation[15]
3. reducing the opening RAB by the amount of disposal value of any disposed assets.

At the end of the current regulatory control period, as discussed in section 2.4.1, the closing RAB is adjusted for the difference between estimated capex during the previous regulatory control period and actual capex for that part of the period, and the return on the difference.

TransGrid proposal

Applying the AER's RFM TransGrid stated that its opening RAB as at 1 July 2009 is $4237 million.[16]

AER considerations

During the AER's review of the RFM, TransGrid advised the AER that it identified an indexation input error. The indexation error was corrected by TransGrid, resulting in a decrease to the opening RAB.[17] The AER also identified some inconsistencies with the allocation of capex amounts to a non-network asset class in the RFM. TransGrid acknowledged this error and provided updated amounts, which showed the reallocation of amounts from the non-network asset class to other network asset classes, resulting in an increase to the opening RAB.[18]

TransGrid advised that during the current regulatory control period it replaced some connection assets. These replacement assets were committed to be constructed after 9 February 2006 and under clause 11.6.11 they cannot be considered to provide prescribed transmission services, even though the assets they replaced provided prescribed transmission services. As a result, these replacement assets provide negotiated transmission services. Clause 6A.6.1 of the NER provides that the RAB is the value of the assets used to provide prescribed transmission services. Therefore, in accordance with schedule 6A.2.3 the AER has removed the amount of $8.1 million from the RAB to account for these replacement assets.[19]

TransGrid also provided its actual capex for 2007–08, which became available after it lodged its revenue proposal, and an update of the expected capex for 2008–09.[20]

---

15 Regulatory depreciation is calculated by determining the straight-line depreciation for the RAB less the CPI indexation adjustment on the opening RAB.
16 TransGrid, *Revenue proposal*, p. 109.
17 TransGrid, response to AER information request 54, confidential, 14 July 2008.
18 TransGrid, response to AER information request 252, confidential, 3 September 2008.
19 The AER notes that there is a rule change process being undertaken by the AEMC in respect of the treatment of, among other things, replacement connection assets under clause 11.6.11, which may affect the classification of these assets. A similar adjustment also has been made to the tax asset base for tax modelling purposes.
20 TransGrid, response to AER information request 289, confidential, 23 October 2008.

The AER reviewed the updated inputs and accepts that they are appropriate for the purposes of the RFM. The net impact of these four adjustments is a decrease of $3 million to TransGrid's proposed opening RAB. Accordingly, for this draft decision, the AER has determined that TransGrid's opening RAB is $4234 million for the next regulatory control period (as at 1 July 2009). This value is used as an input for the AER's post-tax revenue model for the purposes of determining TransGrid's MAR during the next regulatory control period.

2.5 AER conclusion

Consistent with the NER and the SRP, TransGrid has proposed to roll forward its RAB, established in the ACCC's 2005 revenue cap decision, to determine an opening RAB for the next regulatory control period. Applying the RFM, the AER has determined TransGrid's opening RAB to be $4234 million for the next regulatory control period (as at 1 July 2009).

The RAB roll forward calculations are set out in table 2.2. The AER will update the roll forward of TransGrid's RAB with the most recent forecast of capex for 2008–09 and the latest actual CPI data, at a time closer to its final transmission determination.

Table 2.2: TransGrid's opening RAB for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	3012.8	3103.9	3228.8	3397.9	3737.0
Actual net capex (adjusted for actual CPI and WACC)[c]	134.0	154.1	221.2	333.4	577.3
CPI adjustment on opening RAB	71.1	92.6	78.6	144.1	104.6
Straight-line depreciation (adjusted for actual CPI)	–113.9	–121.7	–130.8	–138.4	–155.5
Closing RAB	3103.9	3228.8	3397.9	3737.0	4263.5
Less: difference between actual and forecast capex for 2003–04					13.5
Less: return on difference[d]					7.9
Less: connection assets providing negotiated transmission services					8.1
Opening RAB at 1 July 2009					4234.0

(a) Updated for actual 2007–08 capex.
(b) Based on estimated net capex and forecast inflation rate. The forecast inflation rate will be updated for actual CPI at the time of the AER final decision.
(c) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The accounting book values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $13.6 million for 1 July 2003 to 30 June 2004.

3 Forecast capital expenditure

3.1 Introduction

This chapter sets out the AER's conclusion on TransGrid's forecast capex allowance for the next regulatory control period. The AER has assessed TransGrid's capex proposal by examining whether:

- its governance framework, capex policies and procedures facilitate efficient investment outcomes
- the methods used to develop the capex proposal, including probabilistic planning, demand forecasts and network planning criteria, are robust and appropriate
- there is a genuine need for the projects proposed in the revenue proposal and whether the scope, timing and costs are efficient
- the cost accumulation process employed by TransGrid was reasonable
- TransGrid's contingent projects satisfy the NER requirements and should be treated as contingent projects
- the capex program is deliverable.

3.2 Regulatory requirements

3.2.1 Capex objectives

Clause 6A.6.7(a) of the NER provides that a TNSP must include the total forecast capex for the regulatory control period in order to achieve the capex objectives, which are to:

> (1) meet the expected demand for prescribed transmission services over that period;
>
> (2) comply with all applicable regulatory obligations associated with the provision of prescribed transmission services;
>
> (3) maintain the quality, reliability and security of supply of prescribed transmission services; and
>
> (4) maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

3.2.2 Capex criteria and factors

Clause 6A.6.7(c) also provides that the AER must accept the capex forecast included in a revenue proposal if it is satisfied that the total of the forecast for the regulatory control period reasonably reflects the capex criteria, which are:

> (1) the efficient costs of achieving the capital expenditure objectives
>
> (2) the costs that a prudent operator in the circumstances of the relevant TNSP would require to achieve the capital expenditure objectives; and

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

In making this assessment the AER must have regard to the following capex factors (clause 6A.6.7(e)):

(1) the information included in or accompanying the Revenue Proposal;

(2) submissions received in the course of consulting on the Revenue Proposal;

(3) such analysis as is undertaken by or for the AER and is published prior to or as part of the draft decision of the AER on the Revenue Proposal under rule 6A.12 or the final decision of the AER on the Revenue Proposal under rule 6A.13 (as the case may be);

(4) benchmark capital expenditure that would be incurred by an efficient TNSP over the regulatory control period;

(5) the actual and expected capital expenditure of the TNSP during any preceding regulatory control periods;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and capital expenditure;

(8) whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period;

(9) the extent to which the forecast of required capital expenditure of the TNSP is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms; and

(10) whether the forecast of required capital expenditure includes amounts relating to a project that should more appropriately be included as a contingent project under clause 6A.8.1(b).

Clause 6A.6.7(d) states that, if the AER is not satisfied that a TNSP's forecast capex reasonably reflects the capex criteria, then the AER must not accept the forecast capex in a revenue proposal. If the AER does not accept the total forecast capex proposed by a TNSP, clause 6A.14.1(2)(ii) of the NER requires the AER to include in its draft decision:

> … an estimate of the total of the Transmission Network Service Provider's required capital expenditure for the regulatory control period that the AER is satisfied reasonably reflects the capital expenditure criteria, taking into account the capital expenditure factors.

The AER is also required to assess contingent projects in accordance with clause 6A.8.1 of the NER. This clause requires details of proposed contingent capital expenditure to be provided to the AER and the identification of the trigger event needed to justify the proposed contingent project.

3.3 TransGrid proposal

TransGrid's revenue proposal, submitted in May 2008, contained a forecast capex allowance based on the demand forecasts from its 2007 Annual Planning Report (APR). It proposed a capex allowance of $2.6 billion ($2007–08) for the next regulatory control period and included 18 contingent projects.[21] The indicative costs for those projects ranged from $35 million to $650 million, and totalled $2.3 billion.[22] TransGrid noted in this proposal that following the publication of the 2008 APR there was scope for its proposed capex allowance to change and it would advise the AER if this situation arose.

During subsequent consultation with the AER, TransGrid advised that the 2008 APR, as well as potential policy developments arising out of the Garnaut review, would affect its proposed capex allowance. On 22 August 2008, TransGrid submitted an updated capex proposal reflecting its further consideration of various policy developments. TransGrid also used this opportunity to address a number of minor issues arising from the regulatory review process to that date. TransGrid proposed an updated capex allowance of $2.5 billion ($2007–08) for the next regulatory control period.[23]

The initial and updated proposals are discussed in more detail below. In brief, the 2008 APR forecast a slowing in peak demand with respect to that in the 2007 APR. Details on the changes between TransGrid's demand forecasts from the 2007 APR to the 2008 APR are contained in section 3.6.4.

3.3.1 Initial capex proposal

TransGrid's initial proposed capex allowance totalled $2627 million ($2007–08) for the next regulatory control period. Table 3.1 sets out the annual profile of TransGrid's initial capex proposal.

Table 3.1: TransGrid's proposed capex allowance ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Initial capex proposal	536.8	495.9	748.0	523.8	322.3	2626.8

Source: TransGrid, *Revenue proposal*, p. 73.

This information (as well as the capex in the current regulatory control period) is illustrated in figure 3.1. Table 3.2 sets out TransGrid's initial proposal by capex categories.

[21] TransGrid, *Revenue proposal*, p. 73.
[22] TransGrid, *Revenue proposal*, appendix I.
[23] TransGrid, letter to the AER, 22 August 2008.

Figure 3.1: TransGrid's initial proposed capex allowance ($m, 2007–08)

Source: TransGrid, *Revenue proposal*, p. 73, ABS Cat No: 6401.0, Consumer Price Index, Australia.

Table 3.2: TransGrid's initial capex proposal by category ($m, 2007–08)

Type	Investment category	Forecast capex	Percentage of total capex (%)
Load driven	Augmentation	1663.5	63.3
	Connection	0.0	0.0
	Land/easements	287.4	10.9
Non-load driven	Replacement	493.4	18.8
	Security/compliance	26.1	1.0
	Other Network	0.0	0.0
	Total network	2470.4	94.0
Non-network	Business IT	95.9	3.7
	Buildings/facilities	14.7	0.6
	Motor vehicle and Mobile plant	39.1	1.5
	Other	6.6	0.3
	Total non-network	156.3	6.0
Total capex		2626.7	100.0

Source: TransGrid, *Revenue proposal*, p. 73.
Note: Total may not add up due to rounding.

TransGrid's initial capex proposal was significantly higher in real terms (88 per cent) than the capex expected to be incurred during the current regulatory control period. TransGrid noted significantly higher capital investment is required due to its network facing a number of network constraints that require capital intensive solutions. TransGrid stated some of the drivers of its initial capex proposal included:[24]

- the age profile of its infrastructure
- planning obligations—in particular, the NSW requirement for DNSPs to plan to 'n−1' for all loads greater then 15MVA means TransGrid's network needs to be similarly planned
- several large augmentation projects required to meet the growing demand for electricity within its geographic market.

TransGrid noted the cost of meeting its capex program was also increasing due to:[25]

- the rising price of electricity transmission equipment
- rising wages growth and increasing compliance requirements associated with community and environmental obligations.

Load driven network investment includes expenditure on augmentation and on strategic land and easements acquisitions. Non-load driven investment includes replacement expenditure on ageing assets, compliance with legal and regulatory obligations and ensuring the physical security of physical infrastructure. Over 90 per cent of TransGrid's initial forecast capex is due to augmentation, easements and replacement projects (see table 3.2).

TransGrid used a probabilistic assessment as part of its approach to forecast its initial load driven investment requirements for the next regulatory control period. The proposed load driven capex is dominated by three large projects (around 40 per cent of total capex) to reinforce supply to Sydney, Newcastle, Wollongong and the NSW north coast.[26]

TransGrid used an asset replacement strategy based on the assessment and monitoring of its assets. The issues considered in its assessments included condition of the assets, ongoing serviceability, NER requirements for reliability, comparison to practices used by other TNSPs, safety requirements and the environment in which it operates. It stated this information, together with identified priorities, determined asset replacement plans.[27]

TransGrid noted its IT capex requirements were identified on a rolling replacement program based on asset life.[28] Vehicles and mobile plant capex requirements were identified on a needs basis following assessment and consideration of (amongst other factors) age and reliability, legislative requirements, technology and OH&S

24 TransGrid, *Revenue proposal*, pp. 31, 54, 66.
25 TransGrid, *Revenue proposal*, p. 37.
26 TransGrid, *Revenue proposal*, p. Appendix H, pp. 1–32.
27 TransGrid, *Revenue proposal*, p. 64.
28 Asset life was determined by Gartner research and applied to the TransGrid environment.

requirements. Estimates for capex for buildings and facilities were identified on a needs basis and individually assessed. Other capex, including office equipment, was based on obsolescence or availability of manufacturer's support.[29]

TransGrid's initial revenue proposal also included 18 contingent projects (section 3.6.11). The indicative costs for these projects range from $35 million to $650 million, and total $2.3 billion. This total excluded a contingent project that had been identified but not costed (the system protection scheme).[30]

3.3.2 Updated capex proposal

On 22 August 2008, TransGrid provided the AER with an updated version of its capex proposal following the release of its 2008 APR. The revision included a reconsideration of key NSW development scenarios as well as minor amendments to address issues identified in consultation with the AER and PB.

TransGrid advised the revisions to its capex proposal arose principally from:[31]

- new information on economic assumptions provided by NEMMCO
- greater certainty associated with the Munmorah power station—the NSW Government had clarified its position and had committed to keeping the power station running until 2013, despite an earlier report (the Unsworth Report[32]) which had recommended its closure.

These revisions are reflected in the timing of expenditures (a shift to the end of the period) and result in a net decrease ($77 million) in TransGrid's total capex allowance for the next regulatory control period. The updated capex proposal of $2550 million is set out in table 3.3.

The key impacts of the release of the 2008 APR and its associated demand forecasts on TransGrid's proposed capex program include:

- several major projects being deferred by varying periods of times in each of the scenarios in the probabilistic modelling undertaken by ROAM (see section 3.6.3). Projects in this category include the Bannaby − South Creek 500kV transmission line, Holroyd − Chullora cables and substation, and the Kemps Creek − Liverpool 330kV transmission line
- removal of the Hunter Valley − Central Coast 500kV transmission line from the proposed capex program and its movement to contingent projects. Proposed contingent projects, however, remain around $2.3 billion with this change.

29 TransGrid, *Revenue proposal*, pp. 72–73.
30 TransGrid, *Revenue proposal*, Appendix I, pp. 1–10.
31 TransGrid, *Revenue proposal*, letter to the AER, 22 August 2008.
32 NSW Government, *Energy Consultative Reference Committee Impact Statement*, 7 March 2008.

Table 3.3: Difference in TransGrid's proposed capex allowances ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Initial capex proposal	536.8	495.9	748.0	523.8	322.3	2626.8
Updated capex proposal	531.9	465.9	579.2	552.3	420.6	2549.8
Difference	–4.9	–30.0	–168.8	28.5	98.3	–77.0

Sources: TransGrid, *Revenue proposal*, p.73;
TransGrid, *Updated revenue proposal*, Pro-forma statements.

TransGrid also reviewed the forecast costs for property and easement acquisitions. However, it determined, given the strategic importance of these assets, that no change in timing or estimates was required.[33]

Further information on how the 2008 APR impacted on the individual capex projects reviewed by PB is detailed in appendix B.

3.4 Submissions

The AER received submissions on TransGrid's capex proposal from:

- Energy Markets Reform Forum (EMRF)
- Snowy Hydro Limited
- Energy Users Associated of Australia (EUAA)
- Norske Skog.

The main issues raised in these submissions were:

- the robustness of the modelling undertaken, given the uncertainty associated with the carbon trading scheme, the credit crisis and economic conditions more broadly
- the deliverability of the proposed capex due to challenges associated with purchasing, installing and maintaining it
- the timing, scope for deferment and the robustness of the supporting evidence for the proposed capex.

Issues raised by stakeholders on specific aspects of TransGrid's proposal are discussed in section 3.6.

3.5 Consultant review

This section summarises the findings of PB with respect to TransGrid's capex proposal. PB's findings on specific aspects of the proposal are noted in section 3.6 and appendix B and C.

[33] TransGrid, letter to the AER, 22 August 2008.

The AER engaged PB to provide an independent assessment of the efficiency and appropriateness of TransGrid's capital governance framework and capex proposal. Specifically, PB was required to:

- review capex over the current regulatory control period and identify if there are any issues for TransGrid's proposed capex in the next regulatory control period
- review the capital governance framework, including capex strategies, policies and procedures
- assess the adequacy and appropriateness of TransGrid's probabilistic forecasting
- assess TransGrid's cost accumulation methodologies and outcomes, including unit cost estimates, real price escalators and contingency and other additional costs used
- undertake a detailed review of a suite of proposed network and non-network projects (nine network and two non-network projects were examined) against clause 6A.6.7 of the NER
- determine whether the forecast capex program is deliverable
- assess each proposed contingent project against clause 6A.8.1 and the capex objectives outlined in clause 6A.6.7 of the NER.

In the event that PB disagreed with TransGrid on individual project reviews it was required to:

- outline why the proposal was not in accordance with the NER
- provide an alternative capex cost estimate (or timing of the proposal) that it considered efficient, including a justification for the change that it considered would satisfy the NER.

As part of PB's assessment it evaluated the documentation in TransGrid's revenue proposal, sought additional information on specific projects and undertook follow-up discussions with TransGrid. The AER also allowed TransGrid an opportunity to respond to PB's draft report, and the information obtained from TransGrid's response was considered by PB in its final report. From its assessment PB found:[34]

- the capex development process is sound
- TransGrid's scenario planning and probabilistic methodology is robust and well supported
- TransGrid's proposed producers' margin escalator had not been reasonably determined
- TransGrid's proposed steel escalator included too much (relatively high cost) construction costs and too little (relatively low cost) steel costs

[34] PB, *TransGrid revenue reset: An independent review*, 12 November 2008, pp. 157−159.

- the five year aggregate weighting of escalator components is unreasonable
- TransGrid's proposed 'S-curves' are reasonable
- TransGrid's application of non-standard scoping factors in its capital expenditure estimating process is considered to be unreasonable
- the application of a risk allowance is appropriate, but overstated
- TransGrid's options analysis is limited and simplistic
- TransGrid has not defined a number of contingent project triggers in a specific manner that can be objectively verified
- TransGrid has a high probability of being able to deliver its updated forecast capex program.

Table 3.4 shows PB's recommended adjustments to TransGrid's initial forecast capex proposal and its recommended forecast capex allowance for the next regulatory control period.

Table 3.4: PB's recommended forecast capex allowance ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's initial proposal	536.8	495.9	748.0	523.8	322.3	2626.8
PB's proposed capex amendments	–4.4	–22.3	–34.3	–34.8	–32.6	–128.6
PB's recommended capex allowance	532.4	473.6	713.7	489.0	289.7	2498.2

Sources: TransGrid, *Revenue proposal*, p. 73; PB, p. 246.

PB considered TransGrid's capex allowance was likely to be prudent and efficient subject to its recommended reduction of $129 million. Based on its assessment, PB recommended a capex allowance of $2498 million (a 4.9 per cent reduction to TransGrid's initial proposal) and a provision for contingent projects of $1.2 billion based on indicative costs.[35]

3.5.1 Consultant supplementary review

PB also conducted a supplementary review focussing on the impact of the 2008 APR on TransGrid's revenue proposal and on PB's initial assessment.

The implications of the 2008 APR on TransGrid's capex proposal are discussed throughout this chapter, particularly sections 3.3.2 and 3.7. Table 3.5 compares TransGrid's initial and updated capex proposal with PB's initial and updated recommended capex allowance for each year of the next regulatory control period.

[35] PB, p. 246.

Table 3.5: Comparison of capex allowance ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's initial proposal	536.8	495.9	748.0	523.8	322.3	2626.8
PB's initial recommendations	532.4	473.6	713.7	489.0	289.7	2498.2
TransGrid's updated proposal	531.9	465.9	579.2	552. 3	420.6	2549.8
PB's updated recommendations	526.2	443.1	554.1	523.2	382.1	2428.7

Sources: TransGrid, *Revenue proposal*, p. 73; TransGrid, *Updated revenue proposal*, pro-forma statements;
PB, p. 246; PB, *TransGrid revenue reset: Supplementary review*, p. 30.

3.6 Issues and AER considerations

3.6.1 Historical capex

This section examines whether TransGrid's historical capex aligns with that provided under the current regulatory control period. This review was undertaken to indicate if there are any ongoing systematic issues that the AER needs to consider in relation to TransGrid's proposed forecast capex for the next regulatory control period. The AER considers such issues are relevant in determining whether it is satisfied TransGrid's proposed forecast capex reasonably reflects the capex criteria.

TransGrid proposal

TransGrid's expected capex for the current regulatory control period is 5 per cent more than the capex approved by the ACCC[36] in April 2005.[37] This overspend is, however, confined to the last year of the current regulatory control period. In the first four years of the current regulatory control period TransGrid under spent its capex allowance. TransGrid noted its capex will grow over the remainder of the period, given around 85 per cent of the contracts for 2008–09 projects are in place.[38]

Table 3.6 compares TransGrid's historical capex, as specified in its initial proposal, and the approved capex by expenditure type for the current regulatory control period.

[36] ACCC, *TransGrid final decision.*
[37] TransGrid, *Revenue proposal*, p. 44.
[38] TransGrid, *Revenue proposal*, p. 44.

Table 3.6: TransGrid's actual capex – 1 July 2004 to 30 June 2009 ($m, 2007–08)

Category	ACCC decision	TransGrid actual/forecast	Difference
Augmentation	828.0	758.0	–70.0
Replacement	314.6	395.8	81.2
Property and easement	99.9	138.2	38.3
Business support	94.4	102.3	7.9
Total	1337.0	1394.4	57.4

Source: TransGrid, *Revenue proposal*, p. 44.

In percentage terms augmentation expenditure was around 8 per cent below the ACCC's allowance due to the deferment of construction of the Wollar to Wellington transmission line and delays in obtaining regulatory and planning approvals for the installation of a second supply point for the ACT as part of the Williamsdale project.

Network replacement expenditure was more than 25 per cent above the allowance due to the replacement of a larger number of assets in poor condition. Property and easement expenditure was more than 38 per cent above the allowance due to a larger building and facilities construction program in the period.

The expenditure profile was also different to that forecast, with TransGrid spending later in the period. TransGrid noted this was due to delays in construction and not receiving the ACCC's final decision until one year into the current regulatory control period.

None of the five contingent projects approved by the ACCC were undertaken by TransGrid as the trigger events did not occur.

Submissions

The EUAA stated it was concerned with the difference between allowed and incurred expenses, and their implications for the regulatory asset base and prices. It noted TransGrid:[39]

- had under spent its capex allowance by more than $96 million in the three financial years commencing 2004–05
- expects to over spend its capex allowance by more than $188 million in the final year of the current regulatory control period
- expects to over spend its capex allowance by $57 million over the full five years of the current regulatory control period.

The EUAA also highlighted its concern that an ex ante regime may encourage 'gaming' as it provides for a TNSP to retain the benefits of a capex under spend, and

[39] EUAA, *Submission to AER review of TransGrid's revenue proposal for 2009/10 to 2013/14*, 15 August 2008, p. 10.

to derive deferred benefits of an over spend, to the extent that it is rolled into the asset base at the time of the next revenue reset. The EUAA noted that a pattern of under spend followed by over spend sets up what may be presented as a forward trend of increasing capex requirements beyond the current regulatory control period, with a possible aim of setting up the pre-conditions and arguments for a step wise increase in capex in the next regulatory control period.[40]

Consultant review

PB was required to undertake a high level review of TransGrid's capex in the current regulatory control period and identify if there were any issues that may be relevant for assessing the proposed capex for the next regulatory control period.

PB noted TransGrid had over spent its capex allowance by $57 million or 4.3 per cent in the current regulatory control period. It also noted TransGrid's program of works was under spent in all years up to 2008–09, where an over spend of 58 per cent is expected.[41]

Consistent with the high level scope of the review, PB focussed on understanding significant differences in expenditure relative to the original allowance to determine:

- how the drivers for such differences had been accounted for
- how those drivers may influence the capex proposed for the next regulatory control period.

PB's key findings were:[42]

- the over spend in land and easements was related to the expected compensation payments associated with strong market conditions in land in the immediate vicinity of proposed works and an increase in the overall capital works program
- the over spend in replacement capex was due to a number of factors, particularly, six unforeseen replacement projects with a value of $46 million
- 14 of the 19 'support for business' projects listed had changed materially from the original allowance, in terms of price input changes and/or change of scope. For example, a change in NSW occupational health and safety regulations resulted in an increase in the number of elevated work platforms required and each platform costs around $0.25 million.

PB's high level review of historical capex did not identify any systemic concerns that had to be addressed as part of TransGrid's proposed capex for the next regulatory control period.[43]

AER considerations

The AER notes the $46 million in unforeseen replacement capex that TransGrid attributed to the pattern and size of its capex program in the current regulatory control

40 EUAA, p. 3.
41 PB, pp. 73−74.
42 PB, pp. 79−83.
43 PB, pp. 79–83.

period. The AER also notes the EUAA's concerns regarding both the size of TransGrid's over spend and the scope for a TNSP to try 'gaming' the system by spending later in the regulatory control period.

The AER does not consider it unreasonable that some unidentified replacement projects may arise over the course of a regulatory control period. However, the timing and relative size of this unexpected replacement suggests, at first glance, there is scope for TransGrid to improve its awareness of the condition of its assets and its accompanying governance arrangements. The AER nonetheless considers that the EUAA's concerns are largely addressed by PB's finding that the difference between the capex allowed and that spent does not represent any specific expenditure drivers that have not been addressed by TransGrid in its capex proposal for the next regulatory control period. Further, the AER notes that TransGrid has taken substantial steps to improve its governance arrangements and that PB found TransGrid's overall governance framework has improved and is now in line with good industry practice (section 3.6.2).

The AER notes TransGrid's comment that the timing of the ACCC's 2005 revenue cap decision contributed to the delays in its capex program but questions whether that is a reasonable view. While recognising some of the complexities associated with the 2005 revenue cap decision, the AER considers a prudent operator in the circumstances of TransGrid could have made provisions for this, which would have allowed it to continue to plan and implement capex projects pending the outcome of the regulatory determination.

On balance, considering the information provided by TransGrid and PB's analysis, the AER is satisfied that TransGrid's capex in the current regulatory control period is reasonable for an operator in TransGrid's circumstances. The AER concludes there are no systemic issues that have been identified in the current regulatory control period that need attention in the next regulatory control period.

3.6.2 TransGrid governance framework, capex polices and procedures

This section examines whether TransGrid's capital governance arrangements and capex policies and procedures are appropriate, and provide a sound framework for undertaking investment aimed at achieving the capex objectives listed in clause 6A.6.7(a). This is an important consideration in determining whether the AER is satisfied that TransGrid's forecast capex proposal reasonably reflects the capex criteria and the capex objectives.

TransGrid proposal

TransGrid has developed policies and procedures that govern its investment decision making process. Key aspects of the policies and procedures identified by TransGrid include:[44]

- a review of the 'well-being' of the assets it manages. The output from this (replacement) review forms the input into the Network asset management plans, and by considering this against the augmentation capital works program (driven by growth) TransGrid determines what projects/programs should be pursued

[44] TransGrid, *Revenue proposal*, pp. 64, 75–79.

- for major capital projects (capital works projects with an expected expenditure greater than $1 million) there is a sequence of decision gates—project commencement and project funding approval—that must be passed. Review and status reporting for each major project must also be undertaken

- the governance framework is supported by a number of strategic asset management plans from which projects are identified and prioritised. TransGrid's strategic asset management plans include its:

  - Network asset management plan (five and 30 year horizons)

  - IT asset management plan

  - Fleet management plan.

  TransGrid also has a Strategic network development plan 2008 to inform itself on how the NSW transmission network is expected to develop over the next 25 years

- TransGrid has engaged major engineering companies for two to four years to provide specialist engineering advice on issues, including feasibility studies and project cost estimations to complement its own internal resources

- TransGrid continually tests the market and reassesses its sources of supply to facilitate best value for money for its projects.

Submissions

The EUAA noted the following concerns:[45]

- TransGrid had failed to demonstrate it had sufficiently considered non-network solutions when developing its capex program

- anticipatory capex had occurred in advance of successful completion of regulatory tests

- TransGrid had failed to supply sufficient supporting data and customers have been unable to fully validate its revenue proposal.

Consultant review

PB was engaged to assess whether TransGrid's capital governance framework was consistent with achieving efficient investment outcomes.

PB found, through a high level examination of its governance framework and through the review of sample capex projects, that TransGrid's:[46]

- governance of major projects is sound and it has sound processes in place, including documented procedures, responsibility, reporting and monitoring. Projects and non-network expenditure such as vehicles and IT systems also have appropriate plans and approval processes in place

[45] EUAA, pp. 3, 7−8.
[46] PB, pp. 42−43.

- planning and documentation processes appear to be well structured and integrated within the business. The planning process has well defined and appropriate review points that align with critical decisions

- asset management process is consistent with good industry practice and employs condition monitoring and condition based replacement triggers to maximise the life of assets

- planning is based on specific criteria that reflect its planning obligations under the NER and NSW jurisdictional requirements. The formal planning processes detailed by TransGrid also demonstrate a prudent approach to forward planning, structured primarily to meet its regulatory reporting requirements of forecasting future network constraints and the associated forward capex requirements

- scenario based planning, which is used to assess network capability under a number of NEM load/generation scenarios, represents good industry practice[47]

- accelerated capital works planning process, used for the purpose of preparing the forward capex program in its revenue proposal, is reasonable

- consultation process is structured to comply with its obligations under the NER—TransGrid has processes in place to ensure consultation with interested parties prior to it constructing significant network augmentation

- joint planning sessions, with major generators and the NSW DNSPs, are held largely on an as needed basis, but typically at least annually, and provide an opportunity to consult on capital projects that impact each of the parties. A joint demand forecasting meeting is also held with the NSW DNSPs on an annual basis.

However, PB considered that the following aspects of TransGrid's capital governance framework could be improved:

- in some cases, the approval process for IT projects had not been followed and, while there is no evidence of inappropriate investment, PB considered there is a risk that unnecessary expenditure could have been incurred or that lower cost alternatives may not have been considered[48]

- the lack of a clearly documented process that applies to the purchase of property, where the property is to be acquired prior to the project receiving formal justification has the potential to lead to inconsistent and inefficient site and easement expenditure[49]

- the use of risk assessments to inform asset refurbishment or replacement is not consistently applied in TransGrid's asset management process, as acceptable risk levels are not well defined. While risk assessment results are considered, asset

[47] Scenario based planning involves the development of a range of scenarios that are based on factors such as generation costs, government policy impacts, energy technology and energy development (see section 3.6.3).

[48] PB, p. 42.

[49] PB, p. 42.

management decisions are typically made based on 'engineering judgement' which remains a less transparent basis for investment decisions.[50]

While the addressing of these concerns could further improve TransGrid's governance arrangements, PB was satisfied that TransGrid's overall governance framework was in line with good industry practice.[51]

AER considerations

The AER has reviewed TransGrid's documentation and based on PB's analysis considers that TransGrid's capital governance framework is consistent with achieving efficient investment outcomes. In particular, the AER agrees with PB's findings that TransGrid's capital governance framework contains appropriate controls, checks, accountability, reviews and approvals gateways, and is consistent with good industry practice. However, the AER notes that while PB did not recommend any changes to TransGrid's forecast capex based on its examination of its governance framework, it did identify a number of areas where the application of its governance framework could be improved.

The AER recognises the EUAA's concern that TransGrid has failed to supply sufficient supporting data and that customers have been unable to fully validate its revenue proposal.[52] The AER notes that it has determined that TransGrid's revenue proposal meets the requirements of its submission guidelines[53] and therefore contains sufficient information. In addition, the AER recognises that TransGrid has established a process for consultation prior to it deciding to construct significant network augmentation and that process is structured to comply with NER obligations.[54] This provides the opportunity for further consultation and information exchange with stakeholders when projects are further developed. Importantly and finally, where clarification and/or additional information have been requested of TransGrid by the AER and PB, it was generally provided in a timely manner.

Based on PB's advice that TransGrid's capital governance framework is consistent with achieving efficient investment outcomes and its own consideration of the material presented by TransGrid, the AER considers TransGrid's capital governance framework is consistent with achieving efficient investment outcomes.

The AER also notes that TransGrid has adopted a new corporate governance framework for expenditure on major capital works contained in its capital program for 2004–09. This framework sets out a sequence of decision gates, in particular for project commencement and project funding approval, and subsequent status reporting for each major project.[55]

The AER also recognises that continuous improvement is an important aspect of any organisation and that while it is satisfied that TransGrid's capital governance framework is likely to result in efficient and prudent investment decisions, there is scope for further improvement. In particular, the AER considers that TransGrid's

50 PB, pp. 57−58.
51 PB, p. 42.
52 EUAA, pp. 3, 7−8.
53 AER, *Electricity transmission network service providers, Submission guidelines*, September 2007.
54 PB, *TransGrid revenue reset: An independent review*, p. 41.
55 TransGrid, *Revenue proposal,* p. 75.

incorporation of PB's suggested changes, including better adherence to IT purchasing protocols and improved/documented protocols regarding the early purchase of land, could result in improved governance and better implementation of its projects, thereby enhancing the efficiency of its investment decisions.

3.6.3 Probabilistic planning approach

This section discusses whether TransGrid's probabilistic planning approach, which it used to develop its forecast load driven capex profile, is a robust methodology and is likely to result in prudent and efficient investment decisions. The AER's consideration of this methodology assists it to be satisfied that the proposed forecast capex reasonably reflects the capex criteria.

TransGrid proposal

TransGrid used a probabilistic approach to develop its capex forecast to account for the uncertainty surrounding generation development in NSW over the next 10 years.[56] TransGrid engaged ROAM Consulting (ROAM) to produce development scenarios under a range of assumptions including those associated with inter-regional trade, water availability, interconnector capability and carbon values. These assumptions imply different outcomes in terms of load growth and flows of electricity in the NSW region, as well as the type and location of generation plant.

Seven elements made up ROAM's probabilistic planning approach:[57]

1. The identification of theme sets that will impact on the development of the energy sector in NSW. ROAM used information from TransGrid's 2007 APR and the 2007 NEMMCO Statement of Opportunities (and subsequent opportunities) documents in its analysis.
2. The development of 36 scenarios as set out in table 3.7. Each possible combination of four theme sets ($3 \times 3 \times 2 \times 2$) forms a scenario and determines the top down probability of that scenario eventuating.[58]
3. The identification of the scenario dependent generation developments (e.g. technology type, location, size and fuel type).
4. Analysis was undertaken to derive the weighting applicable to each generation project assumed to proceed within the given scenario. This was to account for the uncertainty relating to which of the various prospective generation developments will be developed under each particular theme. This was not captured in the top down probabilities.
5. The initial scenario probabilities were calculated from a combination of the top down and bottom up probabilities.
6. The initial scenario probabilities were moderated to account for the minimum reserve margin.[59]

---

56 TransGrid, *Revenue proposal*, pp. 59−60.

57 ROAM, *Scenarios for revenue reset application 2009–10 to 2013–14*, February 2008, pp. 2–17.

58 Scenario probability = (load growth probability) × (inter–regional trade probability) × (water availability) × (carbon probability).

59 The minimum reserve margin condition is defined as having sufficient plant to supply the peak 10 per cent of probability of exceedence demand, plus the assumed reserve margin.

7. For completeness, the final project probabilities are determined. This is undertaken to determine the probabilities of specific development occurring in NSW when some projects are not selected in some of the scenarios determined. The bulk of the selected projects that fit into this category were located in Central NSW, while a large proportion of the wind developments were located around Canberra and South Eastern NSW.

In determining the 36 future development scenarios TransGrid noted it amended the scenario probabilities and took a more conservative approach than that developed by ROAM. The adoption of such an approach resulted in the deferral of a number of projects and a reduction in capex estimates.[60] In developing possible solutions to the various scenarios TransGrid noted it considered non-network solutions to network constraints. Where TransGrid identified a non-network solution that could result in a more efficient outcome this was considered. However, TransGrid noted the cost of a non-network solution was difficult to quantify and consequently included a capital allowance for network solutions in its revenue proposal.

Table 3.7: ROAM's market development scenarios and associated probabilities

Theme	Scenario	Description	Probability
Load growth	Low	Low load growth, with the proceeding of Tallawara, Uranquinty and Lake Munmorah stations	15 %
	Medium	Medium load growth, with the proceeding of Tallawara, Uranquinty and Lake Munmorah stations	70 %
	High	High load growth, with the proceeding of Tallawara, Uranquinty and Lake Munmorah stations	15 %
Inter-regional trade	Neutral	'Business as usual' inter-regional trading	55 %
	QNI upgrade	Higher import and export capacity – an additional 500 MV	35 %
	NSW-SNOWY upgrade	Higher import and export capacity – an additional 500 MV	10 %
Water availability	Neutral	Water restrictions ease	35 %
	Limited	Water restrictions continue	65 %
Greenhouse policy	Neutral	'Business as usual' greenhouse policy	40 %
	CO_2 Tax	Implementation of an emissions trading scheme	60 %

Source: TransGrid, *Revenue proposal*, Appendix E, p. 4.

[60] TransGrid, *Revenue proposal,* p. 60.

Submissions

The EUAA noted:[61]

- the uncertainty associated with the carbon reduction scheme needed to be more accurately reflected in TransGrid's scenario modelling. In particular, it suggested additional modelling was required to account for the likely outcome of a soft and late start to the carbon reduction scheme[62]

- the uncertainty associated with the credit crisis and an economic slow down needed to be adequately considered in TransGrid's modelling

- TransGrid should have based its modelling on the 2008 APR and not the 2007 APR.

The EMRF highlighted robust risk analysis, including an assessment for delaying projects, should have been undertaken and that TransGrid's ability to implement its capex program could be hindered by supply constraints.[63]

Snowy Hydro Limited noted the importance of the Bannaby - Kemps Creek 500 kV project to supplying Sydney with electricity.[64]

Consultant review

PB reviewed the probabilistic planning approach used by TransGrid and found the:[65]

- scenario planning and probabilistic methodology is sound and represents a robust process that is well documented and evidenced

- development of the scenario probabilities is well considered and the final scenario probabilities are realistic.

PB also noted ROAM's updated scenario analysis has minimal impact on TransGrid's capex program as:[66]

- only around 12 per cent of the capex projects are sensitive to the scenarios. That is, there are a relatively large number of projects which are driven by fundamental needs other than generation patterns and state load growth

- there is a relatively small range between the high, medium and low demand forecasts.

PB concluded these aspects explained the relative insensitivity of TransGrid's capex portfolio to changes in the scenario probabilities.[67]

---

61 EUAA, pp. 3−4.
62 EUAA, pp. 14−15.
63 EMRF, *A response by the EMRF*, August 2008, pp.14−15.
64 Snowy Hydro Limited, *Submission to TransGrid Revenue Proposal*, pp. 1−2.
65 PB, p. 93.
66 PB, p. 93.
67 PB, p. 93.

It is important to note since PB's review of TransGrid's initial proposal TransGrid has updated its probabilistic modelling to reflect the information from its 2008 APR. While this has impacted on the timing of a number of scenarios, PB's assessment of the underlying appropriateness of the probabilistic modelling methodology remains unchanged.[68] The impact of the changes associated with the release of the 2008 APR is detailed in section 3.3.2 and appendix B.

AER considerations

The AER considers that the methodology used by ROAM to develop TransGrid's forecast capex is robust. The AER notes that this approach has been successfully used in previous ex-ante determinations and that PB's analysis found the development of the scenario probabilities to be well considered and that the final scenario probabilities are realistic.

Regarding the EUAA's comments, the AER acknowledges that utilising the most recent available information when modelling is usually best practice but notes there are usually long lead times associated with developing regulatory proposals and modifying a scenario based model to fully reflect economic and policy uncertainties or recent changes is difficult.

That notwithstanding, the AER considers the EUAA's concerns are largely addressed as TransGrid's updated capex forecasts are based on more current economic and regulatory factors. The use of more recent data to inform TransGrid's capex proposal is reflected in recent (August 2008) correspondence sent to the AER following the release of TransGrid's 2008 APR. Through this correspondence TransGrid highlighted it was reducing its proposed capex as it was forecasting some softening growth in the demand for electricity:

> The 2008 APR has been produced during a period of considerable uncertainty regarding the impact of a Greenhouse Pollution Reduction scheme and forecasts some softening growth due to early expert estimates of the impact of the scheme on electricity prices.[69]

Further, PB's observations show that the underlying factors driving TransGrid's forecast capex are not drastically influenced by the introduction of a carbon trading scheme and the majority of the projects are required even in an environment with lower economic growth and lower demand. That is, there are a relatively large number of projects which are driven by fundamental need. Where network augmentation is required, this is often as a result of growing network congestion. Challenges associated with congestion are increasingly being encountered in the Newcastle − Sydney − Wollongong load corridor and northern NSW.[70]

Based on the material provided by TransGrid and PB's analysis, the AER agrees with PB's analysis on TransGrid's approach to probabilistic planning and considers that TransGrid has reasonably considered and factored into its modelling changes in the

---

68 PB, APR 2008 s*upplementary report*, pp. 7–17.

69 TransGrid, letter to the AER, 22 August 2008, p. 2.

70 See for example, the Bannaby − South Creek 500 kV lines and substation proposal. In terms of the growing constraint in northern NSW, to address this issue in the medium term TransGrid has recently released (10 March 2008) an application notice, *Supply to the Far North Coast*, for consultation.

economic and policy environment since it first developed its forecast capex proposal. With the release of the 2008 APR and the release of further information on policy parameters by state and commonwealth governments, TransGrid has utilised the latest available information in its probabilistic planning.

Furthermore, the AER agrees with PB's conclusion that ROAM's probabilistic scenario planning is robust and that it is an appropriate tool to use in the development of an ex-ante capex proposal. In particular, the AER considers that the scenarios and probabilities applied are reasonable, and the methodology overall enables TransGrid to develop the framework for an expenditure allowance that is reflective of expected planning conditions over the next regulatory control period.

3.6.4 Demand forecasts

One of the capex criteria the AER must be satisfied of in order to accept TransGrid's proposed forecast capex is that it reasonably reflects a realistic expectation of the demand forecast, as provided for in clause 6A.6.7(c)(3). Accordingly this section sets out the AER's consideration and assessment of TransGrid's demand forecast for the purposes of assessing its proposed forecast capex.

Maximum demand is the highest level of network capacity sought at a single point in time. TNSPs plan network augmentation to enable them to meet the expected maximum demand on their networks, and accordingly the maximum demand forecasts play an important role in the AER's assessment of TNSPs' load driven capex.

TransGrid publishes annual 10 year demand forecasts for NSW, in its APR. This section discusses whether TransGrid's demand forecasts can reasonably be relied upon for the purposes of developing its load driven capex and opex requirements over the next regulatory control period.

The AER's review of TransGrid's demand forecasts includes an assessment of the methods, inputs and data sources used by TransGrid for its energy, maximum demand and weather correction modelling.

TransGrid proposal

TransGrid used the demand forecasts in its 2007 APR to develop its forecast capex for the next regulatory control period.[71] Definitions and assumptions of NEMMCO's Load Forecasting Reference Group and information gathered by the National Institute for Economic and Industrial Research (NIEIR) on NEMMCO's behalf were inputs into TransGrid's demand forecasts.[72] TransGrid also relied on connection point forecasts developed by the ACT and NSW DNSPs when forecasting capex for joint projects with these businesses.[73]

TransGrid's revenue proposal included the forecasts for energy and maximum demand for the next regulatory control period listed in table 3.8. TransGrid produces maximum demand forecasts at 10, 50 and 90 per cent probability of exceedence

[71] TransGrid, *Revenue proposal*, p. 59, referring to TransGrid, *Annual Planning Report*, June 2007.
[72] TransGrid, *Revenue Proposal*, p. 56.
[73] TransGrid, *Revenue Proposal*, p. 57.

(POE).[74] The AER understands that the planning of TransGrid's main system capital and operating expenditure programs are based on the 10 per cent POE values, however, the 50 per cent POE values are also important in calculating critical line rating limitations.[75]

Table 3.8: TransGrid's energy and maximum demand forecasts 2009–14 (2007 APR)

	2009–10	2010–11	2011–12	2012–13	2013–14	Average growth 2009–14
Energy sent out (medium–case scenario) – GWh	78 000	78 890	80 060	81 520	82 900	1.5%
Demand (10% POE - medium–case scenario) – MW[a]	15 930	16 350	16 760	17 220	17 670	2.6%
Demand (50% POE - medium–case scenario) – MW[a]	14 620	14 970	15 320	15 740	16 140	2.5%

Sources: TransGrid, *Revenue proposal*, p. 58; TransGrid, *2007 APR*, table 4.3, p. 18.
(a) All values are for summer peak demand.

Key drivers of demand

TransGrid stated that the load growth experienced in NSW in recent decades has been primarily driven by increases in population and per capita consumption.[76] It also stated that TransGrid's network is moving to a summer peaking situation principally due to the growth in air conditioning use.[77]

Methodology

TransGrid's primary forecasts are based on top–down econometric models that forecast energy and peak demand for the NSW region as a whole.[78] TransGrid also develops a bottom–up forecast by summing forecasts provided by the DNSPs connected to its transmission network, and then reconciles the top–down and bottom–up forecasts.[79] TransGrid developed three statistical models used to forecast energy and maximum demand on its network over the next regulatory control period; an energy model, weather correction model and peak demand model.[80]

Submissions

The AER received two submissions that commented on TransGrid's demand forecasts and forecasting methodology, from Snowy Hydro and the EUAA.

Snowy Hydro submitted that TransGrid's maximum demand forecasts for the next regulatory control period appear conservative. Snowy Hydro submitted that NSW has

74 10 per cent POE temperatures are expected to be equalled or exceeded on average one year in ten; 50 per cent POE temperatures are expected to be equalled or exceeded on average one year in two; 90 per cent POE temperatures are expected to be equalled or exceeded on average every year.
75 TransGrid, response to Further Capex Questions V1_0, question PB6D1, 30 July 2008.
76 TransGrid, *Revenue Proposal*, p. 5.
77 TransGrid, *Revenue Proposal*, p. 5.
78 TransGrid, *Revenue Proposal*, Apprendix J, pp. 1−2.
79 TransGrid, *Revenue Proposal*, p. 2.
80 TransGrid, *2007 APR*, p. 68.

recently experienced a winter maximum demand that is only 200 megawatts below TransGrid's medium case maximum demand forecast for 2009–10.[81]

The EUAA noted that TransGrid's demand forecasts are based on its 2007 APR and that subsequent to TransGrid lodging its revenue proposal for the next regulatory control period, the 2008 APR was released. The EUAA noted that the 2008 APR revises TransGrid's demand forecasts downwards, and that this may have significant implications for the extent and timing of infrastructure investment requirements. The EUAA submitted that the AER should require TransGrid to update its capital expenditure modelling, and revise its capital expenditure forecast, to take into account the 2008 APR.[82]

Consultant review

The AER engaged McLennan Magasanik Associates (MMA) to undertake a desktop review of the methods and processes used to develop TransGrid's demand forecasts in the 2007 APR. MMA's final report is available on the AER website.[83]

MMA reviewed TransGrid's energy, weather correction and peak demand models. The key forecasts reviewed by MMA were the medium scenario energy sent out forecasts and the medium scenario 10 per cent POE maximum demand forecasts within the 2007 APR. MMA took into account previous reviews of the TransGrid processes, models and methodologies carried out by KEMA Inc. (KEMA) in 2005 and 2007.[84]

From its review of TransGrid's demand forecasts, MMA considered that:[85]

- the overall methods and processes adopted by TransGrid were appropriate, well considered and reasonable
- the weather correction model needs to be further validated, as it produces some anomalous results
- data sources for the air conditioning index in the peak demand model need to be improved. MMA considered that improvements to the peak demand model may result in the summer maximum demand 10 per cent POE forecast dropping from 2.5 to 2.1 per cent per annum between 2006 and 2014
- significant changes in the macroeconomic environment since the development of the 2007 APR indicate that the inputs to the model may be out of date. MMA estimated that an update could further reduce annual summer maximum demand growth forecasts to 2 per cent per annum.

---

81 Snowy Hydro Limited, *Submission to TransGrid Revenue Proposal*, p.1.

82 EUAA, *Submission to AER review of TransGrid's revenue proposal for 2009/10 to 2013/14*, 15 August 2008, pp. 24–25.

83 MMA, *Review of TransGrid demand forecasts for the period 1 July 2009 to 30 June 2014*, May 2008.

84 In 2005, and again in 2007, TransGrid engaged KEMA to conduct independent reviews of its demand forecasting methodologies. KEMA's final 2007 report was provided in TransGrid, *Revenue Proposal,* appendix J: KEMA Inc, *Review of TransGrid's Load Forecasting Methods, Final Report*, 12 June 2007.

85 MMA, *Review of TransGrid demand forecasts*, pp. 1−4.

AER considerations

In assessing the reasonableness of TransGrid's demand forecasts, the AER considered:

- reviews undertaken by KEMA in 2005 and 2007 on TransGrid's methodology for developing state demand forecasts
- a backcast review of TransGrid's 2007 peak demand model, published in NEMMCO's 2007 Statement of Opportunities
- MMA's review of TransGrid's 2007 APR demand forecast methodology and forecasts.

Reviews undertaken by KEMA in 2005 and 2007

TransGrid is a member of the national Load Forecasting Reference Group (LFRG). The LFRG is responsible for ensuring that demand forecasts in the NEM are prepared on a consistent basis. In 2005, the LFRG engaged KEMA to review the demand forecasting procedures used by all jurisdictional planning bodies in the NEM. This review found that TransGrid's load forecasting approaches use advanced time series analysis methods, and a model forecasting structure that has been established by recognised experts in energy demand forecasting. It also stated that TransGrid conducts extensive diagnostic testing of model forms and specifications. Overall KEMA found that these approaches are good practices but it suggested potential refinements.[86]

In 2007, TransGrid engaged KEMA to undertake a review of TransGrid's models and processes. KEMA found that TransGrid's long–term load forecasting methodology includes internationally recognised processes, and can be relied upon to produce a realistic expectation of demand forecast. KEMA also stated that the overall approaches used by TransGrid in developing the forecasts are sound, and combine good technical methods with good judgment and experience.[87]

Backcast review of TransGrid's 2007 peak demand model

In its 2007 Statement of Opportunities, NEMMCO published details of a five year backcast review using TransGrid's peak demand model from the 2007 APR.[88] In its consideration of TransGrid's forecasts, the AER had regard to this backcast review. The AER generally considers backcast reviews are useful in testing the robustness of a demand forecasting model.

The Statement of Opportunities noted that the backcast peak demands are close to the actual peak demands. The report noted that the backcast enables a high degree of confidence in the forecasting methodology.[89]

MMA's review

Energy model

---

86 KEMA, *Review of the process for preparing the SOO load forecasts*, 17 June 2005, p. 4.
87 TransGrid, *Revenue Proposal*, Appendix J, p. 1.
88 A backcast review seeks to assess the accuracy of a forecasting model by testing sample data. NEMMCO, *2007 Statement of Opportunities*, 2007.
89 NEMMCO, *2007 Statement of Opportunities, Appendix B*, p. B8.

TransGrid's energy model evaluates energy generated, sent out and supplied for its region as a whole on a monthly basis, and relates energy consumption to broad demographic, economic and weather variables.[90] These variables include historical energy (net of large direct industrial loads), average retail electricity and gas prices, income per capita (real gross state product), the real interest rate and cooling and heating degree days.[91] Historical and forecast seasonal energy data produced by the energy model is used as an input into TransGrid's peak demand model.

KEMA described the energy model as 'an error correction model [that] provides estimates of the long–run response of consumption to the economic drivers and the short–run responses to changes in these drivers over the last few periods.'[92]

MMA considered that TransGrid's energy model is appropriate, however, stated its concern that the resulting forecasts were developed prior to significant changes in the macroeconomic environment which may impact upon maximum demand, such as the worsening of the United States sub–prime lending crisis. MMA concluded that the energy forecast (and maximum demand forecasts) might be out of date due to significant changes in the macroeconomic environment since the 2007 APR was completed.[93]

Weather correction model

TransGrid's weather correction model analysed historical demands and weather conditions to determine a probability distribution of demand for each season of each year, subject to a range of possible weather patterns.[94] The model estimated the effects of a number of weather variables on half–hourly demand, including:

- cooling and heating degree days[95]
- days of the week
- public holidays
- seasonal effects.

TransGrid created fifty weather scenarios corresponding to the years ending March 1958 to 2007, which were used in the weather correction model to determine the range of possible demand outcomes in each year. The model resulted in fifty estimates for summer and winter maximum demand for each year, from which peak demands at the 10, 50 and 90 per cent POE were extracted.

While initially, MMA did not have any concerns with the TransGrid weather correction methodology, examining the model outputs revealed unexpected patterns

90 TransGrid, *2007 APR*, p. 68.
91 TransGrid, *2007 APR*, p. 69.
92 TransGrid, *Revenue Proposal,* Appendix J, pp. 3−5.
93 MMA, *Review of TransGrid demand forecasts,* p. 49.
94 TransGrid, *Revenue Proposal*, p. 57.
95 Cooling degree days are measured on a monthly basis, and are the sum of the divergences of daily average temperatures above 21 degrees Celsius. Heating degree days are measured on a monthly basis, and are the sum of the divergences of daily average temperatures below 18 degrees Celsius.

among cooling degree day coefficients.[96] MMA found that TransGrid's weather correction model demonstrated a strong bias towards the 2007 maximum demand occurring on a Tuesday, and a strong bias against it occurring on a Wednesday.[97] MMA considered these results were unexplainable. MMA recommended that TransGrid improve its weather correction methodology by using the normalisation models stochastically rather than deterministically to enable the model to generate more representative peak demand.[98]

TransGrid implemented MMA's recommendations on its weather correction model in preparing its forecasts within the 2008 APR.[99]

Peak demand model

TransGrid's peak demand model related each season's peak demand to average demand throughout the season.[100] It also related peak demand to a varying trend in the installation of air conditioning, based on observed changes in the load factor.[101] The model estimated peak demand for summer and winter at 10, 50 and 90 per cent POE.[102]

After analysing TransGrid's peak demand model, MMA found that the average demand parameter was mis-specified in implementing the model, which MMA assumed was an unintended error.[103] TransGrid confirmed with MMA that this was an error, and estimated that it resulted in a slight reduction of its summer 10 per cent POE growth rate.[104]

TransGrid's air conditioning index, which was an input into the peak demand model, was based on TransGrid's own assumptions about air conditioning growth.[105] MMA stated that TransGrid did not appear to have taken account of best available information, including historical data published by the Australian Bureau of Statistics (ABS). MMA considered that revising TransGrid's maximum demand forecasts based on historical ABS data would result in a reduction in TransGrid's summer maximum demand forecast of 490 MW by 2014.[106] MMA recommended that TransGrid should revise its peak demand model using an air conditioning index based on better data.[107]

TransGrid implemented MMA's recommendations on its peak demand model in preparing its forecasts within the 2008 APR.[108]

---

96 MMA, *Review of TransGrid demand forecasts*, p. 37.
97 MMA, *Review of TransGrid demand forecasts*, p. 37.
98 MMA, *Review of TransGrid demand forecasts*, p. 39. However, MMA indicated this improvement may not overcome the issues related to the functional form of the model.
99 TransGrid, email to the AER: MMA review of TransGrid demand forecast, 15 October 2008.
100 TransGrid, *2007 APR*, p. 76.
101 TransGrid, *2007 APR*, p. 76.
102 TransGrid, *2007 APR*, p. 76.
103 MMA, *Review of TransGrid demand forecasts*, p. 42.
104 MMA, *Review of TransGrid demand forecasts,* p. 42.
105 MMA, *Review of TransGrid demand forecasts*, pp. 41−42.
106 Values are 50 per cent POE. MMA, *Review of TransGrid demand forecasts*, p. 42, table 4-7.
107 MMA, *Review of TransGrid demand forecasts*, p. 44.
108 TransGrid, email to the AER: MMA review of TransGrid demand forecast, 15 October 2008.

2008 APR

On 30 June 2008, TransGrid published its 2008 APR, and 2008 load forecasts.[109] Table 3.9 contains the energy and demand forecasts within the 2008 APR.

Table 3.9: TransGrid's energy and maximum demand forecasts 2009–14 (2008 APR)

	2009–10	2010–11	2011–12	2012–13	2013–14	Average growth 2009–14
Energy sent out (medium–case scenario) – GWh	76 120	76 280	76 760	77 820	78 420	0.8%
Demand (10% POE – medium–case scenario) – MW[a]	15 180	15 530	16 020	16 390	16 750	2.5%
Demand (50% POE – medium–case scenario) – MW[a]	14 290	14 620	15 070	15 410	15 730	2.4%

Source: TransGrid, *2008 APR*, tables A3.1 and A3.2, pp. 88–89.
(a) All values are for summer peak demand.

The 2008 APR notes the following significant changes between the 2007 and 2008 forecasts:

- the energy forecast is 3.1 per cent down
- the summer peak demand forecast is 4.5 per cent down
- the winter peak demand forecast is 3.1 per cent down.[110]

TransGrid's capex program within its revenue proposal was developed based on the demand forecasts within the 2007 APR. Following the completion of MMA's final report and the release of the 2008 APR, it was agreed that TransGrid would update its proposed capex projects to take account of the 2008 APR. This involved TransGrid reassessing its entire capex proposal in light of the new forecasts, and resulted in amendments to its capex, opex and service standards proposals.

The AER acknowledges that significant instability in international financial markets, and falls in economic growth associated with the failure of numerous major financial institutions and general weakness in global markets, occurred largely subsequent to the release of TransGrid's 2008 APR. However, the AER considers that the recent changes in the world economy were somewhat anticipated by the course of events related to the United States sub–prime lending crisis, which began to emerge around February 2007.[111]

[109] TransGrid, *Annual Planning Report*, 20 June 2008.
[110] TransGrid, *2008 APR*, pp. 20−21. These figures are for native energy, or total energy supplied by both scheduled and non-scheduled generators.
[111] Reuters – ABC News, *US stocks slide on housing woes*, 10 February 2007, viewed 15 October 2008, Canberra <http://www.abc.net.au/news/stories/2007/02/10/1844683.htm>.

In developing the 2008 APR, TransGrid relied upon economic growth projections made by the NIEIR.[112] NIEIR provided medium, high and low economic growth scenarios for NSW, used as inputs into TransGrid's forecasts. In its 2008 forecast, NIEIR projected lower economic growth for the TransGrid region than in 2007, reflecting a more uncertain economic outlook.[113] The AER considers that NIEIR's economic forecast, used as an input into the 2008 APR forecasts, accounts for the recent slowdown in growth worldwide, by acknowledging an uncertain economic outlook related to the United States sub−prime crisis.

It may be that following the global financial and economic downturn, more recent information indicates demand on TransGrid's network for the next regulatory control period may be lower than that forecast in the 2008 APR. However, the AER notes that a forecast can only rely on the best information available at the time it is prepared. In order to assess the reasonableness of TransGrid's capex proposal, it was necessary for the AER to commit to assessing the forecasts prepared in the 2008 APR, and in effect agree that information available subsequent to the 2008 APR could not be given the same weight as material provided earlier in the review process. However, noting the uncertain economic outlook assumed by NIEIR, the AER considers that the forecasts within the 2008 APR are based on reasonably recent information regarding the factors influencing the demand for electricity in NSW.

The AER notes Snowy Hydro's submission that it considers TransGrid's maximum demand forecast for the next regulatory control period to be conservative. As noted above, during the AER's review, TransGrid revised its capex program downwards based on the updated demand forecasts provided in the 2008 APR. The 2008 APR forecasted a contraction in summer and winter maximum demands as compared to the 2007 APR. The AER considers the maximum demand forecasts within the 2008 APR underpinning TransGrid's capex program for the next regulatory control period relies, are reasonable.

The AER notes the EUAA's submission that the AER should require TransGrid to update its capex forecast to take account of the 2008 APR. During the course of the AER's review, TransGrid provided an updated capex program for the next regulatory control period based on the 2008 APR. The AER's and its consultant's consideration of the updated capex program is summarised in section 3.3.2 and appendix B.

AER conclusions

On balance, having considered previous reviews of TransGrid's forecast methodology, a backcast review of TransGrid's 2007 APR forecasts, and MMA's findings on TransGrid's forecast methodology, the AER considers TransGrid's demand forecast methodology is appropriate, and that its 2008 APR forecasts provide a realistic expectation of demand for the next regulatory control period. Accordingly, the AER is satisfied the demand forecasts reasonably reflect a realistic expectation in accordance with the capex criterion set out at clause 6A.6.7(c)(3) of the NER.

[112] TransGrid, *2008 APR*, p. 20.
[113] TransGrid, *2008 APR*, p. 21.

3.6.5 Network planning criteria

This section examines whether TransGrid's planning criteria is consistent with the NER and its legislative obligations. Compliance with legislative obligations is the subject of the capex objective set out at clause 6A.6.7(a)(2) and as such this issue is relevant for the AER in determining whether it is satisfied TransGrid's proposed forecast capex reasonably reflects the capex criteria.

Under the NER, TransGrid's planning obligations are set out in schedule 5.1, and in particular, clause S 5.1.2.1 which states:

> Network Service Providers must plan, design, maintain and operate their transmission networks to allow the transfer of power from generating units to Customers with all facilities or equipment associated with the power system in service and may be required by a Registered Participant under a connection agreement to continue to allow the transfer of power with certain facilities or plant associated with the power system out of service, whether or not accompanied by the occurrence of certain faults (called "credible contingency events").

The rules also set out processes for developing networks and specify the minimum performance requirements of the network and for connection to the network.[114]

Under NSW legislation, TransGrid's planning obligations are linked with the licence obligation placed on DNSPs.

Network planning criteria form the basis for assessing the requirement for and design of load driven capex.

TransGrid proposal

TransGrid noted its planning responsibilities are set out in the NER and specific NSW legislation. A key aspect of TransGrid's planning criteria is the need to meet the mandatory DNSP licence conditions introduced by the Department of Energy Utilities and Sustainability in 2005 and 'n−1, 1 minute' reliability standards for sub–transmission lines and zone substations supplying certain specified minimum loads (e.g. 15 MVA for urban and non-urban areas). Implied in these licence conditions is the requirement for TransGrid to plan its network to enable the DNSP licence requirements to be met unless specifically agreed otherwise with the affected distribution network owner or major directly connected end-use customer.[115]

In addition to the NER requirements, TransGrid also takes into account the historical performance of the network, the sensitivity of loads to interruption, and its asset maintenance procedures when planning its network.

In response to these requirements, TransGrid developed a set of deterministic planning criteria that are initially applied to identify potential constraints, and are then subject to further assessment.

TransGrid also published a *Strategic network development plan 2008: A long term vision of the NSW transmission network* as part of its planning process. This plan outlines how TransGrid expects demand, load and greenhouse abatement to develop

[114] TransGrid, *Revenue proposal,* p. 17.
[115] TransGrid, *Revenue proposal*, pp, 53–54.

over the medium to long term. It also notes that while it does not have a role in determining the type, timing or location of new generation developments, it does have a role to manage and plan the electricity transmission network for a range of likely generation development scenarios. Consequently, it develops a range of generation development scenarios that are considered to be likely and uses them in formulating its network development options (section 3.6.3).

Consultant review

From its review of TransGrid's network planning PB found:[116]

- its main system planning is based on specific criteria that reflect its planning obligations under the NER and NSW jurisdictional requirements
- its planning approach demonstrates a prudent approach to forward planning and its planning and documentation processes appear to be well structured and integrated. The planning process is also well defined and appropriate review points are present and aligned with critical decisions
- it has defined clear responsibility for identifying the need for projects and further, it has identified the full range of processes that might generate the need for a project
- it undertakes scenario based planning to assess network capability under a number of NEM load/generation scenarios. This involves the development of a range of scenarios that are based on consideration of a number of relevant factors, such as generation costs, government policy impacts, energy technology and energy industry developments
- the use of an accelerated planning process for capital works planning is reasonable for the purpose of preparing its revenue proposal
- its planning process is consistent with good industry practice and employs sound practices to inform the degree of augmentation in the transmission network.

AER considerations

The AER considers that TransGrid's planning procedures and processes are consistent with good industry practice and that it employs sound practices to inform the degree of augmentation in the transmission network. The AER has come to this conclusion following consideration of material provided by TransGrid and PB's analysis. In particular, the AER notes, with respect to the main transmission network, that PB found that TransGrid considers appropriate factors in its planning deliberations, including:

- overall load growth
- generation requirements
- NEMMCO's imperative to operate the network in a secure manner.

[116] PB, pp. 42−43.

Furthermore, and as discussed in section 3.6.3, the AER considers the probabilistic scenario planning methodology used by TransGrid to assist it in its planning requirements is robust.

Where consultation or joint planning is required, the AER also considers that it appears that TransGrid gives appropriate consideration to the NER requirements as it consults with interested parties before it commits to large network assets. In addition, TransGrid has indicated it conducts joint planning sessions with major generators and the NSW DNSPs on at least an annual basis. A joint demand forecasting meeting is also held with the NSW DNSPs on an annual basis.

On balance, based on the evidence provided by TransGrid and PB's analysis, the AER considers that while TransGrid's network planning framework is consistent with good industry practice and reflective of a prudent and efficient TNSP, improvement in documentation associated with land purchase planning could yield benefits in the form of improved efficiency.

3.6.6 Agreed changes to TransGrid's capex proposal

In undertaking the review of TransGrid's capex proposal PB and TransGrid identified a number of corrections that resulted in material adjustments to the calculation of the forward capex. These were advised by TransGrid as part of a formal change management process with PB. The adjustments typically related to discrepancies between the values entered into TransGrid's capex model and the values contained in the supporting documentation. The adjustments accounted for a total of $9.9 million and are summarised in table 3.10.

The AER notes that while a number of discrepancies were identified, which are of general concern, in total the discrepancies represented a small amount of total expenditure. Furthermore, TransGrid was forthcoming in identifying errors which were not always in its favour and they were incorporated in a timely manner.

Table 3.10: Agreed project adjustments ($m, 2007–08)

Project	Issue	Initial value	Adjustment	Final value
6172 – Molong transformer	Double counting	4.2	–4.2	–
6245 – Communication PNX	S-curve adjustment	5.7	–2.9	2.8
Correction of escalators	Labour and material escalators	228.4	7.1	235.5
5890 – Tamworth transformer replacement	Incorrect option included	15.9	–4.3	11.6
5860 – Tarro–Stroud 132 kV line	Incorrect option included	43.0	–4.5	38.6
6294 – Murray transformer replacement	Incorrect option included	21.1	–6.7	14.4
6001 – Waratah West 2nd transformer and 95N line conversion	Inconsistency with document PSR 199	16.0	4.9	20.9
6266 – Tomago 3rd transformer	Inconsistency with regulatory test final report	11.5	4.9	16.4
5950 – Sydney North No. 5 transformer	Inconsistency with document PES5950	11.4	–2.4	9.0
4905 – Delle CB replacement	Double counting	3.1	–1.0	2.1
Steel escalation weighting	Agreed change to weightings		–0.8	–0.8
Total		360.3	–9.9	350.4

Source: PB, p. 115.

3.6.7 Detailed review of selected forecast capex projects

The objective of the detailed sample project review is to gain an understanding of their costing as well as TransGrid's key planning and forecasting processes as they relate to the entire proposed forecast capex allowance. This assessment is relevant in determining whether the AER is satisfied the proposed forecast capex reasonably reflects the capex criteria.

The AER engaged PB to undertake a detailed review of a sample of projects from TransGrid's capex proposal to ensure that it is in accordance with the requirements of clause 6A.6.7 of the NER.

PB was required to critically analyse and comment on the level of TransGrid's proposed forecast capex allowance, taking into account the following factors:

- the existing network capacity
- asset utilisation

- asset lives
- asset conditions
- demand growth
- trade-offs between capex and opex
- information on historical and forecast capex trends
- the need to meet specified service, network, environmental and other regulatory requirements under relevant jurisdictional or other laws
- any other internal or external factors that may be relevant.

PB also provided a supplementary report to the AER which took into account the impact of the 2008 APR on the individual project reviews.[117] Additional information on the individual project reviews is provided in appendix B.

TransGrid proposal

TransGrid's initial forecast capex program consisted of over 160 projects that may take place during the next regulatory control period. The projects included in TransGrid's capex program included augmentation, replacement, easement and, security and compliance projects.[118]

Consultant review

PB reviewed 11 capex (nine network and two non-network) projects with a total value of $1.04 billion or 40 per cent of TransGrid's initial capex allowance.[119] The sample of projects was selected in consultation with the AER and was targeted to cover the range of factors that underpin TransGrid's forecast capex allowance. The sample list of network projects reviewed is provided in table 3.11. The weighted average value for the projects listed reflects the total (deterministic) project value combined with the probability of it occurring under each of the 36 scenarios outlined in section 3.6.3. The sample list of the two non-network projects reviewed is provided in table 3.12.

Through detailed project reviews PB examined 32.2 per cent of the planned network expenditure on a scenario weighted average basis and 86.4 per cent of the planned non-network capex.

In assessing the efficiency of each sample project, PB was required to provide its opinion on whether:

- there was a need for the project
- TransGrid had considered a reasonable range of alternatives
- the scope, cost and timing of the proposed project was reasonable

[117] PB, *APR 2008 supplementary report*, 12 November 2008.
[118] PB, p. 93..
[119] PB, pp. 116, 175.

- the project aligns with TransGrid's strategic plans, governance arrangements, and capex policies and procedures.

Table 3.11: PB's detailed project review – network sample project list ($m, 2007–08)

Project name	Category	Total	Weighted average
Bannaby – South Creek 500 kV lines & substation	Augmentation (easement)	322.5	247.6
Holroyd – Chullora 330 kV cable	Augmentation (easement)	244.5	244.5
Dumaresq – Lismore 330 kV line	Augmentation	165.5	165.5
Communication – South West NSW microwave & satellite	Augmentation	4.8	4.8
Wallerawang No. 1 & 2 transformer	Augmentation	19.0	19.0
Cooma 132 kV substation replacement and new bay	Replacement (easement)	42.8	42.8
Beaconsfield West 132 kV GIS replacement	Replacement	48.1	48.1
Newcastle 330 kV substation transformer replacement	Replacement	18.9	18.9
Hunter Valley – Central Coast 500 kV lines	Easements (augmentation)	42.6	4.2
Total		908.7	795.4

Source: PB, p. 117.

Table 3.12: PB's detailed project review – non-network sample project list

Project name	Forecast non-network expenditure	
	Value ($m, 2007–08)	% of total
Business IT	95.9	45.7
Vehicles	39.1	18.6

Source: PB, p. 175.

Based on its detailed review of a sample of capex projects, PB recommended a reduction of $77.2 million ($2007–08) from TransGrid's initial capex proposal.[120] Table 3.13 illustrates the reductions recommended by PB against each project.

[120] In total, PB recommended a reduction of $128.6 million (4.9 per cent) from TransGrid's initial $2626.9 million revenue proposal. Table 3.12 does not include PB's recommended reductions arising from the application of risk and scoping factors, escalations, agreed adjustments and replacement programs.

Table 3.13: PB's recommended adjustments from detailed project reviews – TransGrid's initial capex proposal ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid initial capex proposal	536.8	495.9	748.1	523.8	322.3	2626.9
Bannaby − South Creek 500 kV lines and substation	–	–	–	–	–	–
Holroyd − Chullora 330 kV cable	–	–	–	–	–	–
Dumaresq − Lismore 330 kV line	–1.2	–17.6	–17.6	–	–	–36.4
Wallerawang No.1 & No.2 transformer	–0.3	–	–	–	–	–0.3
Cooma 132 kV substation replacement	4.8	4.8	3.8	–6.5	–25.2	–18.2
Beaconsfield West 132 kV GIS replacement	–0.4	–1.2	–1.8	–4.7	–	–8.1
Newcastle 330 kV substation transformer replacement	–	–	–	–10.5	–	–10.5
Hunter Valley − Central Coast 500 kV line easements	–	–	–	–0.1	–0.9	–1.0
Communication – South West NSW microwave & satellite	–	–	–	–	–	–
Business IT	–	–	–	–	–	–
Vehicles	–	–	–	–	–	–
Total adjustments	3.2	–14.0	–15.4	–19.7	–31.4	–77.2

Source: PB, p. 246.

Overall, while PB's detailed review of TransGrid's initial capex proposal found it to be generally reasonable in terms of prudence and efficiency it did find systemic issues, where there was scope for improvement. In particular, PB found issues with TransGrid's:[121]

- application of scoping and cost factors which lacked transparency
- options analysis, which was inadequate.

With reference to TransGrid's option analysis, PB considered it:[122]

- failed to include all relevant information and sensitivity analysis was not used to inform the options choice

[121] PB, pp. 158−159.
122 PB, p. 159.

- did not rely on the results of the options analysis, but tended to rely on qualitative arguments to dismiss the findings of the economic options analysis to justify its preferred option.

AER considerations

The AER considers, based on the information provided by TransGrid and PB's analysis, that the sample of capex projects reviewed in detail were mostly prudent and efficient. The AER notes that PB proposed adjustments to six projects where it determined there were modelling and or analytical errors:

- two project costs being reduced by $28.7 million due to the lack of evidence that the proposed option was reflective of what an efficient TNSP would select—Cooma 132 kV substation replacement and the Newcastle 330 kV transformer replacement projects

- the cost of one option being reduced by $36.4 million to reflect, amongst other factors, a reduction in technical requirements—Dumaresq − Lismore line augmentation project

- one option's costs being reduced by $0.3 million to reflect the lack of strategic consideration associated with the works on site—Wallerawang No. 1 & No. 2 transformers replacement project

- one option's costs being reduced by $1 million to reflect more appropriate land costs—Hunter Valley − Central Coast 500 kV line easement

- the cost associated with the Beaconsfield West 132 kV GIS replacement project was affected significantly by changes in the application of the scoping factors.

The AER agrees with PB's finding that in many cases TransGrid has relied on engineering judgement, which has not been transparently applied, to select a particular project option which would not be the preferred option on economic grounds. Furthermore, the AER considers that the NPV assessments underlying several investment decisions have not been complete and often omitted certain costs and benefits. The AER also notes that judgement has been applied in the scoping and costing of several projects, and in the development of TransGrid's risk allowance.

The AER acknowledges that when requested to provide further analysis on its proposal, TransGrid was forthcoming with this information and the AER and PB generally found TransGrid's decisions to be reasonable, although with some exceptions.

The AER considers that TransGrid has scope to improve its analysis of potential investments with regards to:

- including all quantifiable costs and benefits in NPV analyses

- subjecting investment decisions to sensitivity analysis where options are closely ranked or are based on uncertain parameters

- properly documenting the basis for decisions (including the dismissal of alternative investment options and changes in project costs) that are based on judgement, with reference to credible evidence where possible.

Where costs/benefits can not be quantified, there is also scope for TransGrid to more fully document and consistently apply qualitative information. In this context, mechanisms such as 'multi-criteria analysis' may be useful to demonstrate the suitability of investment options.[123]

The AER accepts that in developing its expenditure proposal that it may not be practical (due to the relative materiality of some of the projects, unknown variables and cost) for TransGrid to perform a thorough options analysis for all projects that it expects to undertake in the next regulatory control period. The AER also accepts that informed individuals within TransGrid may regard certain things as obvious based on their expertise and role in the organisation. However, TransGrid is required, under the NER, to submit a proposal that is of a sufficient detail to satisfy the AER that it reasonably reflects the capex criteria. Moreover, robust options analysis is paramount for projects of the type undertaken by TransGrid which involve very large amounts of expenditure and are strategically significant to the NEM.

The AER's considerations of PB's recommendations and issues associated with each project review are set out below. This consideration includes a separate discussion on the impact of the 2008 APR on TransGrid's initial revenue proposal and PB's recommendations where appropriate. Costs detailed in this consideration are based on TransGrid's initial proposal unless otherwise stated to be the updated by cost estimates from the 2008 APR. Appendix B also provides further details on the AER's consideration of these projects.

Although the AER is requiring a number of adjustments based on a specific project review, it is important to understand it is the total of the proposed forecast capex allowance which the AER must either accept or reject, on the basis of the capex criteria having regard to the capex factors. In accordance with the ex ante framework provided for in Chapter 6A, the AER's project specific conclusions do not bind TransGrid to a particular set of project specific capex budgets—TransGrid has the ultimate discretion on how it allocates its capex allowance.

Bannaby − South Creek 500 kV lines and substation

TransGrid's proposal indicated new line reinforcement is required between Bannaby and Sydney by 2013–14 due to the growing load in the Newcastle − Sydney − Wollongong area. This project is part of TransGrid's long term strategy to develop a

[123] The application of this technique requires judgements about how proposed options will contribute to a series of criteria that are chosen to reflect the benefits and costs associated with the proposals. A qualitative score would be assigned, depending on the impact of the option on each of the criteria measured relative to the base case. For instance, each criterion rating scale could have a range of –10 to +10, and a score of 10 would indicate that the option has twice the impact of an option with a score of 5 (and five times the impact of an option with a score of 2 etc). For example, if one option incurred costs of $3.5 million per year, and another option $7 million, then the former option might receive a rating of –5, while the latter would score – 10. A scale from 1 to 10 is preferred as it is easier to include more information on the choices made, and this results in a greater understanding of the proposal. When evaluating options, the reason(s) for assigning different scores needs to be clearly articulated. Source: Department of Treasury and Finance (Victoria) 2007, *Victorian Guide to Regulation, Second edition*, pp. 5−18.

500 kV system around the Newcastle − Sydney − Wollongong load corridor. This proposal has an initial estimated cost of $248 million or 9.4 per cent of TransGrid's initial capex allowance. With the release of the APR 2008 this proposal is deferred (0.9 years) and has an updated estimated cost of $167 million.[124]

PB considered that while a reasonable range of alternative options had been identified, the options analysis undertaken had room for improvement. In particular, PB raised concerns with the lack of:[125]

- analysis associated with NPVs of the options presented – while costs were presented, no consideration was presented of the comparison of the NPVs of the various options
- sensitivity analysis of the options presented
- reference to a 'do nothing' option to facilitate a robust reference point for the consideration of other options.

Nonetheless, PB acknowledged the qualitative assessment of the costs and benefits presented by TransGrid demonstrated the merits of the preferred option over the alternatives considered.[126]

The AER considers that this project is of strategic importance as part of reinforcement of the Newcastle − Sydney − Wollongong load corridor, and in meeting the generation developments that are expected to occur to meet growth in this area. Based on documents provided by TransGrid and PB's analysis, the AER considers that TransGrid has identified and selected the preferred option following consideration of an extensive range of practical alternatives to meeting this identified need. However, the AER agrees with PB's analysis that the comparison of the NPVs of the options could have been presented and that more extensive use of sensitivity analysis could have occurred. This is particularly important given the relative size and importance of this project.

Having considered the material presented by TransGrid and PB's analysis, the AER is satisfied that the cost of $167 million associated with the Bannaby − South Creek 500 kV lines and substation option reasonably reflect those which a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives in accordance with the capex criteria.

Holroyd − Chullora 330 kV cable

TransGrid's proposal involves the installation of two 330 kV cables to reinforce supply to inner Sydney. The project initially had a proposed commissioning date of 2013 and has an estimated cost of $245 million or 9.3 per cent of TransGrid's initial capex allowance. With the release of the APR 2008, this project is deferred (0.2 years) and has an estimated cost of $247 million.

On the basis of the original documentation provided by TransGrid, PB considered the need to install the second 330 kV cable within the next regulatory control period had

[124] PB, *APR 2008 supplementary report*, p. 22.
[125] PB, p. A35.
[126] PB, p. A35.

not been demonstrated. PB also noted TransGrid had not undertaken any sensitivity analysis to demonstrate the impact of different timing options for the second cable in terms of NPV calculations.

In discussions with PB and TransGrid it was noted that the timing of the second cable was critical to the project scope, since had it not been required within five years it would have resulted in significant changes to the NPVs of the options considered. In particular, the change in the timing of the installation of the second cable could have resulted in a staged installation of the cables being the more efficient option. It was also noted that deferral of the installation of the second cable would result in duplicating the disruption along the proposed cable route within a relatively short time period.

PB's draft report recommended a reduction in the capex associated with this project by $95 million to reflect the cost of installing one cable only. TransGrid subsequently provided information that demonstrated the need for the second cable within five years of the installation of the first. Based on this supplementary advice PB concluded TransGrid had demonstrated the need, scope and cost efficiency of this proposal.[127]

The AER considers that TransGrid could have presented a more robust case to demonstrate the efficiency of this proposal over other alternatives earlier in the review process. In particular, the AER agrees with PB's initial concerns regarding the lack of justification for the timing of the second cable and the lack of sensitivity analysis regarding its timing. These concerns are amplified given the amount of expenditure associated with the second cable, around $95 million or 3.6 per cent of TransGrid's initial capex proposal.

The AER is, nonetheless, satisfied that TransGrid has ultimately demonstrated that both cables are required[128] and that the expenditure associated with the installation of the both 330 kV cables in the next regulatory control period reasonably reflects the efficient costs a TNSP in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria. The AER, therefore, recommends no adjustment to TransGrid's forecast capex allowance as a result of this project review.

Dumaresq − Lismore 330 kV augmentation

TransGrid's proposal involves an additional 330 kV transmission line from Dumaresq to Lismore by 2012 to meet growing demand in the far north coast of NSW and address corresponding voltage and line loading limitations. This project has an estimated cost of $166 million or 6.3 per cent of TransGrid's initial capex allowance.

PB's analysis identified a number of concerns with this project, including:[129]

---

127 PB, p. A49.

128 TransGrid provided evidence from EnergyAustralia that indicated that it was intending to withdraw from service a number of 132 kV cables in inner Sydney that are becoming unserviceable within the next regulatory control period. Consequently, TransGrid was able to demonstrate to PB and the AER's satisfaction that installation of two cables at the same time represented the most efficient option.

129 PB, p. A58.

- options that were considered infeasible and dismissed without sufficient rigour and transparency
- double counting of a $22 million easement in the project
- insufficient justification for the number of 330 kV circuit breakers proposed for the Dumaresq substation
- lack of transparency in the application of a generic 'scoping cost factor on line works' applied to line construction costs
- application of unreasonably high CPI adjustment (10.1 per cent) in TransGrid's modelling. PB considered that a CPI adjustment of 6.2 per cent was more reflective of actual inflation.

Consequently, PB concluded TransGrid had not demonstrated its proposal was prudent and efficient and recommended a $36 million reduction to TransGrid' capex allowance.[130]

Based on documentation provided by TransGrid and PB's analysis, the AER considers this project represents prudent investment. However, the AER agrees with PB's findings that TransGrid has not reasonably demonstrated that all the circuit breakers identified by TransGrid are required by a prudent and efficient TNSP in TransGrid's circumstances.

The AER also notes PB's concern with the 'scoping cost factor on line works' and its recommendation that this be reduced from 15 per cent to 10 per cent to reflect an efficient scoping allowance. The AER supports this reduction as the scope of this project is relatively well known to TransGrid and reasonably reflects the costs that would be incurred.

The AER also agrees with PB's analysis that TransGrid has applied an inflation adjustment that is too high and not reflective of the 2-year CPI escalation. That is, a CPI adjustment of 6.2 per cent, rather than TransGrid's proposed adjustment of 10.1 per cent, is more reflective of the inflation rate that a prudent operator in TransGrid's circumstances would be expected to incur.

The AER is therefore not satisfied that TransGrid has proposed a level of capex that reasonably reflects the efficient costs that a TNSP in the circumstances of TransGrid would require to meet the capex objectives, as required by clause 6A.6.7(c). Accordingly, the AER has reduced TransGrid's proposed capex allowance by $36 million.

Wallerawang No. 1 & No. 2 transformers

TransGrid's proposed expenditure for this project involves the commissioning of two 330/132 kV transformers at Wallerawang in 2010. This project has an estimated cost of $19 million or 0.7 per cent of TransGrid's initial capex allowance.

In 2007 the No.1 transformer failed and was replaced with a temporary transformer which is not fully compatible with the existing supply arrangements. Furthermore,

[130] PB, p. A58.

due to its temporary arrangement, it does not permit maintenance access to the No. 2 transformer. The No. 2 transformer is also of the same age as the failed No. 1 transformer and has the same fault conditions that caused the No. 1 transformer to fail.

PB considered TransGrid had not considered the overarching needs of the Wallerawang site in a holistic manner and considered that if TransGrid's strategic planning is improved it would permit greater efficiencies to be captured. For example, the costs of the Wallerawang 132 kV substation switchyard rebuild project could be reduced if it was undertaken in conjunction with the transformer replacement project. PB, therefore, recommended a $0.3 million reduction to account for these inefficiencies.[131]

In viewing TransGrid's options analysis the AER notes that TransGrid selected the most expensive option for inclusion in its capex allowance. However, the AER notes this option has a number of benefits including:

- it removes outage access constraints
- it addresses reliability issues at Wallerawang and restores normal duplicated supply to Wallerawang Power Station as well as enabling faster supply restoration due to spares availability
- outage requirements for construction and commissioning are manageable
- it minimises environmental risks through the upgrade of the oil containment system
- it allows full separation of functions from the power station site—that is, transformers are no longer located on the power station runway, and control and protection systems are separated.

Based on the material provided by TransGrid and advice from PB, the AER considers the replacement of both transformers and the re-arrangement of the supply arrangement is a prudent and efficient option. This determination has been reached following careful consideration of the circumstance associated with the plant failure, the replacement of the failed unit with non-standard equipment and the range of benefits associated with the selected option (as detailed above).

While the AER considers that TransGrid's proposal may be on the high side and that there may be scope for some efficiencies to be captured through more effective planning of all proposed works at this site, it does not consider this expenditure, in the context of TransGrid's overall capex proposal, to be unreasonable. The AER is therefore satisfied the expenditure sought for this project reasonably reflects the efficient costs a prudent TNSP in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria.

[131] PB, p. A74.

Cooma 132 kV substation replacement

TransGrid's proposal states that the Cooma 132 kV substation needs to be replaced on a new site by 2014 due to its poor condition and issues with the arrangement of the substation. The project has an estimated cost of $43 million or 1.6 per cent of TransGrid's initial capex allowance.

PB found the Cooma 132 kV substation has a range of condition and design related issues and that, while these needed to be addressed, TransGrid's condition assessments did not find any clear risks that the substation's transformers and regulators would fail.

PB highlighted TransGrid had selected the replacement of the substation at a new site—the most expensive option considered—on the basis that it resulted in a greater reduction in risk. Furthermore, it identified a number of concerns with TransGrid's options analysis, in particular:[132]

- full consideration was not given to the refurbishment of the transformers and regulators
- provision for a 330 kV substation layout was made in the remote replacement option but not in the other options. The justification for this provision was not provided by TransGrid
- some costs for new control and protection in the in-situ replacement options were overstated.

PB concluded the most efficient option to address the need identified by TransGrid would be to refurbish the substation on its existing site (without busbar works) and therefore recommended that TransGrid's capex allowance be reduced by $18 million to reflect this option (with a further $0.6 million removed due to an identified easement no longer being required).[133]

Through consideration of the information presented by TransGrid and PB's analysis, the AER agrees with PB's analysis that the most efficient option to address this identified need would be through refurbishment of the substation on its existing site (without busbar works). In presenting its preferred option to replace the substation at a new site, TransGrid did not reasonably demonstrate the efficiency and value of this option over the alternatives available.

The AER considers that a prudent and efficient TNSP in the circumstances of TransGrid would not have selected the option put forward in the capex allowance. The AER concludes and is satisfied that since the more reasonable option (in-situ refurbishment of the substation) has not been selected, a $19 million decrease to TransGrid's capex allowance more reasonably reflects the costs a prudent and efficient TNSP in the TransGrid's circumstances would require to achieve the capex objectives, as required by clause 6A.6.7(c).[134]

---

132 PB, pp. A76–86.
133 PB, pp. A76−86.
134 This is inclusive of the savings from the easement.

Beaconsfield West 132 kV GIS replacement

TransGrid's proposed expenditure for this project involves the replacement of the 132 kV gas insulated switchgear (GIS) at Beaconsfield West 132 kV due to it approaching the end of its serviceable life. The project is expected to be commissioned in 2010 and has an estimated cost of $48 million or 1.8 per cent of TransGrid's initial capex allowance.

PB's review found not all costs were included in TransGrid's options analysis, some of its option analysis was incomplete and a complete analysis could have resulted in significant changes to the NPVs of the options considered. It did, however, note that while the highest cost option had been selected, this may not have been the case had all missing costs and benefits been included in TransGrid's analysis.[135]

PB was also concerned with the lack of transparency associated with the use of certain scoping factors, in particular the design cost factor (DCF) and network cost factor (NCF), and the high construction cost associated with the project. While PB accepted there were issues associated with the site that would increase its costs it considered that the justification for the doubling of these costs lacked transparency and could not be considered reflective of an efficient and prudent TNSP. PB, therefore, recommended a –$8.1 million correction for the increase in DCF and NCF factors in the Beaconsfield West project. More broadly, PB considered there was a bias in the application of the scoping factors across TransGrid's overall capex proposal (discussed in section 3.6.8).[136]

The AER considers TransGrid's documentation clearly demonstrates that the 132 kV GIS at Beaconsfield West has significant condition problems. In particular, the AER notes that:

- the GIS has a number of design and/or manufacturing deficiencies that are particular to that equipment type
- the defect history and gas usage presented by TransGrid reflects operational and sealing problems unexpected in equipment that is not yet 30 years old.[137]

In justifying expenditure associated with this project the AER considers the omission of certain costs and benefits from TransGrid's options analysis is a significant shortcoming. The lack of adequate justification for the application of certain cost factors (discussed in section 3.6.9 and appendix B) is also a concern. These issues appear to stem from the reliance on engineering judgement which, while not a problem per se, has not been transparently applied in TransGrid's assessment process. The reliance on judgement at the expense of rigorous and transparent economic justification is a general shortcoming the AER has identified in reviewing TransGrid's capex proposal.

The AER, therefore, is not satisfied that TransGrid's proposed expenditure for the Beaconsfield West 132 kV GIS replacement reasonably reflects the efficient costs a prudent TNSP in the circumstances of TransGrid would require to achieve the capex objectives consistent with the capex criteria. Accordingly, the AER agrees with the

[135] PB, pp. A94–95.
[136] PB, pp. A97–98.
[137] PB, p. A93.

proposed amendments put forward by PB in relation to the application of the scoping factors and has made a reduction of $8.1 million to TransGrid's capex allowance as a result of this project review.

Newcastle 330 kV substation transformer replacement

TransGrid's proposed expenditure for this project involves the replacement of the existing banks of single-phase transformers at Newcastle substation as they are reaching the end of their serviceable lives. This project has a commissioning date of 2013 and an estimated cost of $19 million or 0.7 per cent of TransGrid's initial capex allowance.

TransGrid presented a range of replacement options, with their associated risk reduction scores. The options considered included the replacement of one, two or three transformers.

PB noted that TransGrid's decision to replace two transformer sets instead of replacing:[138]

- a single transformer has been made on the basis that the replacement of a single transformer set, although less expensive, does not meet TransGrid's acceptable risk score outcome for replacement or refurbishment projects
- all three transformers has been made on the basis that the two transformer replacement option meets TransGrid's acceptable risk criterion and therefore no further expenditure is justified.

PB considered TransGrid's selection of the option to replace two transformers is based on TransGrid achieving an 'acceptable risk score', which it does not consider to be reasonable, given TransGrid's specific acceptable risk criteria and their derivation are not explicitly stated in TransGrid's policy documentation, risk assessment guidelines, or the project documentation itself.[139]

Also, PB considered the project to be prudent but it could not conclude whether the most efficient option has been selected. PB noted the single transformer replacement option is a more efficient option than replacement of two transformers (TransGrid's preferred option) and that the single transformer replacement option:[140]

- returns the highest NPV for the options presented
- mitigates the risk associated with the deteriorating condition of the transformer and provides for limited spares to serve the transformer population at the Newcastle substation.

Consequently, PB recommended a reduction of $8.4 million to TransGrid's allowance to reflect the costs associated with the single transformer replacement option. That is, PB determined that the cost of addressing the risks identified with the existing

[138] PB, pp. A103–112.
[139] PB, pp. A103–112.
[140] PB, pp. A103−112.

transformers was $10.5 million, which represents the single transformer replacement option (inclusive of risk and escalations).[141]

Based on the material presented by TransGrid and PB's analysis, the AER agrees with PB's recommendation to reduce TransGrid's capex allowance to reflect the cost of the most efficient option. While the AER notes that the Newcastle substation has significant age related condition problems, the AER agrees with PB's analysis that TransGrid has not adequately substantiated the need to undertake additional investment to improve its risk score beyond an 'acceptable' level.

The AER is therefore not satisfied that TransGrid has demonstrated the replacement of two transformers reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives consistent with the capex criteria. The AER therefore has reduced TransGrid's capex allowance by $10.5 million.

The AER considers that TransGrid's lack of transparency with respect to non-economic considerations (in this case, a reduction in risk) is a broader issue across its capex proposal which needs to be addressed, through improved option development and documentation, if these are the determining factors in it selecting one option over another, particularly where the preferred option is more expensive.

Hunter Valley – Central Coast 500 kV line easement

TransGrid's proposal indicated the growing load in the Newcastle − Sydney − Wollongong area necessitates this project and it represents an important aspect of TransGrid's strategy to address future generation developments. The project has an estimated cost of $4.2 million or around 0.2 per cent of TransGrid's initial capex allowance.[142]

Following the release of the 2008 APR, the Hunter Valley to Central Coast 500 kV transmission line project has been deferred and therefore removed from TransGrid's capex allowance for the next regulatory control period. However, TransGrid advised an addition $3.0 million is required for the strategic purchase of a Hunter Valley easement in 2014, bringing the proposed cost of this aspect of the project to $7.2 million. TransGrid noted the easement is required to support the implementation of its 500 kV ring strategy.

PB's initial review of this project raised several issues with TransGrid's option analysis. In particular, TransGrid identified but excluded a range of options and failed to provide an assessment of the timing and quantity of additional future transmission line corridors that may be required. PB also found the costs associated with the line routes unreasonable when compared with similar projects and that the property costs detailed were higher than that specified in a feasibility study. Consequently, PB recommended TransGrid's expenditure associated with this easement be reduced (by

[141] PB, pp. A103–112.

[142] TransGrid states that the timing of this work is dependent on the location of new generation developments and has therefore based their planning on the probabilistic approach presented in the ROAM report. The project appears under five scenarios and carries a 6.8 per cent probability of requiring any expenditure during the regulatory control period under consideration. TransGrid has, therefore, only included 6.8 per cent of the value of this easement in its proposed capex allowance.

$1.0 million) to $3.2 million to reflect the costs contained in TransGrid's feasibility study.[143]

In its supplementary report, PB noted TransGrid's revised easement proposal was $3.0 million higher than its initial ($4.2 million) proposal, despite a deferral of the transmission line project itself. PB acknowledged the need for strategic easements but considered TransGrid had not identified any specific changes to the easement acquisitions arising from the release of the 2008 APR. PB therefore retained the position it took under its initial assessment and recommended $3.2 million as a reasonable level of expenditure (a $4 million reduction on the updated proposal).[144]

Based on the documents provided by TransGrid and PB's analysis, the AER notes TransGrid's project documentation contains indicative costs only and that, as PB identified, there is a lack of supporting evidence to justify how these estimates have been derived. Furthermore, the AER notes PB found the costs associated with the proposed easement were not reflective of efficient and prudent investment.

Consequently, the AER is not satisfied the proposed costs are the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives in accordance with the capex criteria. The AER has therefore made an adjustment of $4.0 million and is accordingly satisfied that an allowance of $3.2 million reasonably reflects the capex criteria.

Communication – SW NSW microwave and satellite

TransGrid's proposed expenditure for this project will provide SCADA facilities at substations on the Wagga − Darlington Point system in accordance with NEMMCO's request and requirements under the NER.[145] This project costs $4.8 million or 0.2 per cent of TransGrid's initial capex allowance.

PB reviewed this project and considered it is prudent, given industry standards and NEMMCO requirements, and efficient, given that where there has been a choice of technology options available, TransGrid has chosen the least cost option.[146]

Based on PB's analysis and the documentation provided by TransGrid, the AER considers TransGrid has adequately justified the need for expenditure on this project. In particular, the AER notes:

- the NER and general industry practice require transmission substations to have SCADA facilities
- in this instance, NEMMCO requested TransGrid to undertake specific action to address communications issues in South West NSW.

The AER, therefore, is satisfied the costs associated with the project reasonably reflect those which an efficient and prudent operator in the circumstances of TransGrid would require to achieve the capex objectives in accordance with the capex criteria.

---

143 PB, pp. 122–133.
144 PB, *APR 2008 supplementary report*, pp. 24−25.
145 NER, clause 4.11.1.
146 PB, p. A63.

Non-network – business IT

Business IT is the largest expenditure category within the total non-network capex. TransGrid proposed an allowance of $96 million over the next regulatory control period, which accounts for around 3.7 per cent of TransGrid's initial capex allowance.

PB used benchmarking to assess if TransGrid's business IT proposals were in line with similar businesses and found:

- the level of TransGrid's historical and proposed IT expenditure was equivalent to the IT expenditure being incurred/expected by other businesses
- while processes and procedures were not being prescriptively followed, this had no material impact on investment decisions
- the process for establishing the cost of IT projects was sound and the proposed expenditure is efficient.

Consequently, PB did not recommend any adjustment to TransGrid's proposed IT expenditure.[147]

Based on PB's analysis and the documentation provided by TransGrid, the AER considers that the process for establishing and approving the cost of these projects is sound, the need for investment is reasonable and that the proposed expenditure is efficient. The AER is therefore satisfied that the expenditure on this program reasonably reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria. The AER, therefore, has not made any adjustments to TransGrid's proposed IT capex allowance as a result of this review.

Non-network – vehicles

Vehicle expenditure is the second largest expenditure category within non-network capex. TransGrid proposed an allowance of $31 million over the next regulatory control period, which accounts for 1.2 per cent of TransGrid's initial capital allowance.

PB's analysis found:

- the process used by TransGrid for establishing the cost of vehicle expenditure forecasts is sound
- the need for investment is reasonable
- the proposed expenditure is efficient given the degree and nature of the approvals processes.

PB therefore recommended no adjustment be made to TransGrid's vehicle expenditure.[148]

147 PB, pp. 180−181.
148 PB, p. 187.

Based on PB's analysis and the documentation provided by TransGrid, the AER considers that the process used by TransGrid for establishing and approving the cost of vehicle expenditure forecasts is sound, the need for investment is reasonable and that the proposed expenditure is efficient. The AER is therefore satisfied that TransGrid's proposed expenditure for vehicle replacements reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria. The AER, therefore, has not made any adjustment to the proposed vehicles capex allowance as a result of this review.

Project review conclusion

Overall, based on its detailed review of projects and for the reasons discussed above, the AER is not satisfied that TransGrid's proposed forecast capex allowance reasonably reflects the capex criteria and accordingly should not be approved. The AER therefore considers that a total adjustment of $77 million from the detailed project reviews will reasonably reflect the efficient costs a prudent operator in the circumstances of TransGrid would incur to achieve the capex objectives, consistent with the capex criteria.[149]

3.6.8 Extension of findings on detailed sample project reviews to remainder of the forecast capex allowance

PB's detailed review of a representative sample of TransGrid's proposed forecast capex projects identified a number of issues that it considered may be prevalent across the entire proposed forecast capex allowance. These issues include the:[150]

- inadequate or non-consideration of likely reasonable options within NPV analysis
- discretionary adjustments to unit cost benchmarks to account for project specific matters.

PB recommend further adjustments to TransGrid's proposed forecast capex allowance on the basis that unjustified discretionary adjustments to standard factors is a systematic concern. In particular, PB found a general lack of transparency in the application of the scoping factors. The review of the Beaconsfield West 132 kV GIS replacement project however allowed PB to assess the application of these factors and to estimate the likely systemic cost. This was due to the costing of the Beaconsfield West 132 kV GIS replacement project having relatively more developed (lower level) costing information which permitted the application of these factors to be clearly identified and quantified. Consequently, PB recommended a –$8.1 million correction to account for costs associated with an application of the DCF and NCF factors that was not adequately justified. The $8.1 million correction represents 0.89 per cent of the value of the reviewed projects ($909 million).[151]

PB found that if a 0.89 per cent adjustment is applied on a pro-rata basis across the un-reviewed capital works portfolio of TransGrid's initial capex proposal, a

[149] The total adjustment of $77 million does not include adjustments associated with identified systemic issues (section 3.6.8) or adjustments from the review of TransGrid's replacement capex (section 3.6.9).
[150] PB, p. 129.
[151] PB, *APR 2008 supplementary report*, pp. 29–30.

correction of –$14 million would result. Following the release of the 2008 APR, and TransGrid's subsequent reduction in its capex program, this correction was however, reduced to $13 million.[152]

AER considerations

The sample of TransGrid's projects subject to detailed review was intended to be representative of the total forecast capex program and indicative of the issues likely to be encountered across TransGrid's entire proposed forecast capex allowance. This provides the basis for making a top down adjustment which the AER considers is appropriate in determining whether it is satisfied on the whole that TransGrid's proposed forecast capex allowance reasonably reflects the capex criteria.

The lack of transparency in the application of scoping factors was not limited to the Beaconsfield West project. In particular, the AER notes that PB found discrepancies in the factors applied in the detail costing associated with options assessed in the:

- Newcastle/Waratah/Tomago area feasibility study[153]
- Sydney West – Holroyd – Chullora Overall feasibility study[154]
- Dumaresq − Lismore 330 kV line development project, where PB recommended an adjustment of $4.0 million due to issues associated with the application of the scoping factors.

The AER notes PB's analysis which stated that while the majority of the other projects subject to detailed project review were not adjusted in a similar manner (0.89 per cent), PB's detailed review of other projects did permit it to assess the overarching cost efficiency of those projects and recommend appropriate 'bottom up' adjustments. This explains why PB's extrapolation of the scoping factor is applied only to unreviewed capex projects. The AER considers that the approach PB has adopted in extending the findings of the detailed sample project reviews to the remainder of the forecast capex allowance is reasonable.

The AER also notes that TransGrid's capex estimating database manual allows for the standard factors to be altered if the project investigation identifies that the standard factors are not appropriate. As the weight of each factor can be adjusted on a discretionary basis for particular projects the capital estimation process can lack transparency, consistency and auditability. The AER therefore considers TransGrid's process for adjusting standard factors creates an environment where the scope for systemic overestimation of proposed capex project costs is present.

Conclusion

Based on PB's analysis, TransGrid's documentation and the considerations outlined above, the AER is not satisfied that TransGrid's proposed capex allowance reasonably reflects the capex criteria. In particular, the AER is not satisfied that TransGrid's proposed expenditure reasonably reflects efficient costs of achieving the capex objectives as it is based on a potential overestimation of certain cost factors.

---

152 PB, *APR 2008 supplementary report*, p. 29.
153 TransGrid, *Feasibility Study Report FS PSR 199*, Revision 0 June 2008, p. 58.
154 TransGrid, *Feasibility Study Report FS PSR 12_18_25,* Revision 0 June 2008, p. 111.

The scope for this overestimation and the lack of justification for cost factor adjustments has been identified in some of TransGrid's documentation and stems from a cost estimation procedure that permits a systemic over estimation of capex project costings to occur. In this situation, clauses 6A.6.7(d) and 6A.14.1(2) require that the AER must not accept TransGrid's proposal and must instead substitute an estimate which it is satisfied will reasonably reflect the capex criteria. To this end, the AER has concluded that it will apply a $13 million reduction to TransGrid's proposed capex allowance, as this reasonably reflects the capex criteria.

3.6.9 Replacement programs

TransGrid proposal

TransGrid proposed to spend $493 million or 19 per cent of its capex allowance on the replacement of its existing assets. It proposed to replace assets across the various category classes, which include:[155]

- communication & control
- protection & metering
- substation – circuit breakers
- substation – instrument transformers
- substation − plant & equipment
- substation − security
- substation − civil work
- transformer replacement
- transmission lines − minor upgrades
- transmission lines − wood poles.

TransGrid determines replacement by considering (amongst other factors), the condition of its assets, ongoing serviceability, NER requirements, safety and the environment in which it operates. The output from its assessment forms the input into the Network asset management plans and these, in turn, permit short-term maintenance to be managed while taking long-term issues into consideration.[156]

Consultant review

Due to the large number of programs associated with asset replacement works, PB reviewed a typical component program from each category to assess the prudence and efficiency of the overall capex. The total value of the reviewed programs was $74 million or 46 per cent of the total proposed replacement capex.

[155] PB, p. A126.
[156] TransGrid, *Revenue proposal*, p. 64.

Based on its assessment PB recommended the following adjustments to TransGrid's forecast replacement capex as shown in table 3.14:

- a reduction of $4.4 million for instrument transformers replacement programs, to make allowance for the replaced instrument transformers to be re-used
- a reduction of $1.2 million for transmission lines replacement programs, to cover the reduction in scope associated with the deferral of approximately half of the structure replacements to future regulatory control periods.

Table 3.14: PB's recommendations – replacement programs ($m, 2007−08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Instrument transformer adjustment	–0.7	–0.9	–1.0	–0.9	–0.9	–4.4
Transmission line adjustment	–0.1	–1.1	–	–	–	–1.2
Total	–0.8	–2.0	–1.0	–0.9	–0.9	–5.6

Source: PB, p. 128.

AER considerations

The AER agrees with PB's analysis that TransGrid's proposed program for pole replacement (transmission line adjustment) is excessive. Significantly, the AER notes PB's finding that TransGrid could defer approximately half of the pole replacements to future regulatory control periods. Consequently, the AER agrees with PB's recommendation that this aspect of the replacement program be reduced by $1.2 million.

The AER also agrees with PB's finding that TransGrid's proposed replacement program for instrument transformers does not adequately assess the reasonable options that have been identified for asset replacement. Importantly, the AER notes that TransGrid's selection of the preferred option is often based on factors other than those detailed in the options comparison documentation, typically resulting in additional cost or scope that has not been included in the options costing. To address these issues, PB recommended a reduction in the substation replacement program of $4.4 million.

Based on the information detailed above, TransGrid's documentation and PB's analysis, the AER is not satisfied the proposed costs are the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, in accordance with the capex criteria. The estimate the AER is satisfied reasonably reflects the capex criteria is $5.6 million less than which TransGrid is seeking in its capex allowance. The AER has, therefore, removed $5.6 million from TransGrid's allowance.

3.6.10 Cost accumulation process

This section examines whether TransGrid's cost accumulation process provides a reasonable basis for estimating the cost and profile of its proposed capex over the next regulatory control period. It discusses the process TransGrid has employed to develop

its base project cost estimates and how it has converted them into a capex profile for the next regulatory control period. Specifically, it reviews the base planning objects used to develop the project costs, input escalators for land and easements, labour and non-labour (materials) construction costs, and the application of a cost estimation risk factor. The AER considers the basis on which TransGrid has estimated the costs and profiles of its proposed forecast capex are relevant issues in determining whether it is satisfied TransGrid's proposed forecast capex reasonably reflects the capex criteria. In particular one capex criterion relates to a realistic expectation of the input costs incurred to achieve the capex objectives.

TransGrid has undertaken the following cost accumulation process in developing the annual capex profile for its network projects over the next regulatory control period:

- it estimated the capital costs for each project, which included the application of scoping factors
- it applied component 'S-curves' to estimate timing of expenditure associated with different types of projects
- it applied CPI and real price increases (escalators) for labour, materials, producer margins and land costs in project estimates
- it applied a risk factor to each project.

Base unit costs

A common process for establishing the cost of a project is to build up an estimate from individual elements and to reach a total cost for the project, commonly known as a building block approach.

TransGrid proposal

TransGrid provided details and costs for the major items of transmission equipment required to complete the projects that were reviewed by PB. The costs and scope of all remaining projects included in the forecast capital works program were also provided at a summary level.[157]

Consultant review

PB examined the costs TransGrid used in its planning process and compared those costs to its benchmarks that it had derived from published sources and its own cost database. PB considered specialist transmission project type costs within 20 per cent of its benchmark costs were reasonable.[158]

PB found the following items had costs that were lower or about the same as its benchmarks:[159]

- instrument transformers
- circuit breakers

[157] PB, p. 63.
[158] PB, p. 65.
[159] PB, p. 68.

- transformers up to 120 MVA.

PB also found the unit costs for large power transformers and transmission lines were at the upper limit of the expected range, but not unreasonable relative to the benchmark. [160]

Further, PB found that control-room building costs were significantly higher than its benchmark (more than 20 per cent higher) but on detailed analysis of the scope of the work found this was reasonable relative to other TNSPs.[161]

Overall, PB was satisfied that the process used by TransGrid to determine project costs is reasonable.

AER considerations

The base unit costs used by TransGrid underpin the majority of its network project cost estimates and are essential for determining the cost of different components used in the construction of switchyard bays, substations and transmission lines.

The AER notes PB reviewed the base unit costs and was generally satisfied that the process used by TransGrid to determine project costs is reasonable. The AER also notes that PB reviewed the unit costs of a number of objects to determine their accuracy and concluded that the base unit costs used by TransGrid represent reasonable costs for the described objects.

The AER accepts PB's advice that TransGrid's base unit costs objects are reasonable and provide an appropriate basis to estimate the cost of its forecast capex program. In particular, the AER notes that the majority of costs were within 20 per cent of PB's benchmark costs, and where this did not occur the rationale provided for this difference was reasonable. Accordingly, the AER is satisfied that TransGrid's proposed base unit costs reflect a realistic expectation of the efficient cost inputs required to achieve the capex objectives, consistent with the capex criteria. The AER, however, notes that there are issues associated with TransGrid's application of scoping factors and that this has resulted in some unsubstantiated increases in the costs associated with its proposed forecast capex projects (section 3.6.8).

S-curves

TransGrid proposal

TransGrid has developed its component S-curves through 'work shopping' and experience in lieu of dependence on detailed historical data.[162]

Consultant review

PB considered the use of S-curves derived through work shopping and experience resulted in capex profiles that are less transparent and potentially highly sensitive to the changes in the input parameters derived from opinion.

However, through comparison with actual historical expenditure profiles and other businesses, PB concluded that TransGrid's profiles are generally representative of

[160] PB, p. 68.
[161] PB, p. 67.
[162] PB, pp. 105–110.

typical projects and conservative in the context that expenditure is timed to occur at later dates.

On this basis, PB found the S-curves applied in TransGrid's capex estimation process are reasonable and recommended no changes to them.[163]

AER considerations

The AER notes that PB found TransGrid's S-curves are generally representative of typical projects and conservative in the context that expenditure is timed to occur at later dates.

Based on the information received from TransGrid and PB's advice, the AER considers that TransGrid's profiles are generally representative of typical projects. The AER, therefore, accepts PB's advice that TransGrid's proposed S-curves are reasonable and is satisfied they are consistent with the capex criteria.

Real cost escalators

At a general level, the AER has an obligation to provide businesses with a reasonable opportunity to recover efficient costs associated with their ongoing operation. In recent decisions the AER has therefore permitted capex allowances to be escalated in real terms for input cost increases above that associated with CPI.[164]

Given there is no futures market for the procurement and installation of electrical equipment (e.g. transformers, switchgear), in previous decisions cost escalations have been estimated with reference to the expected growth in key input 'cost factors' such as copper, aluminium, crude oil, construction costs, electricity, gas and water (EGW) sector labour costs and land/easement costs. Other inputs, such as steel, were escalated at CPI.

TransGrid proposal

PB considered the approach adopted by CEG in determining its copper and aluminium forecast escalators to be reasonable. PB, therefore, did not recommend any changes to the base material escalators. Similarly, PB found that TransGrid's proposed escalations for land and construction cost factors were reasonable and also left them unchanged.[165]

In terms of TransGrid's producer's margin escalation, PB considered there was sufficient anecdotal evidence to support the implicit assumption that electrical equipment producers are currently near full production capacity, have been for some time, and are likely to remain at or near full capacity for some time to come. PB, therefore, accepted the underlying basis for the CEG producer's margin forecast. PB was, however, concerned that the producer's margin escalation for 2010 and 2011 was

---

163 PB, p. 110.

164 AER, *Decision – Powerlink Queensland transmission network revenue cap 2007–08 to 2011−12*, 14 June 2007, pp. 60−70;
AER, *Draft Decision – SP AusNet transmission determination 2008–09 to 2013−14*, 31 August 2007, pp. 87−91, 316−331;
AER, *Final Decision – ElectraNet transmission determination 2008–-09 to 2012−13*, 11 April 2008, pp. 29−48.

165 PB, pp. 98, 101.

based only on one forecast (Prysmian EBIT), rather than the averaging approach that had been used in earlier years of the forecast. Consequently, PB determined this reliance on one source was not reasonable, as this would significantly overstate the forecast average industry margin growth, and recommended that that no real increase in margins be applied beyond 2009.[166]

As a consequence of these findings, PB concluded that the escalation allowance was not reasonable and should be reduced by $9.4 million to reflect the expenditure that an efficient TNSP would require.[167]

TransGrid engaged CEG to develop real cost escalation forecasts for its capex proposal in the next regulatory control period.[168] For the most part, CEG maintained the methodology it used to forecast aluminium, copper, crude oil prices and construction costs based on the report it prepared for ElectraNet, including its proposed adjustments to the Consensus Economics aluminium and copper price forecasts (see appendix C for more information).

However, CEG also proposed a number of additional cost factors not previously applied to the overall cost escalation methodology, including:

- variances in prices charged by equipment manufacturers to reflect their market power (producer margins)
- the proportion of general labour costs used in the manufacture of electrical equipment (producer labour costs)
- indirect general labour costs associated with the processing of raw materials (e.g. steel).

TransGrid's proposed escalators are detailed in table 3.15. Further information on TransGrid's proposed escalators is set out in appendix C.

166 PB, pp. 98-99.
167 PB, p. 101.
168 CEG, *Escalation factors affecting expenditure forecasts: a report for NSW electricity businesses*, April 2008.

Table 3.15: TransGrid's proposed escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Land	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Copper	–0.4	–3.7	–6.3	–4.2	–2.8	–3.1	–3.1
Aluminium	–5.6	3.5	–0.5	–0.2	0.3	0.0	0.0
Crude oil	24.4	12.3	–3.8	–1.3	–0.5	–2.0	–0.9
Steel	0.2	0.1	0.3	0.2	0.2	0.2	0.2
EGW (NSW) wages	3.1	3.6	3.9	1.9	2.8	3.5	3.7
Construction costs	2.3	2.1	0.9	0.7	1.1	1.9	2.6
Wages general	1.8	1.6	2.4	1.9	1.8	2.0	2.0
Producer's margin	9.5	5.4	6.1	7.6	0.0	0.0	0.0

Source: CEG, *Escalation factors affecting expenditure forecasts*, April 2008, p. 2.

AER considerations

In assessing the escalators recommended by CEG and used by TransGrid, the AER considers that its conclusions from the recent ElectraNet decision are still applicable with respect to the methodology used for estimating each of these cost escalators (i.e. copper, aluminium and crude oil). In most cases, CEG has not presented any new compelling evidence justifying a departure from the approach previously accepted by the AER.

At a fundamental level, the AER has concerns with the additional cost factors mentioned above that do not meet the underlying objective for inclusion in forecast costs under clause 6A.6.7(c) of the NER.

In particular, the AER considers that given the inherent uncertainties around the existence of and estimation of real movements in these cost factors, further departures from CPI are not warranted. It is important to note that the AER accepts that such costs are likely to be included in base (unit) cost estimates. However, what is questionable is the extent to which real growth is expected and whether it can be forecast on a reasonable basis.

More generally, the AER considers that these additional cost factors represent a departure from the AER's intention to account for the effects of the recent commodities boom and skilled labour shortages in Australia. The effect of their inclusion would be to weaken the influence of commodities prices and the symmetry of the cost escalators envisaged by the AER. Moreover, they represent a move towards compensation for all input costs at a fine level of detail and go beyond the AER's general obligation to provide businesses a reasonable opportunity to recover efficient costs, and in this sense are also inconsistent with the incentive frameworks for capex.

For the majority of the proposed escalators, the AER has considered that some methodological elements of the proposed forecast cost increases are inappropriate, and has also considered more recently published data in making this draft decision, which will be updated again for the final decision and determination.

The AER considers TransGrid's proposed escalators are not, with the exception of land, reasonable. It has instead proposed an alternative set of escalators that it is satisfied reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria. The AER's proposed escalators are detailed in table 3.16.

Further information on the issues the AER considered in making its decisions on these escalators is available in appendix C.

Table 3.16: AER's conclusion on real escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Land	4.1	4.1	4.1	4.1	4.1	4.1	4.1
Copper	–6.3	–13.5	0.3	1.4	–5.6	–6.3	–7.0
Aluminium	–6.3	–7.0	7.5	9.3	–0.8	–1.3	–1.6
Crude oil	43.5	–13.4	1.5	1.7	–0.1	–0.6	–0.1
Steel	53.8	–3.7	0.6	–3.4	–2.5	–3.0	–3.4
EGW (NSW) wages	0.5	2.8	3.9	3.4	3.0	2.8	2.1
Construction costs	–0.3	–1.9	0.4	1.2	1.1	1.0	1.0
Wages general	0.6	1.0	1.1	0.7	0.7	0.8	0.6
Producer's margin	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Application of escalators to the capex program

TransGrid proposal

TransGrid's approach to escalating the forecast capex in its model is based on applying the proportion (or weighting) of each of the 14 components that have been forecast as a percentage of the forecast capex program.

The weighting for each component for each year of the next regulatory control period is detailed in table 3.17.

Table 3.17: TransGrid proposed escalation weightings (per cent)

Component	Weighting	Aluminium	Copper	Steel	Oil	EGW Wages	Wages General	Construction Costs	Producer's Margin	Other
EGW Wages	15.65					100				
Structures & Fabricated Steel	1.34			7				93		
Primary Plant	13.28		6						10	84
Secondary Systems	6.02								10	90
Transformers	9.46		10	9	4				10	67
Buildings	1.46							100		
Civil Construction	9.57							100		
Electrical Construction	1.66							100		
Transmission Towers	12.99			9				91		
Aluminium Conductor	5.67	60		5					10	25
Concrete Poles	2.01							42		58
Copper Cable	12.03	1	19	2	2	9	4	46	4	11
Wages General	4.75						100			
Miscellaneous Materials	4.12									100
Proportion of Capital Expenditure		3.5	4.0	2.6	0.6	16.7	5.2	32.1	3.9	30.9

Source: PB, p. 102.

Consultant review

PB reviewed TransGrid's proposed escalation factors and weightings and recommended adjustments to:[169]

- the producer's margin escalator
- the weighting applied to the material component of steelwork construction to more accurately reflect the larger steel component of various pieces of infrastructure (an adjustment that TransGrid agreed was reasonable and which it amended during the review process – see section 3.6.6).

[169] PB, p. 105.

PB's recommended changes to TransGrid's proposed escalation factors and weightings are detailed in table 3.18.

Table 3.18: PB's proposed base cost escalation weightings (per cent)

Component	Weighting	Aluminium	Copper	Steel	Oil	EGW Wages	Wages General	Construction Costs	Producer's Margin	Other
EGW Wages	15.65					100				
Structures and Fabricated Steel	1.34			11				89		
Primary Plant	13.28		6						10	84
Secondary Systems	6.02								10	90
Transformers	9.46		10	9	4				10	67
Buildings	1.46							100		
Civil Construction	9.57							100		
Electrical Construction	1.66							100		
Transmission Towers	12.99			11				89		
Aluminium Conductor	5.67	60		5					10	25
Concrete Poles	2.01							42		58
Copper Cable	12.03	1	19	2	2	9	4	46	4	11
Wages General	4.75						100			
Miscellaneous Materials	4.12									100

Source: PB, p. 104.

PB requested that TransGrid recalculate its proposed escalations for steel work contruction using the weightings outlined in table 3.18. TransGrid advised PB the total value associated with these adjustments is a reduction in the escalation allowance of $0.8 million.[170] [171]

PB also noted TransGrid applied its escalation factors on the basis of the aggregate weighting by component of the 5 year capital works program and that this was not appropriate as project work varied substantially from year to year. PB requested

[170] This change was agreed by TransGrid.
[171] PB, p. 103.

TransGrid to examine the impact of applying annual escalators to its forecast capital works portfolio, which was examined by PB, and resulted in a recommended reduction of $3.6 million in capex over the next regulatory control period.[172] PB's review of TransGrid's escalators is also detailed in appendix C.

2008 APR update

Following the release of the APR 2008, PB re-examined its recommendations with regard to escalation factors and recommended a number of amendments. In particular, it recommended that its two recommended adjustments in the initial proposal, which totalled $13 million, be reduced to $12.4 million. This reduction is due to:[173]

- TransGrid having applied slightly lower weightings to its steel component in its revised modelling. When this change is considered in combination with PB's recommended change to the producer's margin escalator this results in the $9.4 million reduction being replaced by a $8.9 million reduction

- a reduction associated with the estimate associated with the annual application of escalators rather than the use of a weighted five-yearly application. Under the 2008 APR, PB found this resulted in the $3.6 million being reduced to $3.5 million due to lower capex requirements in the next regulatory control period.

AER considerations

The AER has considered TransGrid's application of real cost escalators to its capex program, and agrees with the change in the proportion of steel in the steelwork and transmission towers. The AER considers this would result in a more accurate reflection of the inputs used in these expenditure components.

The AER also considers that using the same set of weightings for each year of its capex program is likely to distort TransGrid's cost estimates. As the type of projects undertaken in each year vary, so to will the particular proportions of various inputs used in its capex program. Accordingly the weighting of escalation factors should reflect the year to year variability of TransGrid's capex program as this more reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria.

The AER has requested TransGrid to remodel the impact of using annual weightings based on the capex allowance determined in this draft decision. This has resulted in an adjustment of $4.7 million, which compares to PB's recommended adjustment of $3.5 million.

The AER has also identified a minor error in TransGrid's application of escalators in its capex modelling. TransGrid's base project cost estimates were developed in June 2007 and were therefore in 2006–07 dollar terms. Two years' escalation was required to convert the base 2006–07 project cost estimates into end of 2008–09 dollar terms—the post-tax revenue model (PTRM) requires capex to be entered in those dollar terms. In order to apply the real input cost escalators beyond 2008–09 for capex to be

[172] PB, p. 105.
[173] PB, *APR 2008 supplementary report*, pp. 26−27.

incurred over the next regulatory control period, the project cost estimates must be escalated by the relevant year's real cumulative escalator.

The AER identified that TransGrid has calculated the real cumulative input cost escalators based on capex being incurred at the end of the year over the next regulatory control period. However, the PTRM assumes that capex is incurred in the middle of the year. The real cumulative input cost escalators employed over the next regulatory control period should therefore be applied in a manner that is consistent with the capex timing assumptions in the PTRM to ensure appropriate compensation is provided. Accordingly, the AER requires TransGrid to adjust the application of the real cumulative input cost escalators to recognise the half-year capex timing assumption.

Overall, for the reasons discussed above, the AER is not satisfied the application of the materials cost escalators as proposed by TransGrid reasonably reflects the efficient costs a prudent TNSP in TransGrid's circumstances would require to achieve the capex objectives, as required by clause 6A.6.7(c). The AER has requested TransGrid to re-calculate its expenditure program using the AER's approved escalators as well as the adjustments to its application method as outlined above. The revised amounts are illustrated in table 3.19.

Cost estimation risk factor

TransGrid proposal

TransGrid, in consultation with Evans & Peck, assessed the risks associated with TransGrid's capital works program for the next regulatory control period.[174] This involved a framework and process similar to the approach adopted by ElectraNet, Powerlink, and SP AusNet as part of their previous revenue reviews.

In general terms, the process to arrive at the risk adjustment factors involved a workshop of stakeholders within TransGrid who are directly involved in the estimating and management of network capital works projects. A range of representative projects were selected to focus the group on the risks that drive the variation between the concept estimate and the out-turn cost.[175]

In undertaking this assessment, Evans & Peck first focused on the variation that can occur in the project costs on a detailed line item basis. TransGrid's expert group identified the cost variance parameters from which a variance model was then developed for each major line item. This information was then used to assess the inherent risk and associated risk profiles for the project cost components for each of the selected projects.

The cost estimation risk analysis resulted in an increase of the base estimates of 158 (or 87 per cent of all) network projects by $77 million[176], through the application of ratios of risk adjusted out-turn cost to base estimates of between 1.02 and 1.07, depending on the nature of the project.[177]

---

174 TransGrid, *Revenue proposal*, p. 71.
175 TransGrid, *Revenue proposal*, p. 71.
176 PB, p. 111
177 TransGrid, *Revenue proposal*, p. 71..

Consultant review

PB found TransGrid had experienced challenges in ensuring the estimates of cost variance used in the risk analysis did not include costs variations that were captured through other means. That is, the estimates included variations in cost due to escalation of labour and materials.

As the risk allowance is also escalated by the material and labour escalators, the resulting figures double counted the impact of labour and material escalation on the risk portion of project costs. To remove the variance and the escalation of that variance PB recommended the removal of $11.1 million from the $77 million risk allowance.[178]

To ensure that manageable risks are managed appropriately PB also considered application of the P50[179] value of risk rather than the mean (which TransGrid used for pragmatic reasons) is appropriate to ensure a reasonable allocation of risk between TransGrid and its customers. This resulted in a further reduction of $0.6 million.

PB concluded that the risk allowance overall should be reduced by $11.7 million.[180]

2008 APR update

Following the release of the APR 2008, PB re-examined its recommendations with regard to the risk allowance and recommended a number of amendments. In particular, it recommended that the three recommended adjustments in the initial proposal, which totalled $11.7 million, be reduced to $11.4 million. This is due to:[181]

- a reduction in the allowance associated with the double counting of risk factors. Under TransGrid's initial proposal PB recommended the total risk allowance of $77 million be reduced by $10 million (i.e. reduced to $67 million) to remove the double counting. Under the 2008 APR, the total risk allowance of $73 million is reduced by $9.7 million (i.e. reduced to $63 million) to remove the double counting

- a reduction to take into account a further adjustment to remove escalation from the risk allowance. Recalculating this resulted in a risk reduction of $8.1 million (down from $8.7 million)

- the retention of the $0.6 million adjustment associated with TransGrid's use of the mean rather than P50—noting that under the new capex portfolio the change with this recommendation is not materially different to that originally proposed by PB.

178 PB, p. 114.

179 The P50 value represents a reasonable allocation of risk between the service provider and its customers—it represents an even allocation of risk between the two parties. The mean value actually represents the expected outcome. In this case, Evan & Peck estimated that the mean has a marginally higher global risk profile (3.32 per cent) to that associated with P50 (3.30 per cent).

180 PB, p. 114.

181 PB, *APR 2008 supplementary report*, pp. 27−29.

AER considerations

In previous decisions the AER has generally accepted the modelling approach applied by Evans and Peck.[182] The AER's view is that the process of 'risk workshops' does not, however, lend itself to transparent assessment and has produced bias in expenditure adjustments. This is a recurring concern to the AER. For example, in the SP AusNet determination the AER highlighted its concerns with data derived from risk workshops as it can be based on:

> … asymmetric risk assumptions for almost all events, with substantial variances in some cases. The AER expressed a similar concern regarding this particular element of E&P's [Evans and Peck] risk modelling for ElectraNet, and specifically that the inputs for its modelling were obtained through a 'risk workshop' with the TNSP, and without any systematic evaluation of risks on actual cost outcomes by more objective measures.[183]

The AER shares PB's concern that TransGrid has failed to ensure that the estimates of cost variance set at the workshops did not include costs that are captured elsewhere. That is, there was a lack of transparency in the factors considered at the workshops that suggested there was scope for the variances to reflect costs that were captured in other cost factors, including labour and materials escalators.

The AER also agrees with PB's finding that it is appropriate for TransGrid to apply a risk adjustment associated with the P50 risk profile, as this will reflect an equal sharing between TransGrid and its customers of those risks that are not reasonably manageable by TransGrid. The AER does not think it reasonable that cost variations that are captured through other means, or that are within TransGrid's control should be captured in risk profiles and consequently inflate the costs associated with its capex program.

On balance, given the information provided by TransGrid and PB's analysis, the AER considers that the costs associated with risk included in TransGrid's proposal are unreasonable. The AER is not satisfied TransGrid's proposal in this regard reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria. Rather, the estimate the AER is satisfied reasonably reflects the capex criteria is $11.4 million less than that which TransGrid is seeking. The AER has therefore removed this amount from TransGrid's risk allowance to reflect the efficient costs that should be incurred.

AER conclusions

In summary, the AER's conclusions with respect to TransGrid's cost accumulation process are:

- TransGrid's proposed base unit costs are reasonable and provide an appropriate basis to estimate the costs of its forecast capex program.
- TransGrid's application of scoping factors is not reasonable for the purposes of estimating forecast capex.

---

[182] AER, *Decision – Powerlink revenue cap*; AER, *Draft Decision – SP AusNet transmission determination*, AER, *Final Decision – ElectraNet transmission determination*.

[183] AER, *Draft decision – SP AusNet transmission determination*, p. 76.

- TransGrid's S-curves are reasonable for the purposes of developing the capex profile of different projects.
- TransGrid's recommended land and easement real escalator of 4.1 per cent per annum is appropriate for the purposes of estimating forecast land value growth.
- TransGrid's proposed producer's margin escalator is not appropriate for the purpose of estimating forecast electricity infrastructure equipment cost growth and should be substituted with a producer's margin escalation of zero per cent (meaning the producer's margin moves in line with CPI).
- TransGrid's proposed EGW labour escalation rates are not reasonable for the purposes of estimating forecast wages growth and should be substituted with an average EGW labour real escalation rate of 3 per cent.
- TransGrid's proposed general labour escalation rates are not reasonable for the purposes of estimating forecast wages growth and should be substituted with an average general labour escalation rate of 0.78 per cent.
- TransGrid's recommended materials cost escalators are not appropriate for the purposes of estimating forecast electricity infrastructure equipment cost growth and should be substituted with an alternative set of escalators.
- TransGrid's proposed cost estimation risk factor is unreasonable for the purposes of developing the capex estimates and has reduced this accordingly.
- Escalators should be applied on an annual basis to reflect the different composition of the capex works that are to be undertaken each year, rather than on a fixed, 5-year average level over the next regulatory control period.

Table 3.19 sets out the overall effect of the AER's adjustments, which result in a reduction of $89 million in TransGrid's proposed forecast capex allowance. The AER is satisfied this reduction reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require in relation to its cost accumulation methods to achieve the capex objectives, as required by clause 6A.6.7(c).

Table 3.19: AER's conclusion on TransGrid's cost accumulation methods ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Unit costs	–	–	–	–	–	–
S-curves	–	–	–	–	–	–
Escalators	–6.4	–9.1	–12.6	–16.9	–15.0	–59.9
Cost estimation risks	–2.3	–2.0	–2.6	–2.5	–1.8	–11.4
Application of annual escalators	0.6	–0.1	–6.3	–2.4	3.5	–4.7
Application of scoping factors	–2.8	–2.4	–3.0	–2.9	–2.2	–13.3
Total	–10.9	–13.6	–24.5	–24.7	–15.5	–89.3

Note: Totals may not add up due to rounding.

3.6.11 Contingent projects

This section sets out the AER's consideration of TransGrid's proposed contingent projects and any other projects from the capex allowance that should be treated as contingent projects.

Regulatory requirements

The AER is required to assess contingent projects in accordance with clause 6A.8.1 of the NER. To accept a proposed contingent project the AER must be satisfied that:

- the project is reasonably required to be undertaken to achieve the capex objectives
- the proposed contingent capex is not otherwise provided in the capex allowance and reasonably reflects the capex criteria
- the indicative cost exceeds either $10 million or 5 per cent of the maximum allowed revenue (MAR) for the first year of the regulatory control period (cost threshold)
- the information provided in relation to contingent projects complies with the AER's submission guidelines made under clause 6A.10.2
- the proposed trigger event is appropriate.

Clause 6A.8.2 of the NER sets out the requirements to amend a revenue determination where a trigger event for a contingent project identified in that revenue determination occurs.

TransGrid proposal

TransGrid proposed that 18 projects with a total indicative cost of $2.3 billion be included as contingent projects in its initial revenue determination. This increased to 19 projects following the release of the 2008 APR. TransGrid stated that its proposed

MAR for the first year of the next regulatory control period is $670 million. Five per cent of the MAR is $33 million, which makes this amount the cost threshold for contingent projects in TransGrid's revenue proposal. Table 3.20 details TransGrid's initial proposed contingent projects.

Table 3.20: List of contingent projects ($m, 2007–08)

Project	Capital cost
Kemps Creek – Liverpool 330 kV line – Undergrounding of all or part of the proposed connection	$108
Darlington – Balranald system upgrade 275 kV	$51
Development of a second 500 kV link	$330
New 500/330 kV substation at Richmond Vale	$80
Yass to Wagga 500 kV double circuit transmission line	$329
Liddell – Tamworth 330 kV	$163
Tamworth – Armidale 330 kV line	$130
QNI upgrade – series compensator	$60–120
Interconnection development from Victoria	$33
Bannaby – Yass reinforcement	$45
CBD supply – cable into the CBD	$650
Gadara/Tumut load area support	$54
Williamsdale – Cooma 3rd circuit	$40
Orange 330 kV substation	$63
330 kV substation at Williamsdale	$35
SVC	$40
Reactive support at Bayswater	$36
System protection scheme	–

Source: TransGrid, *Revenue proposal*, Appendix I, pp. 1–10.

Submissions

The EUAA suggested TransGrid's proposed contingent projects were excessive and their need was not adequately substantiated.[184]

Consultant review

PB was required to assess whether TransGrid's proposed contingent projects met the contingent project criteria and whether there were any projects in the capex allowance that would be more appropriately classified as contingent.

PB noted that part of the criteria for contingent projects under the NER is that the trigger event must:[185]

[184] EUAA, pp. 4, 21–22.
[185] PB, pp. 133–134.

- be reasonably specific and capable of objective verification
- generate increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the transmission network as a whole
- be probable during the next regulatory control period but not sufficiently certain that the event will occur in the next regulatory control period.

Based on its review of TransGrid's initial and updated contingent project lists, PB generally found the trigger event was not sufficiently or specifically defined outside the bounds of the scenario analysis adopted by TransGrid. Table 3.21 summarises the proposed contingent projects PB considered did not meet the conditions required for a contingent project.

Table 3.21: Proposed contingent project not recommended for inclusion ($m, 2007–08)

Project	Concern/Issue	Cost
Development of a second 500 kV link	The proposed trigger event not adequately defined	$330
QNI upgrade – series compensator	The proposed expenditure does not reasonably reflect the capital expenditure criteria and the proposed trigger event is not adequately defined	$120
Interconnection development from Victoria	The proposed expenditure does not exceed the required limit proposed and the proposed trigger event is not adequately defined	$33
CBD supply – cable into the CBD	The proposed expenditure does not reasonably reflect the capital expenditure criteria and the proposed trigger event is not adequately defined	$650
Gadara/Tumut load area support	The proposed expenditure does not reasonably reflect the capital expenditure criteria and proposed trigger event not adequately defined	$54
Orange 330 kV substation	The proposed expenditure does not reasonably reflect the capital expenditure criteria and the proposed trigger event is not adequately defined	$63
330 kV substation at Williamsdale	The proposed expenditure is otherwise provided for and it does not reasonably reflect the capital expenditure criteria	$35
SVC	The proposed expenditure is otherwise provided for and the proposed trigger event is not adequately defined	$40
Reactive support at Bayswater	The proposed expenditure does not reasonably reflect the capital expenditure criteria and the proposed trigger event is not adequately defined	$36
System protection scheme	The proposed expenditure is otherwise provided for and it does not reasonably reflecting the capital expenditure criteria, and proposed trigger event is not adequately defined	–

Source: PB, pp. 136−139.

PB therefore recommended that only nine of TransGrid's proposed contingent projects be included as contingent projects. Table 3.22 details those projects recommended to be included as contingent projects.

Table 3.22: PB contingent project recommendations ($m, 2007–08)

Project	Trigger	Cost
Kemps Creek − Liverpool 330 kV line— Undergrounding of all or part of the proposed connection	1. A determination by the environmental consent authority that inclusion of a specific amount of undergrounding is required for the project to be approved, and 2. The project with undergrounding satisfies the Regulatory Test. The capital submission includes the cost of the overhead line. The contingent project cost is the differential cost of undergrounding the cable over and above the cost of installing the overhead line	$108
Hunter Valley to Coast 500 kV development of a double circuit 500 kV line development	1. A northern or western NSW power station development exceeding 400 MW or 2. A development of the Queensland interconnection enabling an increase in NSW import capability exceeding 400 MW or 3. A spot load development in the Newcastle area exceeding 200 MW. and TransGrid is directed to undertake a regulatory test for a line development under the Last Resort Planning Power provisions of the NER.	$270
Darlington − Balranald system upgrade 275 kV	1. NSW Government directs TransGrid to upgrade this transmission line to improve their greenhouse gas emissions.	$51
Yass to Wagga 500 kV double circuit transmission line	1. A set of coal-fired or gas-fired generators, with a combined output exceeding 200 MW, is committed for connection to the network in the following southern areas of the NSW system south of the Yass/Canberra area: - Wagga - Jindera - Buronga/Broken Hill area - Snowy area or 2. The Victorian export capability to Snowy and NSW is increased by 200 MW above the present capability. and The generation development or increased export capability causes a network limitation to arise on the system between Murray and Upper Tumut/Lower Tumut and between Upper Tumut/Lower Tumut and Yass/Canberra.	$329
Liddell − Tamworth 330 kV	1. A set of coal-fired or gas-fired generators, with a combined output exceeding 600 MW (or wind farm developments that provide the equivalent output at time of high NSW load), is committed for connection to the network in NSW in the Tamworth or Armidale area or 2. The NSW import capability from Queensland is increased by 600 MW above the present capability or 3. The NSW export capability to Queensland is increased by	$163

	200 MW above the present capability. and The generation development or increased interconnection capability causes a network limitation to arise on the system between Liddell and Tamworth.	
Tamworth − Armidale 330 kV line	1. A set of coal-fired or gas-fired generators, with a combined output exceeding 300 MW (or wind farm developments that provide the equivalent output at time of high NSW load), is committed for connection to the network in NSW in the Armidale to north coast area or 2. The NSW import capability from Queensland is increased by 300 MW above the present capability or 3. The NSW export capability to Queensland is increased by 200 MW above the present capability. and The generation development or increased export capability causes a network limitation to arise on the system between Tamworth and Armidale	130
Bannaby − Yass reinforcement	1. A set of coal-fired or gas-fired generators, with combined output exceeding 200 MW, is committed for connection to the network in the following southern areas of the NSW system south of the Bannaby/Marulan area: - Yass - Canberra - Wagga - Jindera - Buronga/Broken Hill area - Snowy area or 2. The Victorian export capability to Snowy and NSW is increased by 200 MW above the present capability. and The generation development or increased export capability causes a network limitation to arise on the system between Yass and Bannaby.	$45
Cooma area	The emergence of one or more generators totalling 225 MW (or more) to be connected to the transmission network which services the Cooma Area	$40
New 500/330 kV substation at Richmond Vale	1. The environmental consent authority determines that a 500 kV transmission line between the Hunter Valley and Eraring must utilize the route of an existing 330 kV line that supplies the Newcastle area in order to be approved, and 2. The project including the 500/ 330 kV substation satisfies the Regulatory Test	$80

Source: PB, pp. 147−149.

AER considerations

The AER is required to determine if TransGrid's proposed contingent projects satisfy the requirements of clause 6A.8.1 of the NER.

The AER notes PB identified a number of concerns with TransGrid's proposed contingent projects, including the use of the completion of the regulatory test as a trigger—a trigger PB considered was often not sufficiently or specifically defined outside the bounds of the scenario analysis. The EUAA similarly suggested TransGrid's proposed contingent projects were not adequately substantiated and were excessive.

The AER also agrees with PB in that the successful completion of the regulatory test by itself is not an appropriate trigger, as this will not either generate increased costs at a location or make the undertaking of the relevant contingent project necessary to achieve the capital expenditure objectives. That is, while a regulatory test may be reasonably specific and capable of objective verification (clause 6A.8.1(c) (1)) it does not, of itself demonstrate that:

- there is a condition or event, which, if it occurs, makes the undertaking of the proposed contingent project reasonably necessary (clause 6A.8.1(c) (2)); or
- it will generate increased costs or categories of costs that relate to a specific location rather than a condition or event that affects the transmission network as a whole 6A.8.1(c) (3).

The AER notes that TransGrid was informed of the need to adequately specify triggers during PB's review and that it offered several revisions to the proposed triggers for PB's consideration. In discussions with the AER, TransGrid suggested that the degree of specification required under the NER for some projects would involve an unreasonable level of detail, for example, in the case of the CBD security of supply project. In this case, the AER considers that TransGrid may have proposed a scope of work in excess of a specific trigger in order to provide benefits for the broader transmission network.[186] In another case, 'reactive support at six sites', the difficulties in defining an appropriate trigger may relate to the grouping of what appear to be several smaller projects which individually may be considered efficient by the AER but which do not meet the materiality requirements for a contingent project.[187]

For the Williamsdale 330 kV substation, there also appears to be some ambiguity regarding the exact trigger and project scope. The AER notes that the proposed trigger for the Williamsdale 330 kV substation was revised by TransGrid during consultation from change in system security requirements (which was accepted by PB as an appropriate trigger) to gaining planning approval by the ACT Government (which was not). To the extent that the underlying need for the investment already exists, TransGrid may wish to consider the appropriateness of this project as part of its capex allowance.

[186] PB, p. A172.
[187] PB, p. A172.

On the basis of the observations outlined above, information provided by TransGrid and PB's analysis, the AER agrees with PB's conclusion that nine of TransGrid's proposed contingent projects should be considered as satisfying the requirements of clause 6A.8.1 of the NER. A contingent allowance of $1.2 billion is therefore supported for inclusion in TransGrid's determination. The nine contingent projects to be included are shown in table 3.22.

3.6.12 Deliverability of the capex program

An assessment of deliverability is made because under the capex incentive framework a TNSP is able to retain, within the regulatory control period, the excess return on and of capital associated with a lower than approved capex allowance. The AER considers this is an important issue relevant in determining whether it is satisfied TransGrid's proposed forecast capex reasonably reflects the capex criteria.

TransGrid proposal

TransGrid's proposal recognises that its proposed capex is a significant increase from the current regulatory control period but notes there have been significant changes that have improved its capacity to deliver. It also notes that some of the program associated with the next regulatory control period is already underway and that three significant projects form a significant part of the program.

TransGrid is also aware that it will be competing with other Australian energy businesses, as well as in the broader international market, for resources and expertise to deliver its proposed capital and operating expenditure program. Some of the key changes TransGrid has put in place to ensure the deliverability of its capex program include: [188]

- changes to its organisational structures, including the formation of the Capital Program Delivery business unit, with increased resources to support those structures
- growing internal resources and establishment of long-term contracts with major engineering companies
- competitive tendering
- extended period agreements (from three to five years) with major manufacturers of transmission infrastructure to ensure timely delivery of major capital works
- diversifying its sourcing of major equipment from traditional suppliers to select Chinese and Thai manufacturers.

Submissions

The EMRF highlighted that robust risk analysis, including an assessment for delaying projects, should have been undertaken and that TransGrid's ability to implement its capex program could be hindered by supply constraints.[189]

[188] TransGrid, *Revenue proposal*, pp. 77−79.
[189] EMRF, pp.14−15.

The EUAA highlighted that when the contingent projects are assessed with TransGrid's overall capex program there are deliverability concerns and this could have implications for system security and reliability.[190]

Consultant review

PB concluded TransGrid should be able to deliver its capex program because:[191]

- it has already implemented strategies that have allowed it to have a high degree of confidence in the delivery of its 2008–09 capital program, and the program of proposed expenditure is similar in size to that. The continuation and extension of those strategies should enable TransGrid to deliver its capex program in the next regulatory control period
- it will able it to leverage off its experience in using the design and construct approach for large substation projects and successfully extend this approach to the three large (transmission lines and cables) augmentation projects planned for the next regulatory control period
- while some effort is involved in planning and negotiating payments associated with the purchase of land or payments to landowners for easements, the size of the planned expenditure will not be a constraint on the delivery.

More broadly, PB considered TransGrid has implemented a number of successful strategies to increase its capacity to deliver its capital program, including:[192]

- the recruitment of additional staff
- the establishment of new business units
- the use of external design resources
- long term procurement contracts.

PB was, however, concerned that TransGrid has not fully demonstrated that a detailed skills analysis has been performed and matched against the proposed capital program. PB considered that if this was undertaken there was scope for this to improve confidence that the capital program will not be constrained by skills in any key area.[193]

PB also observed, notwithstanding the highly unlikely situation, that should any of the contingent project triggers be realised and require significant additional capital investment, TransGrid may not be in a position to deliver this.[194]

AER considerations

The AER notes TransGrid has implemented a number of reforms that will assist it in the delivery of its capital program. In particular, the AER notes that TransGrid has:

---

190 EUAA, pp. 4, 21–22.
191 PB, pp. 154−155.
192 PB, pp. 154−156.
193 PB, p. 157.
194 PB, p. 157.

- extended and developed its relationship with major engineering and manufacturing businesses
- recruited additional staff
- established long term procurement contracts
- the use of external design resources.

The AER is of the view TransGrid is likely to be well positioned to deliver its capex program, even if the international credit crisis continues to worsen for a number of reasons. In particular, the AER notes the financial reforms TransGrid has implemented in this area over recent years. For example, in 2006–07, through work on monitoring cash flows to minimise changes in debt levels, TransGrid achieved a significant reduction in its gross interest costs despite maintaining debt levels at an almost constant figure during a period of rising interest rates.[195]

The AER notes the EMRF's concerns that TransGrid's ability to implement its capex program could be hindered by supply constraints. However, the AER agrees with PB's finding that reasonable steps have been undertaken to ensure TransGrid will be in position to overcome any supply constraints. In particular TransGrid has enhanced its ability to source equipment from new sources such as China and Thailand. The AER also notes that if the global economic conditions worsen, the capacity for TransGrid (and other energy businesses) to access the resources required for the delivery of its capex program, including skilled staff, may be improved. In addition, the AER notes that TransGrid's formal planning processes demonstrate a prudent approach to forward planning and that it is structured primarily to meet its associated forward capex requirements and its regulatory reporting requirements (section 3.6.2). More broadly, PB found TransGrid governance arrangements are consistent with good industry practice. As discussed earlier, the AER agrees with PB in this regard.

The AER also note the EUAA's concerns that when the proposed contingent projects are assessed with TransGrid's overall capex program, there are deliverability concerns. However, the AER notes that PB identified this as a potential challenge and noted it was highly unlikely to occur.[196]

On balance, and based on the information provided by TransGrid, PB's analysis and the information discussed above, the AER considers the initiatives implemented by TransGrid are likely to provide it with the potential to deliver its capex program in the next regulatory control period. The AER notes, however, that while TransGrid has improved its supply relationships and governance arrangements, and has engaged more staff in order to deliver the level of capex expected over the next regulatory control period, the AER will carefully monitor and report on the expenditures of TransGrid, and indeed all TNSPs and the NSW DNSPs, on an annual basis. In particular, it will publish the actual capex spent by each NSP, including any under or

[195] TransGrid, *TransGrid Annual Report 2007*, p. 15.
[196] PB, p. 159.

over spends if they occur. The AER's conclusion is also subject to the proviso that TransGrid can adequately finance its proposed capex program.[197]

3.7 AER conclusion

The AER is not satisfied that TransGrid's proposed forecast capex allowance of $2.6 billion ($2007–08), for the reasons outlined in this chapter, reasonably reflects the capex criteria under clause 6A.6.7(c), namely:

- the efficient costs of achieving the capex objectives
- the costs that a prudent operator in the circumstances of the relevant TNSP would require to achieve the capex objectives, and
- a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.

In reaching this conclusion, the AER has had regard to the capex factors set out in clause 6A.6.7(e) of the NER.

As the AER is not satisfied that TransGrid's forecast capex reasonably reflects the capex criteria, under clause 6A.6.7(d), it must not accept the forecast capex allowance in TransGrid's revenue proposal. Therefore, the AER is required under clause 6A.14.1(2)(ii) to provide an estimate of the total capex that TransGrid will require over the next regulatory control period which the AER is satisfied reasonably reflects the capex criteria, taking into account the capex factors.

Based on its analysis of TransGrid's proposed capex allowance and the advice of PB the AER has reduced TransGrid's capex allowance by $173 million. This represents a reduction of around 6.8 per cent to TransGrid's proposed capex of $2550 million. The AER's amended capex allowance for the next regulatory control period is $2376 million and is set out in table 3.23 along with the adjustments made to TransGrid's capex proposal.[198] In addition, the AER has approved an indicative contingent projects allowance of $1.2 billion.

The amended allowance of $2376 million represents the AER's estimate that it is satisfied are the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria taking into account the capex factors, during the next regulatory control period.[199]

---

197 The AER notes that the NSW Government's *Mini Budget 2008–09* provides for a reduction of $857 million over three years in the borrowing capacity of TransGrid and the NSW DNSPs. The AER has assessed this financing constraint against the proposed capex programs from 2009–10 to 2011–12, and is satisfied that this need not adversely impact on the deliverability of the program. The reduction in the borrowing program represents a relatively small proportion of the capex program and its impact may be offset by increased internal efficiencies in each of the businesses and or by a change in the timing of dividend payments to the to the shareholder. See: <http://www.treasury.nsw.gov.au/__data/assets/pdf_file/0016/12706/08-09_Mini-Budget.pdf>.

198 While a number of the adjustments made by the AER are a result of the detailed project reviews undertaken by PB, the AER's conclusions on these projects should not be considered as binding—TransGrid has the ultimate discretion on how it allocates its capex allowance.

199 The forecast capex allowance is $2443 million in 2008–09 dollar terms.

Table 3.23: AER's conclusion on TransGrid's capex allowance ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's updated proposal	531.9	465.9	579.2	552.3	420.6	2549.8
Adjustments resulting from detailed project review	3.2	–14.0	–15.4	–19.7	–31.4	–77.2
Replacement programs	–0.8	–2.0	–1.0	–0.9	–0.9	–5.6
Adjustment to cost accumulation process[a]	–6.4	–9.1	–12.6	–16.9	–15.0	–59.9
Application of annual escalators	0.6	–0.1	–6.3	–2.4	3.5	–4.7
Adjustment to cost estimation risk factor	–2.3	–2.0	–2.6	–2.5	–1.8	–11.4
Agreed adjustments (not included in TG's updated proposal)	–0.2	–0.2	–0.4	–0.2	–0.3	–1.2
Cost estimating factors adjustment	–2.8	–2.4	–3.0	–2.9	–2.2	–13.3
AER's total adjustments	–8.7	–29.4	–41.1	–45.6	–48.1	–173.3
AER's capex allowance	523.5	436.1	538.1	506.5	372.4	2376.5

Note: Totals may not add up due to rounding.
(a) This includes adjustments to labour and materials cost escalators.

4 Cost of capital

4.1 Introduction

This chapter sets out the AER's estimate of an efficient (market-based) benchmark weighted average cost of capital (WACC) or the rate of return for TransGrid over the next regulatory control period. The key issues considered include the WACC parameters specified in the NER and the determination of the risk-free rate, debt risk premium and inflation forecast.

The AER's consideration of debt and equity raising costs, and corporate tax allowances is not set out in this chapter because they are not compensated for through the WACC. Accordingly, the analysis of debt and equity raising costs is found in chapter 5 and the analysis of corporate tax is found in chapter 9 of this draft decision.

4.2 Regulatory requirements

Clause 6A.6.2 of the NER requires that the return on capital be calculated by applying the rate of return to the value of the regulatory asset base (RAB) as determined in chapter 2 of this draft decision.

The AER must determine the rate of return in accordance with clause 6A.6.2 of the NER. Clause 6A.6.2(b) provides that the rate of return for a TNSP is a nominal post-tax WACC calculated in accordance with the following formula:

$$\text{WACC} = k_e \frac{E}{V} + k_d \frac{D}{V}$$

where:

k_e = the return on equity

k_d = the return on debt

E/V = the market value of equity as a proportion of the market value of equity and debt, which is 1 – D/V

D/V = the market value of debt as a proportion of the market value of equity and debt, which is deemed to be 0.6.

It also states that the return on equity (k_e) is determined by using the capital asset pricing model (CAPM):

$$k_e = r_f + \beta_e \times \text{MRP}$$

where:

r_f = the nominal risk-free rate of return for the regulatory control period determined in accordance with clause 6A.6.2(c)

MRP = the market risk premium, which is deemed to be 6 per cent

β_e = the equity beta which is deemed to be 1.

It also states that the return on debt (k_d) is calculated as:

$$k_d = r_f + DRP$$

where:

DRP = the debt risk premium for the regulatory control period is determined in accordance with clause 6A.6.2(e).

4.3 TransGrid proposal

In estimating the WACC for its revenue proposal, TransGrid has used the values for the WACC parameters set out in the NER. For the purposes of its revenue proposal TransGrid has calculated a nominal vanilla WACC of 9.15 per cent. The parameters underlying TransGrid's calculation of the WACC are presented in table 4.1.

Table 4.1: TransGrid's proposed WACC parameters

Parameter	TransGrid's proposal
Risk-free rate (nominal)	5.70%
Expected inflation rate	2.52%
Debt risk premium	1.75%
Market risk premium	6.00%
Corporate tax rate	30%
Value of imputation credits	50%
Proportion of equity funding	40%
Proportion of debt funding	60%
Equity beta	1.00
Nominal vanilla WACC	9.15%

Source: TransGrid, *Revenue proposal*, p. 115.

4.4 Submissions

The Energy Users Association of Australia (EUAA) noted that the AER is currently undertaking a review of the parameters used in calculating the WACC. It argued that the parameters emerging from this review should be applied in determining TransGrid's WACC and that failing to do so would result in the use of out-of-date parameters.[200]

[200] EUAA, p. 30.

The EUAA also stated that the averaging period used to calculate the risk-free rate and debt risk premium should appropriately reflect the current credit crisis and global slow-down.[201]

4.5 Issues and AER considerations

4.5.1 The WACC parameters specified in the NER

Businesses are typically funded by a combination of equity and debt. Therefore, a weighted average cost of equity and debt must be established to derive the rate of return. This is usually referred to as the WACC. The derivation of the WACC requires several parameters. Many of these parameters have values specified in the NER. Where the NER does not specify a value, it specifies a method for determining the value.

The NER specifies values for the equity beta and the market risk premium to be used to calculate the return on equity using the CAPM. The NER also specifies the value of debt as a proportion of the value of equity and debt (or gearing) to be used when calculating the WACC.

TransGrid proposal

TransGrid has estimated the return on equity using the CAPM and adopted the parameter values specified in the NER for the equity beta, market risk premium (MRP) and gearing.[202]

Submissions

The EUAA argued that the parameters emerging from the AER's WACC review should be applied in determining TransGrid's WACC and that failing to do so would result in the use of out-of-date parameters.[203]

AER considerations

Based on the NER requirements, the parameters and values as outlined in section 4.2 of this draft decision have been applied by the AER for the purposes of determining the WACC for TransGrid.

The AER will not apply the WACC parameters or methods determined by the WACC review it is currently undertaking. The AER notes that clause 6A.6.2(h) of the NER only allows parameters or methods determined by the WACC review to be adopted for revenue proposals that have been submitted to the AER after the completion of the review.

4.5.2 The risk-free rate

The risk-free rate measures the return an investor would expect from an asset with zero volatility and zero default risk. The yield on long-term Commonwealth Government Securities (CGS) is often used as a proxy for the risk-free rate because

[201] EUAA, p. 31.
[202] TransGrid, *Revenue proposal*, p. 113.
[203] EUAA, p. 30.

the risk of government default on interest and debt repayments is considered to be low.

In the CAPM framework, all information used for deriving the rate of return should be as current as possible. While it may be theoretically correct to use the on-the-day rate as it represents the latest available information, this can expose the TNSP to day-to-day volatility. For this reason, an averaging method is used to minimise volatility in observed bond yields.

Regulatory requirements

Clause 6A.6.2(c) states that the nominal risk-free rate is to be determined by the AER:

> … on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years using:
>
> (1) the indicative mid rates published by the Reserve Bank of Australia; and
>
> (2) a period of time which is either:
>
> (i) a period ('the agreed period') proposed by the relevant TNSP, and agreed by the AER (such agreement is not to be unreasonably withheld); or
>
> (ii) a period specified by the AER, and notified to the provider prior to the commencement of that period, if the period proposed by the provider is not agreed by the AER under subparagraph (i),
>
> and, for the purposes of subparagraph (i):
>
> (iii) the start date and end date for the agreed period may be kept confidential, but only until the expiration of the agreed period; and
>
> (iv) the AER must notify the TNSP whether or not it agrees with the proposed period within 30 business days of the date of submission of the revenue proposal under clause 6A.10.1(a).

Clause 6A.6.2(d) states that if there are no CGS with a maturity of 10 years on any day in the averaging period, the AER must determine the nominal risk-free rate by:

> … interpolating on a straight line basis from the two Commonwealth Government bonds closest to the 10 year term and which also straddle the 10 year expiry date.

TransGrid proposal

TransGrid nominated an averaging period of 20 days to calculate the nominal risk-free rate. TransGrid proposed an indicative risk-free rate of 5.70 per cent based on annualised CGS yields with a maturity of 10 years for the purposes of its proposal, recognising that the AER will determine the applicable risk-free rate at a time closer to its final determination.[204]

[204] TransGrid, *Revenue proposal,* p. 114.

Submissions

The EUAA noted concerns regarding recent volatility within financial markets and recommended that the AER carefully consider the effects of the current credit crisis and global slow-down when approving the averaging period used to calculate the risk free rate and the debt risk premium.[205]

AER considerations

Clause 6A.6.2(c) of the NER requires the AER to determine the nominal risk-free rate using annualised CGS yields with a maturity of 10 years.

In accordance with clause 6A.6.2(c), TransGrid proposed an averaging period to estimate the risk-free rate. The AER does not agree with the period proposed on the basis that the proposed dates were too far removed from the date of the final determination and the commencement of the next regulatory control period. A period that is too far removed from the final determination date may not provide the most relevant information. This is consistent with past practice by the AER and other state regulators, and supported by CAPM theory.[206]

The AER specified a period that is closer to the final determination date and TransGrid indicated it was prepared to accept a period within the window proposed by the AER (based on an averaging period of 20 business days). The AER has accepted TransGrid's revised proposal as it considers the 20 day averaging period and revised dates addresses its earlier concerns. The AER agreed to keep the start and end dates of the averaging period confidential until the expiration of the period as requested by TransGrid.

For this draft decision, the 20 day moving average for CGS yields[207] with a 10-year maturity for the period ending 17 October 2008 results in a proxy nominal risk-free rate of 5.46 per cent (effective annual compounding rate). The AER will update the risk-free rate, based on the AER's specified averaging period, at a time closer to its final determination.

4.5.3 The debt risk premium

The debt risk premium (or debt margin) is added to the nominal risk-free rate to calculate the return on debt, which is an input for calculating the WACC. The debt risk premium is the margin above the risk-free rate that investors in a benchmark efficient TNSP are likely to demand as a result of issuing debt to fund the business operations. It is intended to equate to a commercial cost of debt.

The debt risk premium varies depending on the entity's operational and financial risk as well as the term of the debt. This can be characterised as a credit rating. Applying the return on debt (as a percentage) to the RAB, adjusted for the assumed gearing, will generate the interest expense for regulatory purposes (also referred to as the cost of debt).

---

205 EUAA, p. 30.

206 Martin Lally, The cost of capital for regulated entities, report prepared for the Queensland Competition Authority, 26 February 2004, p. 63.
Kevin Davis, Report on risk free interest rate and equity and debt beta determination in the WACC, report prepared for the ACCC, 28 August 2003, p. 16.

207 RBA, CGS yields at: http://www.rba.gov.au/Statistics/indicative.html.

Regulatory requirements

Clause 6A.6.2(b) states that the return on debt is calculated as:

$$k_d = r_f + DRP$$

Where:

r_f = the nominal risk-free rate

DRP = the debt risk premium for the regulatory control period determined in accordance with clause 6A.6.2(e).

Clause 6A.6.2(e) of the NER states that the debt risk premium is:

> … is the premium determined for that regulatory control period by the AER as the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a BBB+ credit rating from Standard and Poors and a maturity equal to that used to derive the nominal risk free rate.

TransGrid proposal

TransGrid noted the current volatility in the market and argued that current market rates are 'unhelpful and possibly misleading'. TransGrid stated that it is more appropriate to include a value for the debt risk premium in line with historical averages.[208] TransGrid has proposed a debt risk premium of 1.75 per cent for the purposes of its proposal, recognising that the AER will determine the applicable debt risk premium at a time closer to its final determination.[209] TransGrid envisaged that the AER's final determination will use the averaging period nominated by TransGrid and agreed by the AER on a confidential basis.

TransGrid did not discuss the specific method to be used for calculating the debt risk premium or the source of market data.

AER considerations

In previous revenue determinations the AER conducted a review which compared the estimated average daily fair yields for corporate bonds with BBB+ credit rating and maturity of up to 10 years from the Bloomberg and CBASpectrum databases over a period.[210] Differences between the average yields for actual bonds with the estimated average fair yields from the two databases were observed. The review indicated that Bloomberg provides estimates of BBB+ rated, long-term fair yields which are more consistent with the observed yields of similarly rated actual bonds. The AER has therefore decided to use the fair yields estimated by Bloomberg, rather than CBASpectrum, to determine the benchmark debt risk premium margin for TransGrid.

---

208 TransGrid, *Revenue proposal*, p. 114.

209 TransGrid, *Revenue proposal*, p. 114.

210 AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, Draft Decision, 8 December 2006, pp. 103-104; and
AER, *Directlink Joint Venturers' application for conversion and revenue cap*, Decision, 3 March 2006, pp. 211, 221.

The AER has previously used BBB 10-year corporate bond fair yields sourced from Bloomberg for the purposes of establishing a 10-year benchmark debt risk premium with a BBB+ credit rating.[211] In late October 2007, Bloomberg ceased publication of its BBB fair yields for bonds with 9 or 10-year maturities. The AER understands that the decision to cease publication was based on a lack of data for these long-dated corporate bonds (within the BBB credit rating category) from which Bloomberg could produce a fair yield. The longest maturity BBB bond fair yield now published by Bloomberg is 8 years.

Due to the unavailability of the Bloomberg fair yields for BBB rated 10-year corporate bonds, it is necessary to adopt an alternative proxy for deriving a 10-year BBB+ benchmark debt risk premium, as required by the NER.[212] The AER recently considered this issue and the details are set out in its SP AusNet final transmission determination.[213] Specifically, the methodology applied by the AER is to take the Bloomberg fair yield for BBB rated 8-year corporate bonds and add the Bloomberg fair yield spread between A rated 8 and 10-year corporate bonds, in order to derive a proxy 10-year BBB+ corporate bond yield. The AER considers that this methodology remains appropriate for the purposes of determining the benchmark debt risk premium for TransGrid.

Consistent with previous regulatory practice, the AER considers that the debt risk premium should be determined with reference to the same averaging period that was adopted for determining the risk-free rate. For this draft decision, the 20-day moving average benchmark debt risk premium for the period ending 17 October 2008, based on BBB+ rated corporate bonds with a maturity of 10 years, is 3.27 per cent (effective annual compounding rate).[214] Adding this debt risk premium to the nominal risk-free rate of 5.46 per cent provides a nominal return on debt of 8.73 per cent. The AER is satisfied that the debt risk premium is consistent, under clause 6A.6.2(e), with the required margin between the 10-year CGS yield and observed Australian benchmark corporate bond yields corresponding to BBB+ credit rating and maturity of 10 years.

The debt risk premium will be updated by the AER based on this methodology at a time closer to its final determination. As outlined above in relation to the risk-free rate, the AER did not agree with the averaging period originally nominated by TransGrid and has substituted an alternative averaging period to use in its calculations for the final determination.

4.5.4 Expected inflation

The expected inflation rate is not an explicit parameter within the WACC calculation; however, it is used in the post-tax revenue model (PTRM) to forecast nominal allowed revenues. It is an implicit component of the nominal risk-free rate, with implications for the return on both equity and debt. The PTRM framework essentially

---

211 Bloomberg's BBB fair yields are assumed to approximate BBB+ fair yields due to the estimation technique employed and the market being disproportionately weighted with longer term BBB+ rated bonds.

212 The proxy corporate bond yield less the risk-free rate produces the debt risk premium.

213 AER, *SP AusNet transmission determination, 2008–09 to 2013–14,* Final decision, January 2008, pp. 94–98.

214 Bloomberg's BBB fair yields are assumed to approximate BBB+ fair yields due to the estimation technique employed and the market being disproportionately weighted with longer term BBB+ rated bonds.

provides a real rate of return to the business, which means that the expected inflation rate included in the nominal WACC must be appropriately measured.

Regulatory requirements

Clause 6A.5.3(b)(1) states that the PTRM must specify:

> … a methodology that the AER determines is likely to result in the best estimates of expected inflation.

Historically, the AER has used an objective market-based approach to forecast the expected inflation rate—calculated as the difference in the CGS (nominal) and the indexed CGS yields. However, since late 2006 a downward bias in the indexed CGS has become evident due to the limited supply of these securities. Consequently, using this method potentially results in an overestimate of expected inflation. This limitation was recognised in the AER's PTRM guideline for TNSPs.[215]

In its recent final determinations for ElectraNet and SP AusNet, the AER applied the RBA's short-term inflation forecasts for the first two years of the next regulatory control period and adopted the mid-point of its target inflation band (that is, 2.5 per cent) for the remaining eight years. An implied 10-year forecast is derived by averaging these individual forecasts. This aligns the inflation forecast to the term of the risk-free rate.

TransGrid proposal

TransGrid proposed an annual inflation forecast of 2.52 per cent per annum for the next regulatory control period. This has been determined based on a two part method to setting the long term forecast inflation over a 10-year period, which is similar to that applied by the AER in recent transmission determinations:[216]

- determining a short term forecast of inflation for the first two year period based on a reliable forecast
- adoption of the mid-point of the Reserve Bank of Australia (RBA) target inflation band of 2–3 per cent beyond that period due to the inherent difficulties in forecasting inflation over the longer term.

TransGrid considered that the RBA inflation forecasts adopted by the AER in previous determinations are not the most appropriate short-term forecasts to be used as they are 'not true inflation forecasts' but rather a 'policy signalling mechanism'.[217] Along with other NSW network businesses, TransGrid engaged the Competition Economists Group (CEG) to provide advice on escalation factors, which included estimates of inflation for 2009 and 2010 of 2.8 per cent and 2.4 per cent respectively.[218] By applying the AER's method and utilising the CEG forecasts,

---

215 AER, *Electricity transmission network service providers—Post–tax revenue model*, Final decision, September 2007, pp. 9–10.
216 TransGrid, *Revenue proposal*, pp. 114–115.
217 TransGrid, *Revenue proposal*, p. 115.
218 CEG, *NSW electricity businesses*, p. 6.

TransGrid proposed an average forecast inflation rate for the 10-year period of 2.52 per cent.[219]

AER considerations

The AER has determined in previous transmission determinations that a method that is likely to result in the best estimate of inflation over a 10-year period is to apply the RBA's short-term inflation forecasts—currently extending out to two years—and adopt the mid-point of its target inflation band beyond that period (i.e. 2.5 per cent) for the remaining eight years. An implied 10-year forecast is derived by averaging these individual forecasts.

The inflation forecasting methodology proposed by TransGrid in its revenue proposals is broadly similar to that applied by the AER for its previous transmission determinations.[220] The difference between the two approaches, however, is the range of sources used to establish the 10-year average inflation estimate. TransGrid's proposed methodology draws on forecasts from a number of independent economic forecasters,[221] while the AER's approach in previous transmission determinations relies on the RBA's inflation forecasts and the mid-point of its target band.

The AER notes the RBA's responsibility for monetary policy in Australia means it is an independent authority on inflation expectations. The AER considers that the RBA's inflation forecasts are objective and represent the best estimates of forecast inflation for the purpose of this draft decision. The RBA's statement on monetary policy examines a wide variety of objective data influencing inflation in both the domestic and international financial markets to develop its inflation forecast. The forecast is produced on a regular basis and is publicly available, including supporting analysis and reasoning. The AER's approach uses the RBA statement on monetary policy, which provides consistency and transparency in the AER process for deriving an inflation forecast.

In the absence of an objective market-based approach, the AER considers that its methodology will result in the best estimates of expected inflation for the purposes of determining an inflation forecast in its transmission determinations. The AER has updated the inflation forecast for the first two years of the regulatory control period using the latest published RBA inflation expectations as shown in table 4.2. The AER considers that, based on a simple average, an inflation forecast of 2.55 per cent per annum produces the best estimate for a 10-year period to be applied in the PTRM for this draft decision.

The AER recognises that inflation forecasts will change in line with market sensitive data. Regulatory practice in Australia has been to update these parameter values at the time of making a final determination to take account of most recent information. Accordingly, the AER will update the inflation forecast to be used in the PTRM based on this methodology at a time closer to its final determination.

---

219 TransGrid, *Revenue proposal*, pp. 114–115.

220 AER, *Final decision – ElectraNet transmission determination*, pp. 69–70.
AER, *Final decision – SP AusNet transmission determination*, pp. 99–106.

221 CEG, *NSW electricity businesses*, p. 6.

Table 4.2: AER's conclusion on inflation forecast (per cent)

	June 2010	June 2011	June 2012	June 2013	June 2014	June 2015	June 2016	June 2017	June 2018	June 2019	Average
Forecast inflation	3.00	2.50[a]	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.55

Source: RBA, *Statement on monetary policy*, 11 August 2008, p. 62.
(a) The RBA has not yet released a forecast for the year ending June 2011. This forecast will be available and adopted by the AER (including any updated forecasts) at the time of the final decision. The mid-point of its target inflation band has been assumed for the purposes of this draft decision.

4.6 AER conclusion

The NER prescribes a number of the WACC parameter values to be adopted by the AER for the purposes of setting a rate of return for TNSPs. For the parameters where the values have not been prescribed—nominal risk-free rate and the debt risk premium—the NER sets out the methodology to be used by the AER for determining the values.

For this draft decision, the AER has determined a nominal vanilla WACC of 9.82 per cent for TransGrid. Due to the current high cost of debt, the WACC is greater than that proposed by TransGrid, which was based on the historical average of the cost of debt.

Table 4.3 outlines the WACC parameter values for the draft determination. The AER will update the nominal risk-free rate and debt risk premium, based on the agreed averaging period, and the expected inflation rate at a time closer to its final determination.

Table 4.3: AER's conclusion on TransGrid's WACC parameters

Parameter	TransGrid's proposal	AER's conclusion
Risk-free rate (nominal)	5.70%	5.46%
Risk-free rate (real)[a]	3.10%	2.84%
Expected inflation rate	2.52%	2.55%[b]
Debt risk premium	1.75%	3.27%
Market risk premium	6.00%	6.00%
Gearing	60%	60%
Equity beta	1.00	1.00
Nominal pre-tax return on debt	7.45%	8.73%
Nominal post-tax return on equity	11.70%	11.46%
Nominal vanilla WACC	9.15%	9.82%

(a) The real risk-free rate was derived using the Fisher equation.
(b) Established using RBA forecasts and targets.

5 Forecast operating expenditure

5.1 Introduction

This chapter sets out the AER's assessment of TransGrid's opex proposal for the next regulatory control period. The AER has reviewed TransGrid's opex proposal against the requirements of the NER.

The opex forecasts in TransGrid's proposal refer to its requirements for the provision of prescribed transmission services in the next regulatory control period.

5.2 Regulatory requirements

5.2.1 Opex objectives

Clause 6A.6.6(a) of the NER provides that a TNSP must include in its revenue proposal the total forecast opex for the regulatory control period in order to achieve the opex objectives, which are to:

> (1) meet the expected demand for prescribed transmission services over that period;
>
> (2) comply with all applicable regulatory obligations or requirements associated with the provision of prescribed transmission services;
>
> (3) maintain the quality, reliability and security of supply of prescribed transmission services; and
>
> (4) maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

5.2.2 Opex criteria and factors

Clause 6A.6.6(c) of the NER provides that the AER must accept the forecast opex included in a revenue proposal if the AER is satisfied that the total forecast opex for the regulatory control period reasonably reflects the opex criteria, which are:

> (1) the efficient costs of achieving the operating expenditure objectives;
>
> (2) the costs that a prudent operator in the circumstances of the relevant TNSP would require to achieve the operating expenditure objectives; and
>
> (3) a realistic expectation of the demand forecast and cost inputs required to achieve the operating expenditure objectives.

In making this assessment, the AER must have regard to the opex factors set out in clause 6A.6.6(e) of the NER:

> (1) the information included in or accompanying the Revenue Proposal;
>
> (2) submissions received in the course of consulting on the Revenue Proposal;

(3) such analysis as is undertaken by or for the AER and is published prior to or as part of the draft decision of the AER on the Revenue Proposal under rule 6A.12 or the final decision of the AER on the Revenue Proposal under rule 6A.13 (as the case may be);

(4) benchmark operating expenditure that would be incurred by an efficient TNSP over the regulatory control period;

(5) the actual and expected operating expenditure of the TNSP during any preceding regulatory control periods;

(6) the relative prices of operating and capital inputs;

(7) the substitution possibilities between operating and capital expenditure;

(8) whether the total labour costs included in the capital and operating expenditure forecasts for the regulatory control period are consistent with the incentives provided by the applicable service target performance incentive scheme in respect of the regulatory control period;

(9) the extent to which the forecast of required operating expenditure of the TNSP is referable to arrangements with a person other than the provider that, in the opinion of the AER, do not reflect arm's length terms; and

(10) whether the forecast of required operating expenditure includes amounts relating to a project that should more appropriately be included as a contingent project under clause 6A.8.1(b).

Clause 6A.6.6(d) of the NER states that if the AER is not satisfied that a TNSP's forecast opex reasonably reflects the opex criteria then the AER must not accept the forecast opex in a revenue proposal. If the AER does not accept the total forecast opex proposed by a TNSP, clause 6A.14.1(3)(ii) of the NER requires the AER to include in its draft decision:

> …an estimate of the total of the Transmission Network Service Provider's required operating expenditure for the regulatory control period that the AER is satisfied reasonably reflects the operating expenditure criteria, taking into account the operating expenditure factors.

5.3 TransGrid proposal

TransGrid's forecast opex for the next regulatory control period is $849 million ($2007–08). This is $166 million higher than its expected actual opex in the current regulatory control period. TransGrid identified the following significant cost drivers:[222]

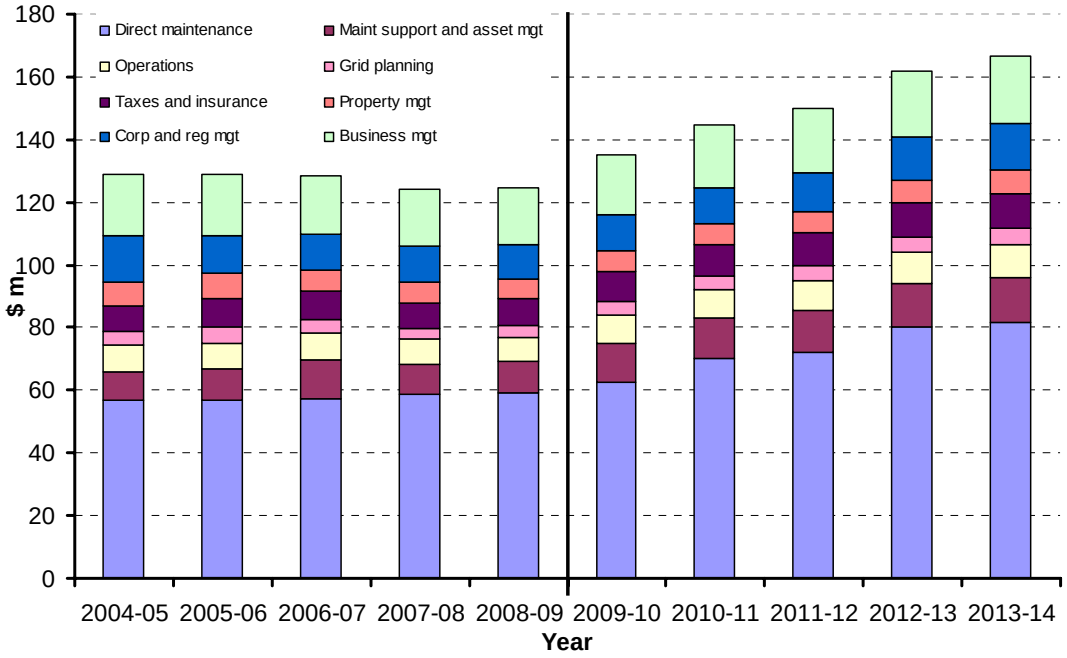
- growth in the asset base over the next regulatory control period
- forecast increases in the cost of labour above the expected growth in CPI
- increases in the costs of operating materials and expenses

[222] TransGrid opex model version 4.0.

- forecast demand growth requiring greater network support expenditure.

Figure 5.1 shows TransGrid's expected actual controllable opex for the current regulatory control period and TransGrid's forecast controllable opex for the next regulatory control period.

Figure 5.1: TransGrid's controllable opex from 2004–05 to 2013–14 ($m, 2007−08)



Source: TransGrid, *Revenue proposal*, pp. 46, 90.

Table 5.1 sets out TransGrid's forecast opex by cost category and year for the next regulatory control period.

During the course of the review of TransGrid's revenue proposal, TransGrid published its 2008 Annual Planning Report (APR) which includes a revised load forecast.[223] The 2008 APR has resulted in a reduction of $77 million ($2007–08) to TransGrid's forecast capex for the next regulatory control period. The 2008 APR also has an impact on TransGrid's forecast opex and is discussed further at section 5.6.5.

[223] TransGrid's revenue proposal was based on capex developed using the 2007 APR load forecasts.

Table 5.1: TransGrid's forecast opex by category and year ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Maintenance	62.5	70.1	72.2	80.1	81.7	366.5
Maintenance support & asset management	12.6	12.8	13.3	13.9	14.4	67.0
Operations	9.1	9.3	9.6	10.1	10.5	48.5
Grid planning	4.2	4.3	4.5	4.7	4.9	22.4
Taxes & insurance	9.4	9.9	10.5	11.1	11.4	52.2
Property management	6.6	6.7	6.9	7.1	7.3	34.7
Corporate & regulatory management	11.5	11.7	12.5	13.9	14.8	64.4
Business management	19.4	19.7	20.3	20.9	21.6	101.9
Total controllable opex	135.2	144.4	149.7	161.8	166.5	757.6
Debt raising	3.7	4.0	4.3	4.8	5.1	22.0
Equity raising	0.9	1.7	3.1	4.0	4.2	13.9
Self insurance	1.9	1.9	1.9	1.9	1.9	9.6
Network support	21.5	6.0	6.0	6.0	6.0	45.5
Total other opex	28.0	13.6	15.4	16.8	17.2	90.9
Total opex proposal	163.3	158.0	165.1	178.5	183.7	848.5

Source: TransGrid, *Revenue proposal*, p. 96.
Note: Totals may not add up due to rounding.

5.3.1 Opex forecasting methodology

TransGrid has developed an opex model to forecast controllable operating costs and specific forecasts for other or non-controllable operating costs (debt raising, equity raising, self insurance and network support costs).

TransGrid used 2006–07 as its base year opex to forecast future opex requirements. TransGrid made adjustments for a number of one off or unusual expenses so that the starting base for the forecast reflects the expected cost base for future years. Section 5.6.2 discusses the base year proposed by TransGrid in more detail.

The opex model escalates base year values to reflect the impact of real costs and the growth of assets proposed to be commissioned during the next regulatory control period.[224]

[224] TransGrid, *Revenue proposal*, pp. 84–85.

TransGrid has applied economy of scale factors to its forecast opex to recognise the impact of additional assets on operating costs is not one-to-one.[225]

In addition an opex/capex trade off is incorporated into the model by reducing the forecast maintenance effort by the hours identified as being saved by the implementation of the proposed asset replacement program.

TransGrid stated that some opex categories are better estimated from a zero base, or using a bottom up approach. Accordingly, it developed zero based (bottom up) forecasts for: [226]

- maintenance (this includes all field based activities for routine maintenance, defect maintenance and major operating projects such as plant refurbishment)
- insurance
- debt raising
- equity raising
- self insurance
- network support.

Section 5.6.7 discusses the non-controllable opex components in more detail.

5.3.2 Escalators

The costs included in the base year 2006–07 opex have been escalated to provide forecast opex for the next regulatory control period. TransGrid obtained advice from the Competition Economists Group (CEG) on annual labour cost escalators for the electricity, gas and water (EGW) or utility sector in NSW.[227]

TransGrid proposed that non-labour costs included in the forecast opex be escalated using CPI.[228]

Section 5.6.4 discusses the escalators in more detail.

5.4 Submissions

The following stakeholders made submissions on the opex component of TransGrid's revenue proposal:

- Energy Markets Reform Forum (EMRF)
- Energy Users Association of Australia (EUAA)
- Norske Skog Albury Mill (Norske Skog).

[225] TransGrid, *Revenue proposal*, p. 87.
[226] TransGrid, *Development of TransGrid opex model*, pp. 7, 9, 14, confidential.
[227] CEG, *NSW electricity businesses*.
[228] TransGrid, *Revenue proposal*, p. 90.

These submissions are summarised in general below and where relevant in specific sections of the opex chapter.

The EMRF stated TransGrid should make opex efficiency gains.[229] The EUAA raised concerns that TransGrid's proposed forecast opex does not meet the opex criteria outlined in clause 6A of the NER.[230]

The EMRF considered that there is no basis for escalating TransGrid's proposed opex for expected wages growth, as there is no step change in wages growth between the current and next regulatory control periods.[231]

The EUAA stated that while the benchmarking reports[232] provided by TransGrid may be useful to assess TransGrid's current level of opex, the reports did not assess the proposed increase in opex of 33.7 per cent. The EUAA noted that it would prefer that independent benchmarking became a feature of the regulatory regime applied by the AER. It submitted that the AER should establish an independent benchmarking project overseen by a committee of network businesses and end users.[233]

The EUAA noted that TransGrid's base year of 2006–07 appears to feature opex 3.6 per cent higher (when measured in $2007–08) than 2007–08 and 3 per cent higher than the estimated opex for 2008–09. It submitted that the AER should investigate the appropriateness of using a more current base year. [234]

The EUAA was concerned that TransGrid had not provided any cost–benefit data to justify the trade–off between asset maintenance and asset renewal.[235]

The EUAA expressed a number of concerns with the pass through provisions related to network support events. It submitted that the AER should implement measures to ensure that cost reductions are passed through to customers.[236]

Both the EUAA and Norske Skog submitted that the AER should apply the rigour of the competitive market in assessing any pass through cost applications.[237]

5.5 Consultant review

PB reviewed TransGrid's revenue proposal, including TransGrid's forecast opex, forecasting methodology (including base year extrapolation and zero base estimates) and network support forecasts.[238]

---

229 EMRF, p. 20.
230 EUAA, p. 28.
231 EMRF, p. 23.
232 TransGrid, *Revenue proposal*, appendix K.
233 EUAA, p. 28–29.
234 EUAA, p. 29.
235 EUAA, p. 16.
236 EUAA, pp. 32–34.
237 EUAA, pp. 32–34; and
Norske Skog Albury Mill, *Submission to the Australian Energy Regulatory TransGrid Revenue Proposal 2009/10 to 2013/14*, 26 August 2008, p. 4.
238 PB, pp. 190–227.

PB reviewed and analysed the following matters in relation to the contribution of opex forecasts to TransGrid's delivery of prescribed transmission services:

- the efficiency of TransGrid's forecast opex for each year of the next regulatory control period and whether there exists any scope for further efficiencies
- the appropriateness of TransGrid's allocation of opex costs to specific activities, including the distinctions between regulated and non-regulated activities; routine maintenance and refurbishments/renewals; and the treatment of joint and common costs such as corporate administration expenses and financing charges
- the effectiveness of TransGrid's operating practices and procedures and asset management system in ensuring only necessary and efficient opex occurs
- the key internal and external factors that may affect the level of efficient opex required by TransGrid over the next regulatory control period
- the appropriateness of TransGrid's methodology to forecast its opex requirements
- the appropriateness of any trade-off between capex and opex.

Overall, PB concluded that TransGrid's opex model and its inputs (with the inclusion of two recommended adjustments) incorporated assumptions and forecasting methodologies that produce reasonable forecasts of opex for the next regulatory control period.[239]

PB noted that TransGrid's asset management process uses condition monitoring and condition based replacement triggers to maximise the life of the assets. PB concluded that TransGrid's asset management process was consistent with good industry practice. Further, PB stated that TransGrid has well structured and well documented policies and processes to support the provision of its transmission services that are consistent with good industry practice.[240]

During the review of TransGrid's revenue proposal, four issues were identified by PB that had an impact on the forecast opex and which TransGrid and PB agreed should be incorporated into the opex model. These were:[241]

- TransGrid had originally used a CPI forecast of 3.25 per cent for 2007−08. TransGrid advised that the actual CPI inflation rate of 4.24 per cent (March 2007 to March 2008 quarters are taken as a proxy for 2007−08) was available and should be used for the opex forecast.[242] This CPI is used to convert nominal dollars to $2007−08 and to convert the 2006−07 base year opex to $2007−08.

  TransGrid also advised that asset growth factors are applied to asset categories in the opex model to take effect in the year after commissioning of new assets. TransGrid stated that this methodology was applied correctly to maintenance opex categories, but was incorrectly applied to non-maintenance opex categories.

239 PB, pp. 247–251.
240 PB, pp. 38–41.
241 PB, pp. 191–195.
242 TransGrid, response to information request no. 18, confidential, 23 July 2008.

The combined effect of these two amendments is an increase in total forecast opex over the next regulatory control period of $1.9 million ($2007–08).

- TransGrid engaged Willis Risk Practice Australia to conduct an independent review of its insurance arrangements. TransGrid amended its forecast opex to correct for the consolidation of information from the Willis Risk Practice report transposed to TransGrid's opex model and to update the approximation of the 2006–07 replacement value of assets.[243] The value of secondary systems was increased by 19 per cent, substations increased by 0.7 per cent, and land and easements decreased by 0.7 per cent. These amendments resulted in a reduction of $0.8 million ($2007–08) to TransGrid's forecast opex.

- TransGrid advised that costs relating to insurance events should be removed from the base year because these costs have been determined on a zero based approach. TransGrid agreed to remove insurance costs from the base year, provided sufficient provision was made for a self insurance allowance as proposed by it.[244] TransGrid also updated the opex model to rectify two minor inconsistencies.[245] These amendments resulted in a reduction of $22 million ($2007–08) to TransGrid's forecast opex.

- TransGrid has included an allowance of $1 million per annum in its revenue proposal for demand management initiatives. In the opex model, this allowance was escalated by the proposed asset growth factor and also escalated from $2006–07 to $2007–08. PB did not consider that this approach was reasonable, but recognised that the labour component of the allowance should be escalated to reflect real increases in labour costs.[246] PB also noted that the allowance was already in 2007−08 dollar terms. TransGrid agreed to only escalate the demand management allowance for increases in real wage costs.[247] This amendment resulted in a reduction of $0.3 million ($2007–08) to TransGrid's forecast opex.

Table 5.2 compares the original forecast controllable opex put forward by TransGrid in its revenue proposal with the agreed updated forecast controllable opex. PB's additional recommendations are based on the updated forecast opex. The net impact of the agreed adjustments reduced TransGrid's forecast controllable opex by $23 million ($2007–08).

243 TransGrid, response to information request no. 92, confidential, 21 July 2008.
244 TransGrid, response to information request no. 22B, confidential, 23 July 2008.
245 TransGrid provided an updated Effective Asset Growth spreadsheet which used actual CPI for 2007–08 to convert 2008 dollars to 2007 dollars to calculate effective asset growth and also corrected a calculation of the unit rates for Major Operating Projects.
246 PB, pp. 194–195.
247 TransGrid, response to information request no. 148, confidential, 5 August 2008.

Table 5.2: TransGrid's original and updated forecast controllable opex ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Original forecast opex	135.2	144.4	149.7	161.8	166.5	757.6
Updated forecast opex	131.5	140.6	144.9	156.5	161.5	735.1
Variation	3.7	3.8	4.8	5.2	5.00	22.6

Source: TransGrid, *Revenue proposal*, p. 90; TransGrid opex model version 4.5(a).
Note: Figures may not add due to rounding.

In addition to these agreed adjustments PB recommended two adjustments to TransGrid's forecast opex. Both of these adjustments relate to how TransGrid has modelled the impact of new assets to develop its forecast opex. These adjustments related to recalculating the current replacement cost of TransGrid's asset base and removing the forecast defect maintenance costs associated with assets proposed to be commissioned during the next regulatory control period.[248]

PB also recommended a small amendment to TransGrid's proposed self insurance allowance.[249]

With these adjustments, PB considered that the (adjusted) opex represents an efficient level of opex required for the next regulatory control period.[250]

Table 5.3 sets out PB's recommendations for TransGrid's opex allowance for the next regulatory control period. PB's recommended adjustments reduce TransGrid's forecast opex by $39 million ($2007–08).[251] The recommendations are discussed in detail in section 5.6.5.

[248] PB, pp. 221–226.
[249] PB, pp. 214–219.
[250] PB, pp. 247–251.
[251] PB, p. 227.

Table 5.3: PB's recommendations for TransGrid's forecast opex ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's proposed controllable opex	135.2	144.4	149.7	161.8	166.5	757.6
Debt raising	3.7	4.0	4.3	4.8	5.1	21.9
Equity raising	0.9	1.7	3.1	4.0	4.2	13.9
Self insurance	1.9	1.9	1.9	1.9	1.9	9.6
Network support	21.5	6.0	6.0	6.0	6.0	45.5
TransGrid's proposed total opex	163.2	158.0	165.0	178.5	183.7	848.4
PB's adjustments to controllable opex	131.2	137.0	140.6	150.3	153.9	712.9
Debt raising[a]	3.7	4.0	4.3	4.8	5.1	21.9
Equity raising[a]	0.9	1.7	3.1	4.0	4.2	13.9
Adjusted self insurance	3.1	3.1	3.1	3.1	3.1	15.7
Network support	21.5	6.0	6.0	6.0	6.0	45.5
PB's recommended total opex	160.4	151.8	157.1	168.2	172.4	809.9

(a) Total opex includes debt and equity raising costs that were not assessed by PB.
Note: Totals may not add due to rounding.
Source: PB report, p. 227.

5.6 Issues and AER considerations

5.6.1 TransGrid forecasting methodology

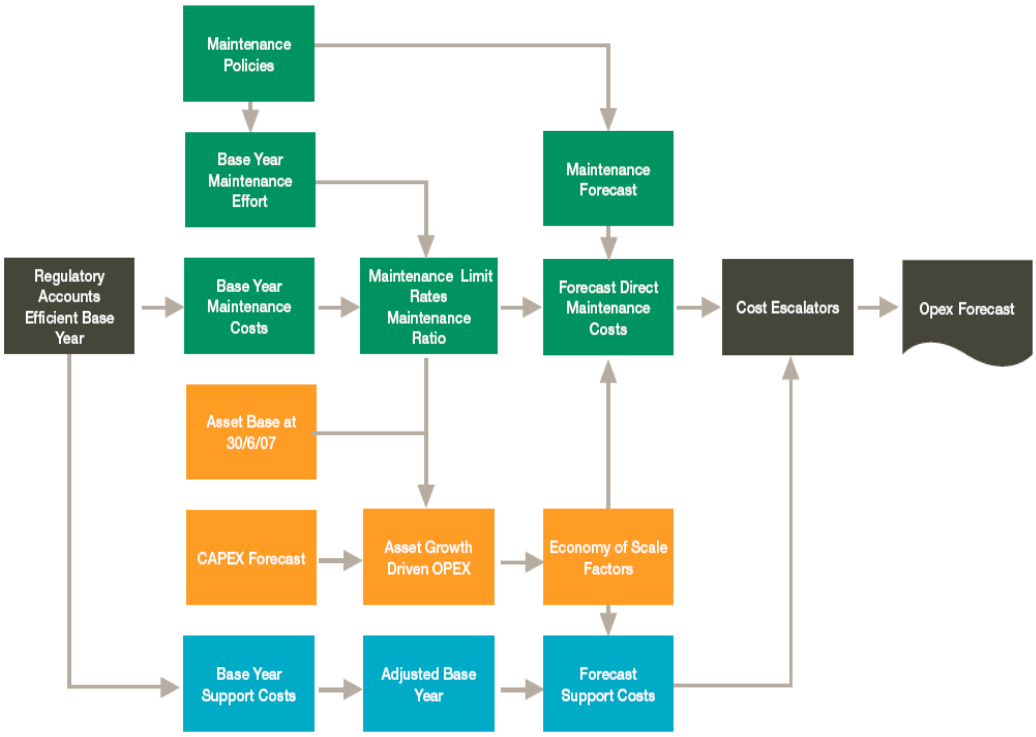
TransGrid proposal

The TransGrid opex model escalates the 2006−07 base year values to reflect the impact of real cost drivers and the growth of assets arising from TransGrid's proposed capex program for the next regulatory control period.[252] This is done by determining the maintenance unit rates, ratios and maintenance effort from the base year costs and records, and escalating these values to reflect the impact of asset growth and real increases in costs.

The maintenance forecasts in the opex model are built up from a zero base. TransGrid advised that this approach allows the maintenance forecasts to reflect cyclical requirements and adjustments for changes in scope when assets are replaced with new equipment that requires less maintenance.[253] TransGrid's method for forecasting its controllable opex is summarised in figure 5.2.

[252] TransGrid, *Revenue proposal*, p. 84.
[253] TransGrid, *Revenue proposal*, p. 86.

Figure 5.2: TransGrid's model for forecasting controllable operating expenditure



Source: TransGrid, *Revenue proposal*, p. 84.

Other categories of opex including insurance, debt raising, equity raising, self insurance and network support costs are also developed using a zero based forecast.

Economy of scale factors are incorporated to reflect the expected efficiencies TransGrid should be able to achieve in performing additional work during the next regulatory control period. In addition, an opex/capex trade off is incorporated into the model and results in savings to the forecast maintenance effort due to the implementation of the proposed asset replacement program.[254]

TransGrid also made adjustments for a number of unusual or one off expenses which are expected to be incurred during the next regulatory control period. These one off expenses have either been deducted or added to the relevant year in the next regulatory control period, as these expenses are not incurred in every year of the next regulatory control period. TransGrid has also removed one off or unusual expenses from the base year.

Consultant review

PB considered that TransGrid's opex model incorporates assumptions and forecasting methodologies that produce reasonable forecasts of opex. A number of adjustments were also identified and agreed to by TransGrid, which impacted on the forecast opex.[255]

254 TransGrid, *Revenue proposal*, pp. 86–87.
255 PB, p. 198.

AER considerations

Based on PB's advice the AER considers that TransGrid has provided a robust methodology for forecasting its opex requirement for the next regulatory control period. In particular, the AER notes that:

- TransGrid's methodology is broadly similar to that applied by other TNSPs and considered in previous transmission determinations
- the assumptions incorporated into the opex model are reasonable—including the use of zero base forecasts for some opex components as well as extrapolation of base year opex for the remaining opex categories
- adjustments for unusual expenses or one off expenses have appropriately been made to the base year and to the relevant year in the next regulatory control period
- corrections for and other adjustments identified during the review process have been agreed to. The AER considers these adjustments (e.g. update for actual CPI where available and correction for transposition/formula errors) provide an updated forecast opex which is an appropriate proposal for review.

5.6.2 Efficient base year

TransGrid proposal

TransGrid used 2006–07 as the base year for forecasting opex in the next regulatory control period. TransGrid stated that it selected 2006–07 as the base year because it is the most recent year for which audited financial accounts are available. Further, TransGrid regarded its opex in 2006–07 as being efficient because it has met the efficiency target of 2 per cent per year for the 2004–05 to 2006–07 period.[256] This efficiency target was provided for in the ACCC's 2005 revenue cap decision for the current regulatory control period.[257] TransGrid also relied on a number of benchmarking reports to demonstrate the efficiency of the 2006–07 base year.

Table 5.4 outlines the opex allowance provided for in the ACCC's 2005 revenue cap decision and TransGrid's actual and expected opex for the current regulatory control period.[258]

Table 5.4: Actual and allowed controllable opex for 2004–05 to 2008–09 ($m, 2007–08)

	2004–05	2005–06	2006–07	2007–08	2008–09	Total
ACCC revenue cap decision	131.6	131.1	130.7	130.3	130.2	654.0
TransGrid's actual/forecast opex	128.9	128.9	128.3	123.9	124.6	634.7
Difference	–2.7	–2.2	–2.4	–6.4	–5.7	–19.3

Source: TransGrid, *Revenue proposal*, p. 45.

256 TransGrid, *Revenue proposal*, p. 85.
257 ACCC, *TransGrid final decision*, p. 50.
258 Excludes non-controllable opex such as network support costs.

TransGrid advised that its opex for the current regulatory control period is expected to be below the allowance provided for in the ACCC's 2005 revenue cap decision due to two factors:[259]

- Cost reduction program across TransGrid's normal business activities—TransGrid advised that the cost reduction program included a review of work processes across the organisation and the introduction of process improvements. It stated that initiatives put in place to achieve these efficiencies included a review of the control room shift arrangements leading to a reduction in staff, centralisation of support functions and rationalisation of the IT outsourcing arrangements. These initiatives have resulted in the expected opex being slightly below the approved opex allowance.

- Superannuation holiday—TransGrid was not required to make contributions to the defined benefits and retirement superannuation schemes in 2007–08 or 2008–09 due to the strong performance of the schemes in the preceding years. This has or will result in abnormal reductions in opex for both 2007–08 and 2008–09. Superannuation contributions have been included as a scope change in the opex model.

During the review of TransGrid's revenue proposal, TransGrid advised that the actual opex for 2007–08 was $120 million ($2007–08).[260] The actual opex for 2007–08 is lower than the forecast originally provided in TransGrid's revenue proposal, largely because of the superannuation contribution which TransGrid has not been required to make.

TransGrid has determined a number of expenses in the 2006–07 base year to be unusual or one off expenses. TransGrid has made adjustments for these one off or unusual expenses so that the base year reflects costs from which future opex forecasts can be made. TransGrid has deducted the following expenses from its base year:

- deferred and reduced payment of licences associated with repeater sites

- the implementation costs of a virtual control room which has resulted in a reduction of staff required in future years

- expenses relating to a number of pass through projects incurred in 2006–07. These expenses have been removed from the base year and zero based forecasts are reflected in the network support category for the next regulatory control period

- demand side management programs—costs for the next regulatory control period have been calculated on a zero based approach

- insurance costs—the forecasts are calculated on a zero based approach

- revenue reset costs—the forecasts are calculated using a zero based approach

[259] TransGrid, *Revenue proposal*, p. 46.
[260] TransGrid, response to information request, confidential, 17 October 2008.

- savings associated with the rationalisation of outsourced IT services have been included.[261]

In total these one off or unusual expenses resulted in a reduction to the 2006–07 audited opex of $9.7 million ($2007–08). In addition, the agreed adjustments made to TransGrid's opex model also had an impact on the calculation of the 2006–07 base year costs. Consequently, the total audited 2006–07 opex for modelling purposes has been reduced by $12 million ($2007–08) to remove all one off or unusual costs.[262]

Submissions

The EUAA stated that while the benchmarking reports provided by TransGrid may be useful to assess TransGrid's current level of opex, the reports did not assess the proposed increase in opex of 34 per cent. The EUAA stated that the AER should request TransGrid to demonstrate how the results of the benchmarking surveys would vary should TransGrid's opex increase by 34 per cent.[263]

The EUAA noted that it would prefer that independent benchmarking became a feature of the regulatory regime applied by the AER. It submitted that the AER should establish an independent benchmarking project overseen by a committee of network businesses and end users.[264]

The EUAA submitted that the 2006–07 base year appears to feature higher operating costs, when measured in 2008 dollar terms. The EUAA noted that the actual operating costs were 3.6 per cent higher in 2006–07, than for 2007–08 and 3 per cent higher than the projected opex for 2008–09.[265]

Consultant review

PB assessed the efficiency of TransGrid's base year costs by considering the following:

- TransGrid's opex performance during the current regulatory control period.

- ITOMS benchmarking results.[266] TransGrid has participated in this benchmarking exercise for 13 years.[267] PB noted that the ITOMS benchmarking study is held in high regard by market participants and the normalisation factors have been developed over an extended period of time. PB considered that the ITOMS benchmarking study provides a reasonable insight into the relative efficiency of the study participants. The results of the ITOMS survey suggest to PB that TransGrid is a low cost provider that achieves high service levels.[268]

---

261 TransGrid, *Development of TransGrid opex model*, pp. 9–10, confidential.
262 PB, p. 204.
263 EUAA, pp. 28–29.
264 EUAA, p. 29.
265 EUAA, p. 29.
266 ITOMS, *International Transmission Operations and Maintenance Study, 2007 Report*, revision date 13 January 2008.
267 TransGrid, *Revenue proposal*, p. 39.
268 PB, pp. 205–206.

- A report prepared by Sinclair Knight Merz (SKM).[269] SKM was engaged by TransGrid to review its operating cost model inputs which included a high level review of TransGrid's maintenance policies and resource allocation to standard maintenance tasks. The report by SKM concluded that TransGrid's maintenance 'policies attempt to provide for a minimisation of maintenance whilst maintaining and achieving the corporate objectives of safety reliability, security and the availability of the network within a quality management framework'.[270] Further, SKM stated that the 'policies are up to date and incorporate maintenance activities that are practiced through the industry'.[271] PB noted that SKM's high level review of TransGrid's resource allocation suggested that TransGrid's performance could be considered reasonable and efficient.[272]

- A report prepared by the UMS Group (UMS).[273] UMS was engaged by TransGrid to provide an overall assessment of its operating efficiency. UMS assessed TransGrid's performance against twelve other comparable transmission businesses around the world, including four based in Australia. The results from the UMS report showed that TransGrid's operational efficiency is excellent by international standards and is better than average when comparing TransGrid with domestic TNSPs. PB concluded that the results of the UMS report indicate that TransGrid is a low cost provider of transmission services.[274]

Overall, PB concluded that the 2006–07 base year represents a reasonable expenditure from which to project future forecast opex requirement.[275]

AER considerations

The AER is satisfied that TransGrid's base year is representative of efficient expenditure from which to project its forecast opex requirements.

In forming this view the AER notes PB's advice that the ITOMS benchmarking survey, the SKM report and the UMS report suggest that TransGrid is currently a prudent and efficient provider of transmission network services.

The AER notes the concern expressed by the EUAA that the benchmarking studies only provide insight into how TransGrid's historical operating costs compare with the relevant benchmark. The AER considers that such a comparison is relevant as it provides some measure of whether the base year from which opex is forecast is representative of efficient expenditure by a TNSP. There is some merit in establishing independent benchmarking project as this may assist in considering opex allowances for future revenue proposals.

The AER also notes the concern expressed by the EUAA that the 2006–07 year features higher opex than the actual or expected opex for 2007–08 and 2008–09. TransGrid proposed using the 2006–07 year as the base year because it was the most recent year for which audited financial accounts were available. The AER considers

269 SKM, *Review of TransGrid's Operating Cost Model Inputs*, 29 May 2008.
270 SKM, p. 1.
271 SKM, p. 1.
272 PB, p. 207.
273 UMS Group, *TransGrid Transmission Efficiency Review*, 8 May 2008.
274 PB, pp. 207–208.
275 PB, p. 208.

that the alternative of using more recent data, that has not been audited, increases the likelihood of inaccuracies being introduced to the opex forecasts for the next regulatory control period. Further, the AER notes that the opex for 2007–08 and 2008–09 is or is expected to be abnormally low because of the superannuation holiday which TransGrid has experienced. Therefore, the savings TransGrid has experienced from the superannuation holiday are unusual and are not expected to be achieved in the next regulatory control period.

The AER considers that where the proposed base year actual expenditure is close to or less than the efficient allowance provided in the previous revenue cap decision, it is reasonable to accept the base year as an efficient starting point. During the current regulatory control period TransGrid has implemented opex efficiencies such that the actual controllable opex for 2006–07 is lower than the allowance provided by the ACCC in its 2005 revenue cap decision (table 5.4).

Further, the AER is satisfied that TransGrid has appropriately removed one off or unusual expenses from the base year. Removing one off or unusual expenses from the 2006–07 year, reduces the base year opex by $12 million ($2007–08).

Overall, the AER is satisfied that the base year proposed by TransGrid is reasonable and reflects efficient costs from which to project TransGrid's forecast opex requirements.

5.6.3 Controllable opex

Controllable opex components

TransGrid proposal

TransGrid's opex model incorporates the following controllable opex categories:[276]

- maintenance—this includes all field-based maintenance activities such as routine and defect maintenance and major operating projects
- maintenance support and asset management—this includes the management of field-based maintenance teams, asset management and the costs of running business systems that directly support field maintenance activities
- operations—this includes the costs associated with TransGrid's around-the-clock state system control and regional control functions which also includes real-time control room operation, operations planning, system performance and operating facilities
- grid planning—this includes costs associated with planning for the development of the transmission network. The functions under this category include grid planning, system analysis, market and scenario modelling, load forecasting, NER regulatory consultation and the production of the NSW Annual Planning Report
- taxes and insurance—this is the costs associated with taxes paid to external authorities and costs for the insurance of TransGrid's assets

[276] TransGrid, *Revenue proposal*, p. 90.

- property management—this includes the cost associated with the ongoing management of property and issues related to easements and environmental compliance

- corporate and regulatory management—this includes the functions responsible for corporate governance, customer relations and regulatory affairs. This category also includes an allowance for demand management initiatives which is discussed below

- business management—this includes the costs associated with business administration, such as human resources, payroll functions, finance, accounting and IT.

Each of these opex categories is forecast using base year values in the opex model, except for maintenance and insurance costs which are zero based.

Consultant review

PB reviewed the underlying forecasts of TransGrid's controllable opex categories and concluded that these forecasts were reasonable.

PB noted that a number of forecasts for controllable opex include efficiency initiatives. For example, the forecast for grid planning incorporates the decision not to replace one managerial position and the progressive transition from 'in-house' software to proprietary software which is expected to free up staff from software support functions. The property management forecast incorporates a 2 per cent saving in the head office lease management fee, a reduction in rental outgoings for repeater station licences and a restructure of leasing arrangements for TransGrid's head office.

In reviewing the controllable opex components PB also noted that the increase in opex is largely a result of escalation for real labour costs.

Overall, PB identified no issues with the underlying forecasts for the controllable opex categories. However, PB recommended two adjustments be made to how asset growth is applied to the controllable opex categories.[277] These recommended adjustments are discussed in section 5.6.5.

AER considerations

Based on PB's advice, the AER agrees that TransGrid has developed appropriate underlying forecasts for its controllable opex. The AER, however, considers that the proposed asset growth and labour cost escalations applied to these underlying forecasts will not result in a total controllable opex that represents the efficient costs that a prudent operator in the circumstances of TransGrid's would require to achieve the opex objectives in the next regulatory control period.

The AER's consideration of the appropriateness of how labour cost and asset growth escalations are applied in the opex model is discussed further in sections 5.6.4 and 5.6.5.

[277] PB, pp. 221–226.

Demand management allowance

TransGrid proposal

TransGrid has proposed an allowance of $1 million per annum ($2007–08) to develop and investigate demand side management responses to emerging constraints in the transmission system. This allowance is included under the corporate and regulatory management opex category.

TransGrid stated that it has been working with EnergyAustralia on the Demand Management and Planning Project (DMPP), which was established by the NSW Department of Planning in March 2002, and completed in June 2008. The objective of the DMPP was to identify potential opportunities to reduce consumer peak demand for electricity in the inner Sydney region.[278] The DMPP gathered information on opportunities for reducing demand at more than 700 sites in the Sydney CBD and inner suburbs.[279]

TransGrid stated that, using the results obtained from the DMPP, it is proposing to implement a number of demand management programs involving various customer classes over the next regulatory control period. TransGrid noted that these demand management initiatives will be implemented in conjunction with the NSW DNSPs, via Memorandum of Understandings.[280]

TransGrid submitted that its proposed demand management allowance would allow it to better understand and give consideration to non-network alternatives, and to meet new obligations under the regulatory test that require TNSPs to consider non-network alternatives.[281]

Submissions

The EUAA stated that it welcomes TransGrid's planned demand side management initiatives. However, in its view the DMPP has achieved very little return for the money invested. The EUAA submitted that the DMPP should be reviewed to quantify the benefits received, particularly given TransGrid's proposed capex requirements for the next regulatory control period.[282]

Consultant review

PB considered that TransGrid's specific experience in aggregating smaller demand management projects, such as load shedding and small scale generation, should enable practical proposals to be developed outside of the Sydney metropolitan area. PB noted that TransGrid has already put in place memorandum of understandings on joint demand management projects with the NSW DNSPs.

---

278 TransGrid, *Revenue proposal*, p. 31; and
NSW Department of Planning, Demand Management and Planning Project, Project Background, <http://www.planning.nsw.gov.au/dmpp/reports.asp>.

279 The results of the DMPP are available on the NSW Department of Planning website, <www.planning.nsw.gov.au/dmpp>.

280 TransGrid, response to AER information request no. 146, confidential, 7 August 2008.

281 TransGrid, *Demand management innovation: Need and proposal*, position paper, July 2008, pp. 8–10.

282 EUAA, p. 19.

PB concluded that the proposed demand management allowance is reasonable and that it is likely to result in additional demand management programs being implemented over the next regulatory control period.[283]

AER considerations

The AER notes that this is the first time that TransGrid has proposed an allowance for demand management initiatives within a revenue proposal. The AER considers it is prudent and reasonable for TNSPs to investigate opportunities for efficient non-network alternatives to network augmentation.

The AER considers that the proposed demand management allowance of $1 million per annum will allow TransGrid (in conjunction with the NSW DNSPs) to implement and build upon the results obtained from the DMPP. The AER notes that demand management incentive schemes are included as part of the regulatory framework for DNSPs. Under these schemes the NSW DNSPs are provided with a demand management incentive allowance.

TransGrid's proposed demand allowance would also allow it to investigate and implement a number of small scale demand management projects, which in the long-term may provide efficient alternatives to network augmentation in areas where there are peak demand constraints. Demand management should be implemented by a TNSP where it is an efficient response to network constraints.

The AER considers that information on expenditure and outcomes of demand management initiatives is valuable in determining the reliability and viability of non-network alternatives for future transmission determinations. The demand management incentive schemes established for the NSW DNSPs impose reporting obligations on the DNSPs, which must be met in order for the demand management cost recover to occur under the schemes.[284] To assist the AER's understanding of the outcomes TransGrid is seeking to achieve from the proposed demand management incentive allowance and to provide increased transparency and accountability, the AER will request information from TransGrid on how the allowance was spent, and on the outcomes of the initiatives implemented during each year of the next regulatory control period. The AER may also request further information on this matter as part of its preparations for the 2014 transmission determination process.

Overall, the AER considers that the demand management allowance reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

5.6.4 Cost escalators

Labour costs

TransGrid proposal

TransGrid stated that the utilities sector has experienced above average wage growth in the past 20 years. TransGrid stated that this is expected to continue due to a tight

[283] PB, p. 201.

[284] AER, *Final Decision*: *Demand management incentives schemes for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008.

labour market in the electricity sector. Accordingly, TransGrid has used real escalation rates for labour in calculating its forecast opex.[285]

TransGrid obtained advice from CEG on forecast annual labour escalation rates.[286] CEG recommended that averaging the escalation rates calculated by Econtech[287] and Macromonitor[288] provides an appropriate forecast of labour cost escalators for the EGW or utility sector in NSW.[289] The average labour cost escalators adopted by TransGrid for its forecast opex are set out in table 5.5.

Table 5.5: CEG's real labour cost growth rates for the NSW EGW sector (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Econtech (Aus wide)	2.0	2.8	5.6	5.0	3.9	3.4	3.1
Macromonitor (NSW)[a]	4.2	4.4	2.3	–1.2	1.7	3.7	4.2
NSW average	3.1	3.6	3.9	1.9	2.8	3.5	3.7

Source: TransGrid, *Revenue proposal*, p. 90.
(a) Productivity adjusted.

Submissions

The EMRF noted that TransGrid has been experiencing a premium of wages growth over the average wage growth in the current regulatory control period (which is equivalent to the wage forecast recommended by CEG). However, the EMRF stated that at the same time, TransGrid had been able to reduce or constrain its opex. The EMRF considered that this implies that there is no basis for escalating TransGrid's proposed opex for expected wages growth, as there is no step change in wages growth between the current and next regulatory control periods.[290]

Consultants review

PB

PB suggested that the EGW labour escalator proposed by TransGrid should be reviewed prior to the AER making its decision, given the current volatile economic environment.[291]

PB considered that TransGrid's application of the EGW labour escalators to relevant components in the opex model was reasonable.[292]

[285] TransGrid, *Revenue proposal*, p. 89.
[286] CEG, *NSW electricity businesses*.
[287] Econtech, *Labour cost growth forecasts,* 13 August 2007, Attachment D.
[288] Macromonitor, *Forecasts of cost indicators for the electricity transmission sector, New South Wales & Tasmania*, February 2008.
[289] CEG, *NSW electricity businesses*, p. 8.
[290] EMRF, p. 23.
[291] PB, p. 209.
[292] PB, pp. 209–210.

Econtech

The AER engaged Econtech to provide advice on wage forecasts for the EGW sector in NSW. In preparing its labour cost forecasts, Econtech took account of the latest available wage data. Econtech also reviewed the CEG methodology for forecasting labour cost growth rates in the EGW sector and concluded that the averaging approach used by CEG was not reasonable.[293]

Econtech's forecasts for labour cost growth rates in the EGW sector in NSW for the next regulatory control period is shown in table 5.6 and outlined in further detail in appendix C.

Table 5.6: Econtech's real labour cost growth rates for the NSW EGW sector (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
NSW	1.2	2.8	3.9	3.4	3.0	2.8	2.1

Source: Econtech, *Forecasts of labour cost growth forecasts,* Appendix D, p. 10.

AER considerations

Labour cost growth rates

The AER considers that where there are real cost increases which are beyond the reasonable control of TNSPs, such cost increases should be factored into a TNSP's revenue proposal to reflect the efficient costs that a prudent operator would require to achieve the opex objectives. In the case of labour, the AER recognises that the shortage of skilled workers in the EGW sector is likely to continue to drive labour costs above CPI in the next regulatory control period.[294] Accordingly, the AER considers that TransGrid's opex forecast should take into account the real increase expected in wages growth in the NSW EGW sector.

The details of the AER's assessment of the labour cost forecasts proposed by TransGrid are set out in appendix C.

Based on Econtech's advice the AER does not consider that the averaging methodology employed by CEG to forecast wages growth in the EGW sector for NSW is sufficiently robust. In particular, the AER notes Econtech's advice that the Macromonitor and Econtech forecasts are not comparable and that averaging the two forecasts is methodologically unsound and likely to provide inappropriate forecasts of labour cost escalation.

Further, the AER does not consider that the CEG proposed labour cost growth rates are a reasonable reflection of the likely future labour costs as they are not based on the most recent information. The AER notes Econtech's advice that since it provided forecasts of labour cost growth rates to the AER in August 2007 (which was used by

[293] Econtech, *Labour cost growth forecasts 2007/08 to 20016/17, 19 September 2008,* pp. 39–42.
[294] Econtech, *Labour cost growth forecasts*, pp. 36−37.

CEG), the economic climate has changed considerably, resulting in some pressure being taken off wages growth.[295]

For these reasons the AER does not consider CEG's proposed labour cost growth rates for the EGW sector in NSW provide reasonable inputs to deriving the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

From 2008–09 the AER will adopt Econtech's forecasts for wages growth in the EGW sector in NSW for the next regulatory control period. The AER considers that the application of the Econtech forecasts for wages growth in the EGW sector for NSW reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c). Given that actual wage data is available for 2007–08, the AER will apply the actual wage increase provided for under TransGrid's current work place award.

The EGW labour cost growth forecasts the AER will apply to TransGrid's opex for the next regulatory control period are shown in table 5.7. As a result of applying these labour cost growth forecasts, the AER has reduced TransGrid's forecast controllable opex by $11 million ($2007–08).

Table 5.7: AER's conclusion on NSW EGW real labour growth rates (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
AER's labour rates	0.5[a]	2.8	3.9	3.4	3.0	2.8	2.1

Source: Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, appendix D, p. 10.
(a) The AER derived the real award rate by using the actual CPI for 2007–08 of 4.5 per cent.

Application of labour cost growth rates

The AER notes TransGrid has outsourced contracts for a number of services included in its forecast opex (e.g. vegetation maintenance and services related to corporate support). It has not applied escalation for wages growth while rates under these contracts are locked in.

In general, the AER accepts the application of wage rates included in contracts which are negotiated through a commercial tender process. Further, the AER accepts the application of labour cost growth rates which reflect the specific circumstance of the service which is being provided. For example, the AER would expect a general wage escalator to be applied to services which are not related to the EGW sector.

Overall, based on the information provided, the AER considers that the labour cost growth rates applied by TransGrid in its opex model (subject to the updated Econtech labour cost growth rates being used) reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

[295] Econtech, *Labour cost growth forecasts,* p. 24.

Non-labour costs

TransGrid proposal

TransGrid proposed the use of CPI to escalate the non-labour component of its opex forecasts.[296]

AER considerations

The AER considers that TransGrid's proposed approach of using CPI as escalators—that is, no real increase—for its non-labour opex components to be reasonable, as the approach is consistent with past regulatory practice.

The AER considers that the use of CPI as an escalator for the non–labour component of TransGrid's opex reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c). The AER therefore accepts TransGrid's proposed approach.

5.6.5 Asset growth

Impact of updated capex forecast

During the course of the review of TransGrid's revenue proposal, TransGrid published its 2008 Annual Planning Report (2008 APR) which includes a revised load forecast.[297] The 2008 APR has resulted in a reduction of $77 million ($2007–08) to TransGrid's forecast capex proposal for the next regulatory control period. The AER has also made further adjustments to TransGrid's forecast capex which has reduced the forecast capex allowance to $2376 million.

The asset growth in TransGrid's opex model has been adjusted to incorporate the impact of the 2008 APR outcomes and also the AER changes to the forecast capex allowance. The revised asset growth values are shown in table 5.8 and have been applied in the opex model to derive controllable opex forecasts. The impact of the 2008 APR and the AER changes to the forecast capex allowance reduced the forecast controllable opex by $1.3 million ($2007–08).

Table 5.8: Adjusted asset growth ($m, 2006–07)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Transmission lines	81.3	41.1	113.3	262.8	9.8	508.3
Substations	384.8	56.2	65.0	174.5	45.0	725.5
Communications	25.3	4.9	8.1	4.4	9.3	51.9
Secondary systems	18.3	10.8	8.1	5.7	2.1	45.0
Land and easements	27.2	5.5	85.2	44.9	55.9	218.6
Total	536.8	118.5	279.7	492.2	122.1	1549.2

Source: TransGrid opex model version 6.2.
Note: Totals may not add up due to rounding.

[296] TransGrid, *Revenue proposal*, p. 90.
[297] TransGrid's revenue proposal was based on capex developed using the 2007 APR load forecasts.

2006–07 replacement cost of asset base

TransGrid proposal

TransGrid has proposed a significant capex program for the next regulatory control period. If approved, this will increase the asset base considerably.

TransGrid's opex model calculates the additional opex required to operate and maintain new assets proposed to be commissioned during the next regulatory control period. This is done by increasing the forecast opex by an asset growth ratio.[298] This ratio is determined by dividing the value of new assets to be commissioned in a given year by the replacement cost of the existing asset base for that given year, for each year in the next regulatory control period.

Consultant review

PB considered that the methodology used to escalate maintenance effort to reflect the impact of new assets was reasonable. However, PB considered that the valuation of the replacement cost of TransGrid's existing asset base to be low.[299]

The current replacement cost of the existing asset base has been determined by using a revaluation of the optimised replacement asset base as at 30 June 2004 and making adjustments to take into account asset movements such as additions, disposals and indexation of 2.49 per cent each year (in accordance with the CPI allowed in the ACCC's 2005 revenue cap decision). The replacement valuation of the asset base as at 30 June 2007 is calculated by TransGrid to be $6.9 billion.

PB stated that new assets to be commissioned during the next regulatory control period are valued at the current construction costs and hence it is important that the value of the existing asset base be valued on the same basis. PB considered that the value of the existing asset base should reflect more recent construction costs so that the ratio is calculated using 'like for like' values. PB stated that the proposed value of $6.9 billion ($2006–07) does not necessarily reflect more recent construction costs and is too low.[300]

PB requested TransGrid to recalculate the 2006–07 replacement cost of its existing asset base by applying real escalation factors based on construction and property costs experienced since 2004 instead of just CPI.[301] The escalators applying to TransGrid's capex since 2004 are shown in table 5.9.

Applying these escalation factors to the valuation of the optimised replacement asset base, as at 2004, results in a revised replacement value of $7.8 billion ($2006–07). This represents a 14 per cent increase in the replacement value of TransGrid's existing asset base used in its revenue proposal. The application of the revised value of the 2006−07 replacement cost of TransGrid's existing asset base in the opex model reduced the forecast controllable opex by $6.1 million ($2007–08).

298 TransGrid, *Revenue proposal*, p. 86.
299 PB, pp. 222.
300 PB, pp. 222.
301 PB, pp. 222–223.

Table 5.9: Cost escalators applying to TransGrid's capex program (per cent)

	2004–05	2005–06	2006–07
Network escalation	2.81	4.95	6.15
Property escalation	4.10	4.10	4.10
CPI	2.36	2.98	2.44

Source: TransGrid response to request for information no. 150, confidential, 12 August 2008.

AER considerations

TransGrid stated that there are no rules in place for the determination of the undepreciated replacement cost of the asset base.[302] However, TransGrid noted that clause 6A.6.1(e)(3) provides that:

> …the roll forward of the regulatory asset base from the immediately preceding regulatory control period to the beginning of the first regulatory year of the subsequent regulatory control period entails the value of the first mentioned regulatory asset base being adjusted for outturn inflation, consistent with the methodology that was used in the transmission determination (if any) for the first mentioned regulatory control period for the indexation of the maximum allowed revenue during that regulatory control period.

TransGrid considered that it is reasonable and prudent to follow the guidelines set down in the NER to make annual adjustments to the undepreciated replacement cost of the asset base in a consistent manner to the roll forward of the regulatory asset base.[303]

The AER notes that the value of the current replacement cost of TransGrid's existing asset base is used to develop a ratio for determining the effect that new assets will have on maintenance effort during the next regulatory control period. It is not a proxy for the regulatory asset base value. Therefore the requirement of the NER to index the regulatory asset base by CPI is not a relevant consideration for developing the asset growth ratio.

The AER agrees with PB's view that it is important that the ratio for calculating the effect that new assets will have on maintenance costs uses 'like for like' values. The AER considers that the value of the optimised replacement asset base as at 2004 escalated for real increases in network construction and property costs provides a better proxy for the 2006–07 replacement cost of the existing asset base and therefore rejects the value of $6.9 billion proposed by TransGrid.

Accordingly, the AER will apply the value of $7.8 billion which represents the appropriate 2006–07 replacement cost of TransGrid's existing asset base escalated for real increases in network construction and property costs. This revised value will be used in the asset growth ratio which is applied in the opex model to determine the effect new assets will have on maintenance effort. The AER considers that this approach will result in opex forecasts which reflect the efficient costs a prudent

[302] TransGrid, response to request for information no. 150, confidential, 12 August 2008.
[303] TransGrid, response to request for information no. 150, confidential, 12 August 2008.

operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

Given that the asset growth ratio is determined by dividing the value of new assets by the replacement cost of the existing asset base in a given year, the revised value of the 2006−07 replacement cost of the existing asset base has the effect of reducing the asset growth ratio. Reducing the size of the asset growth ratio lowers the amount of opex required for maintaining new assets proposed to be commissioned during the next regulatory control period. This results in a reduction of $6.1 million ($2007–08) from the total forecast controllable opex.

Defect maintenance for new assets

TransGrid proposal

Defect maintenance addresses out-of-specification conditions that may affect the performance or reliability of the transmission network.[304] TransGrid has forecast defects maintenance expenditure of $152 million ($2007–08) for the next regulatory control period.[305] This represents an increase of approximately 28 per cent compared to the defect maintenance expenditure in the current regulatory control period.

To forecast defect maintenance, TransGrid relates routine maintenance costs to historical defect costs.[306] Table 5.10 shows the historical ratios over the current regulatory control period to 2006–07, the average of these ratios and the ratios by categories TransGrid has used in the opex model to forecast defect maintenance. Generally, TransGrid has used the approximate average historical defect ratios to forecast defect maintenance with the exception of the substations and land and easements categories.[307]

Table 5.10: TransGrid's actual and forecast defect maintenance ratios (per cent)

	2004–05	2005–06	2006–07	Average 2004–07	Forecast defect ratio
Lines	109	78	95	94	95
Substations	38	121	125	95	115
Communications	231	232	196	220	200
Secondary systems	49	28	29	35	30
Land and easements	732	82	48	287	40

Source: TransGrid, *Development of TransGrid opex model*, p. 15.

For the substation category a change in the allocation of costs associated with property maintenance from routine to defect has caused the significant shift from

[304] TransGrid, *Development of TransGrid opex model*, version 3 July 2008, p. 4.
[305] TransGrid, opex model, version 4.5(a).
[306] TransGrid, *Development of TransGrid opex model*, p. 15.
[307] TransGrid, *Development of TransGrid opex model*, pp. 15–16.

routine to defect maintenance. TransGrid ignored the 2004–05 year in establishing the forecast defect ratio for the substation category.[308]

In relation to the land and easements category, TransGrid is undertaking an easement transition project, which will materially change the nature of its easements related costs and will result in a substantial shift from defect to routine maintenance.[309] TransGrid has used estimates of contractor costs combined with programmed routine maintenance requirements to develop the forecast defect ratio for the next regulatory control period.

Consultant review

PB considered that the method used by TransGrid to forecast defect maintenance expenditures was sound.[310] However, PB raised an issue with the forecast defect maintenance expenditure for new assets proposed to be commissioned during the next regulatory control period.

PB considered that the growth in opex is linked to forecast growth in capital programs, as these programs result in additional new assets that require both maintenance and operating effort. However, the TransGrid opex model assumes that the amount of additional opex is directly related to the increase in new assets under management.

PB acknowledged that TransGrid has applied economy of scale factors when calculating the impact of new assets on forecast opex but that these factors relate to the ability of an existing business to integrate the management of additional assets efficiently.

PB noted that the TransGrid opex model assumes that the business is operating under a 'business as usual' scenario. PB contended that if the forecast growth in capex is the same as in the period up until the 2006–07 base year then the model outputs would be reasonable. However, the forecast growth in capex is significantly larger than that in place up until 2006−07 and PB considered that this has an impact on the reasonableness of the opex forecasts.[311]

PB stated that the majority of the new assets scheduled for commissioning during the next regulatory control period would not require any defect rectification expenditures during that period, with the exception of those identified and rectified during the warranty period. It calculated the defect rectification forecast expenditures using the opex model both with and without the asset growth escalators to determine the variation in annual forecast opex. PB recommended that the difference between these two amounts be deducted from TransGrid's forecast opex. This results in a reduction of $18 million ($2007–08) from the total forecast controllable opex.[312]

[308] TransGrid, *Development of TransGrid opex model*, p. 16.
[309] TransGrid, *Development of TransGrid opex model*, p. 16.
[310] PB, pp. 208–209.
[311] PB, pp. 223.
[312] PB, pp. 223–224.

AER considerations

TransGrid has provided further information on why it is not appropriate to assume that new assets would not require any defect maintenance expenditure.[313]

TransGrid noted that its asset base consists of a mixture of old and new assets, and that the defect ratio is based on this range in the age of assets. TransGrid stated that while it is likely that a proportion of new assets will require little in the way of defect maintenance, other new assets will require significant effort to address early life issues (particularly secondary systems). Further, TransGrid stated that there will be an increasing number of assets moving from the random failure part of the 'bathtub' curve and into an area of increasing probability of failure and therefore increasing maintenance costs.

TransGrid acknowledged that there was a significant increase in the augmentation capital works program for the next regulatory control period. However, TransGrid stated that these new assets are included in a large network of already aging assets. It modelled the impact of these new assets on the average system age and found that for most asset classes the average system age remains reasonably stable through the next regulatory control period. TransGrid stated that as the average age of assets classes is not decreasing substantially over time, the average defect ratio for the range of assets will not change substantially in the next regulatory control period. While the average age of most asset classes may not decline over time, the AER notes that it is condition rather that age that drives defect maintenance.

TransGrid provided a number of examples where new assets resulted in defect costs immediately after commissioning. For example, TransGrid referred to the cables laid in tunnels and secondary systems in the MetroGrid project. Based on PB's advice, the AER considers that the MetroGrid project is a very specific project constructed in the Sydney CBD and is not representative of the typical transmission line, cable runs and above ground oil insulated substations built in NSW. Further, secondary systems and relays comprise a small percentage of the costs of most projects and therefore any associated defects are not likely to be significant.

TransGrid also referred to the Queensland–NSW Interconnector project commissioned in 2003. TransGrid advised that the transmission lines have required $441 000 in maintenance, with the majority ($334 000) being associated with easement and access track defect work in 2003. TransGrid advised that later expenditure has been associated with routine maintenance. The AER notes that as a proportion of the total capital costs of constructing this project, the $334 000 for easement and access track defect work is a relatively small proportion of its budget.

The AER accepts that new assets may require some defect maintenance expenditure, however, based on the information provided the AER does not consider this to be significant.

The AER notes that TransGrid has developed its defect ratios largely based on historical performance of its asset base. However, TransGrid's asset base will change considerably as a result of the proposed capex program for the next regulatory control period. The average annual capex program leading up to and including 2006–07 was

[313] TransGrid, *Response to PB Draft Report*, 10 September 2008, pp. 74–77.

$176 million ($2007–08). TransGrid's proposed average annual capex program for the next regulatory control period is $525 million ($2007–08). This represents an increase of approximately 200 per cent.

Based on PB's advice, the AER considers that the defect maintenance forecast proposed by TransGrid is not reasonable because it does not factor in the significant increase in new assets proposed to be commissioned during the next regulatory control period. It agrees with the adjustment proposed by PB and will remove the defect maintenance costs for those assets which are commissioned during the next regulatory control period and will result in the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c). Following a request from the AER, TransGrid advised that this adjustment results in a reduction of $15 million ($2007–08) to the forecast controllable opex for the next regulatory control period.[314]

5.6.6 Capex/opex trade-off and productivity savings

TransGrid proposal

TransGrid has included a reduction in the forecast opex resulting from the asset replacement program proposed for the next regulatory control period. The reduction has been calculated using TransGrid's works management system.

TransGrid uses maintenance plans developed from the relevant maintenance policies to determine the maintenance scheduled tasks that are programmed into the works management system. To determine the reduction in maintenance tasks resulting from the proposed asset replacement program, TransGrid has replaced the maintenance scheduled tasks associated with the assets programmed for replacement in the works management system with the maintenance scheduled tasks for the new assets. The difference in the two work programs represents the reduction in maintenance resulting from TransGrid's proposed asset replacement program.[315]

The reduction in maintenance effort results in opex savings in both routine and defect maintenance. Table 5.11 shows the opex savings resulting from TransGrid's proposed asset replacement program.

TransGrid also incorporated economy of scale factors into its opex model. This is in recognition that new assets do not result in an incremental effort across the business equal to asset growth and that there are potential efficiencies in the management of new assets.[316]

[314] This includes adjustments for labour cost escalators and amended asset growth.
[315] TransGrid, *Development of TransGrid opex model*, p. 15.
[316] TransGrid, *Development of TransGrid opex model*, p. 13.

Table 5.11: Opex savings resulting from implementation of proposed asset replacement program ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Lines	0.3	0.5	0.2	0.7	0.7	2.4
Substations	0.2	0.2	0.0	0.1	0.4	1.0
Communications	–	–	–	–	–	–
Secondary systems	0.2	0.2	0.2	0.5	0.7	1.8
Land and easements	–	–	–	–	–	–
Total maintenance savings	0.6	1.0	0.5	1.4	1.8	5.2

Source: PB, p. 213.
Note: Totals may not add up due to rounding.

Submissions

The EMRF stated that given TransGrid's proposed increase in capex, TransGrid should be required to show:[317]

- much larger efficiency savings in the capex/opex trade-off
- larger productivity savings than the 2 per cent applied by the ACCC in the current regulatory control period and
- savings from maintenance programs no longer required on replaced assets.

Further, the EMRF stated that it would expect to see a reduction in TransGrid's forecast opex to reflect the large amount of forecast capex proposed.

The EUAA is concerned that TransGrid is proposing a real increase in its asset replacement expenditure, while also proposing a significant increase in its opex. The EUAA noted that with the proposed increase in asset replacement, TransGrid's opex could be expected to fall. The EUAA stated TransGrid has not provided information demonstrating the trade-off between asset maintenance and renewal.[318]

The EUAA also questioned whether there is a need to replace aging assets to manage increasing maintenance expenditure.[319] The EUAA noted that TransGrid sought to justify its proposed increase in both maintenance and asset replacement expenditure due to its maturing asset base and associated costs of maintaining an ageing asset base. The EUAA stated that its preliminary analysis suggested that for some asset classes the asset base is not maturing. It further submitted that there had not been any significant increase in maintenance expenditure over the last 5 years that would indicate asset age is contributing to an increase in maintenance expenditure.[320]

317 EMRF, p. 20.
318 EUAA, p. 16.
319 EUAA, p. 17.
320 EUAA, p. 17.

Norske Skog noted that TransGrid's forecast opex will increase even though a large part of its capex program is to replace old and unreliable assets. Norske Skog stated that the AER must ensure that TransGrid delivers real and measurable productivity improvements which are passed back to TransGrid's customers.[321]

Consultant review

PB considered the methodology used by TransGrid to forecast maintenance savings was robust compared to the ratio methods that are usually adopted in the absence of detailed information being available. PB concluded that the maintenance savings appeared reasonable compared to the magnitude of the proposed asset replacement program of $493 million ($2007–08).[322]

PB also considered that the economy of scale factors incorporated into TransGrid's opex model were reasonable and represent the potential efficiencies TransGrid is likely to achieve in implementing its proposed capex program.[323]

AER considerations

The AER notes that the EMRF, the EUAA and Norske Skog suggested that TransGrid should be able to show much larger savings in its opex forecasts given the replacement capex program proposed by TransGrid. Based on PB's advice, the AER is satisfied that the forecast maintenance savings are reasonable compared with the size of TransGrid's proposed asset replacement capex program.

The AER recognises that the majority of system development for the TransGrid network occurred between the 1960s and the 1980s. TransGrid advised that 40 percent of the transmission lines, 34 per cent of substations and switching stations and 25 per cent of power transformers were commissioned in the 1960s or earlier.[324] Without an asset replacement program, the AER accepts that the average age of TransGrid's assets will increase. Further, even with the proposed asset replacement program, the average age of some assets—for example, circuit breakers, reactors and capacitor banks—will increase over the next regulatory control period.[325]

Moreover, the AER considers that there are a number of other factors driving the increase in TransGrid's opex including the size of its asset base, labour cost increases and the age of assets. The AER notes that none of these factors is leading to a reduction in opex related condition requirements for TransGrid.

The AER also notes that, based on PB's advice, it has adjusted TransGrid's defect maintenance opex forecast to take into account that new assets require less in the way of defect maintenance (see section 5.6.5).

The AER does not consider it necessary to impose a specific productivity saving to TransGrid's forecast opex, as suggested by the EMRF. It notes that TransGrid has achieved efficiencies as a result of the 2 per cent productivity saving applied by the

---

321 Norske Skog, p. 5.
322 PB, pp. 212–213.
323 PB, pp. 211–213.
324 TransGrid, *Revenue proposal*, p. 34.
325 TransGrid, response to AER information request no. 178, confidential, 11 August 2008.

ACCC in the current regulatory control period. Further, a number of benchmarking reports (see section 5.6.2) suggest that TransGrid is an efficient and prudent operator.

As part of its terms of reference, PB was required to consider the efficiency of TransGrid's forecast opex for each year of the next regulatory control period and whether there exists any scope for further efficiencies. Other than the adjustments discussed in section 5.6.5, PB has not recommended other adjustments to TransGrid's controllable opex or any specific efficiency target. Further, PB noted that TransGrid's asset management process employs condition monitoring and condition based replacement triggers to maximise the life of the assets. PB concluded that TransGrid's asset management process was consistent with good industry practice.

The AER also considers that TransGrid's opex model takes into account efficiency improvements by:

- making adjustments to the 2006–07 base year for one off costs and savings achieved, before using it to project costs forward
- applying economy of scale factors that provide reductions in cost increases associated with the growth in the asset base
- providing for reductions in maintenance associated with replacement of assets with new technology.

Overall, the AER is satisfied that TransGrid has incorporated efficiencies and reasonable forecast maintenance savings in developing its forecast opex requirement for the next regulatory control period.

5.6.7 Non-controllable opex

Network support

Network support payments are payments made by service providers for demand side management of forecast constraints. Network support projects are alternatives to capital projects such as building additional transmission lines.

TransGrid proposal

The projects included in TransGrid's proposed network support payments are:[326]

- Western 500 kV conversion—This is the fourth stage in developing a 500 kV ring around the Sydney–Newcastle–Wollongong area and will convert the Bayswater – Mount Piper – Marulan leg of the ring to 500 kV. The project includes reconnection of two Bayswater power station units 3 and 4 to 500 kV and network support from embedded generation and load reduction in the Newcastle/Sydney/Wollongong area in summer 2008–09.

  This project is being carried out in conjunction with Macquarie Generation. The network support payment of $22 million in 2009–10 is to upgrade unit 3 at the Bayswater Power Station with a transformer that has a 500 kV voltage, instead of the present 330 kV.

[326] TransGrid, *Revenue proposal*, pp. 93–94.

- Reactive power capability—TransGrid proposes to enter into network support arrangements from thermal power stations for reinforcement of supply to Newcastle, Sydney and Wollongong. TransGrid has estimated that the reactive support arrangement will cost $3 million per annum ($2007–08) commencing from 2010–11. TransGrid advised that should it not be possible to arrange reactive support, it would be necessary to install shunt switched capacitor banks.

- Import capability from Snowy—TransGrid has stated that once the Uranquinty power station is commissioned there will be increased load on four lines in the south of NSW. To address the constraint, TransGrid proposed to operate a scheme that will 'trip' adequate load in NSW as required. The participants in the scheme and payments would be determined by a competitive tender process. The project that may be deferred as a result of the network support payments is the Snowy – Yass/Canberra 330 kV line upgrade. TransGrid has estimated that this network support arrangement will cost $3 million per annum ($2007–08) commencing from 2010–11.

In total, TransGrid has included $45.5 million for network support payments in the next regulatory control period.

Submissions

Norske Skog recognised the need for TransGrid to plan for network upgrades and expansion to satisfy increased demand and keep the transmission network operating at a high level of stability and reliability.[327]

However, Norske Skog stated that there are a number of events which TransGrid seeks to pass costs through to customers which effectively transfers all of the risks to customers and creates an on-going price uncertainty over the next regulatory control period. It noted that there appears to be little detail regarding the timing of individual projects, including the cost and consequences of deferment. Norkse Skog requested the AER apply the rigours of a competitive market in assessing any pass through cost applications.[328]

The EUAA also expressed a number of concerns with the pass through provisions related to network support events. In particular, the EUAA stated that customers are not provided sufficient and ongoing information to know if an event occurred that would allow a pass through of reduced costs. The EUAA also noted that pass through provisions effectively allow TNSPs to transfer risk to customers which is not matched with an ability to manage the risk, nor consistent with what would be expected from a competitive industry.[329]

Consultant review

For the Western 500 kV conversion, PB noted that this project has already commenced. TransGrid made an application to the AER on 7 December 2007 for pass through payments for network support of this project during 2008–09, which was approved by the AER on 24 January 2008.

---

327 Norske Skog, p. 3.
328 Norske Skog, p. 4.
329 EUAA, p. 32–33.

PB considered that the proposed payment for the Western 500 kV conversion has a high probability of occurring as planned, given that TransGrid has already entered into contracts to provide network support. Further, PB considered that the proposed network support payment of $22 million was consistent with the proposed capex program for 2009–10, in that the network support arrangement is made to defer capex.[330]

For the reactive power capability and import capability from the Snowy network support payments, PB noted that the estimated network support payments were approximately 10 per cent of the capital cost of the projects the network support payments sought to defer. PB concluded that the estimated values proposed by TransGrid for these network support payments were of a reasonable magnitude.[331]

PB noted that with the 2008 APR, the median commissioning date for the Bannaby – South Creek 500 kV line and substation had been deferred by one year from 2014 to 2015. PB stated that the deferral of this project may change the need for the reactive power capability network support payments, however, this is uncertain as some network support payments may still be necessary in order to provide adequate network capacity.[332]

For the import capability from the Snowy network support payments, PB noted there was little certainty around the amount, location and timing of these payments. PB stated that TransGrid plans to undertake further planning analysis next year to provide more certainty regarding the proposal.[333]

PB also noted that the NER allows for this uncertainty by providing adjustments to network support pass through events within the regulatory control period where the actual value of the network support payments differs from the forecast value allowed in the transmission determination.

PB concluded that TransGrid's proposal should be accepted on the basis that:[334]

- there is a reasonable probability that network support payments will be made
- the network support costs proposed by TransGrid are of an appropriate magnitude and
- there is a provision in the NER which allows adjustments for any under or over payments.

AER considerations

The AER notes that the Western 500 kV conversion network support costs were subject to two pass through notices which related to:

- the upgrade of the Bayswater generator transformer to 500 kV—in particular, unit 4. The AER approved a pass through amount of $31 million[335]

330 PB, p. 220.
331 PB, p. 220–221.
332 PB, p. 220.
333 PB, p. 221.
334 PB, p. 221.

- the provision of 350 MW of effective network support during the summer of 2008–09. The AER approved a pass through amount of $22 million.[336]

The AER also notes that the proposed network support payment of $22 million relates to upgrading unit 3 at the Bayswater power station with a transformer that has a 500 kV voltage and is similar to the upgrade which is planned for the unit 4 generator transformer in April 2009.

In approving the pass through notice for the upgrade of unit 4 at the Bayswater power station to 500 kV, the AER considered the following:

- based on TransGrid's demand forecasts and generation dispatch scenarios for these specific circumstances, there was a reasonable need for the pass through events during the current regulatory control period
- undertaking the network support with Macquarie Generation rather than another option was most likely the least cost option
- the steps taken by TransGrid in its negotiations with Macquarie Generation are likely to result in reasonably efficient costs in the circumstances.[337]

Given the AER's earlier assessment and that TransGrid has already entered into contracts to provide network support relating to this project, and based on PB's advice that the estimated value of the payment appears reasonable, the AER accepts the proposed network support payment to be incorporated into the forecast opex allowance for the next regulatory control period.

The AER questioned TransGrid about the need for the reactive power capability and import capability from the Snowy network support payments as a result of the revised load forecast provided under the 2008 APR.

In response, TransGrid advised that under the 2008 APR the quantity of reactive support remains, as maximum use will be made of the reactive support before undertaking other system developments. For the import capability from the Snowy network support, TransGrid advised that the 2008 APR does not change the need for improving the import capability as it is still necessary for NSW to gain access to additional southern generation following the commissioning of Uranquinty power station.[338]

While the AER is satisfied that there is a reasonable need for these two network support payments, the AER considers that that there is some uncertainty around the timing and amount of these payments. The AER notes PB's advice that the cost of network support payments cannot be estimated to the same degree of accuracy as other costs such as construction works or maintenance programs because network support services are provided by external parties on an opportunistic basis.

---

335 AER, *Statement of Reasons, TransGrid - Notice of Proposed Pass–Through for Bayswater Network Support*, January 2008.

336 AER, *Statement of Reasons, TransGrid – Notice of Proposed Pass–Through for Network Support for Deferral of the Western 500kV Conversion*, May 2008.

337 AER, *Statement of Reasons, Bayswater Network Support*, p. 2.

338 TransGrid, response to AER information request on network support payments, 3 October 2008.

The AER notes that the NER addresses this uncertainty by allowing for annual adjustments to the amount being passed through to customers, where the actual value of the network support payments differs from the forecast value allowed in the transmission determination.

The EUAA expressed concern that customers are not provided with information to know if an event has occurred that would allow a pass through of reduced costs.

Clause 6A.7.2 of the NER allows a TNSP to seek a determination from the AER for a network support pass through amount. A network support pass through is an adjustment made for network support events arising from an over or under spend in network support payments that were provided for in a transmission determination. There is no materiality threshold for network support events under chapter 6A, thereby ensuring that all under and over recoveries of network support payments are subject to the pass through provisions.

If a positive (defined as an overspent amount) or negative (defined as an underspent amount) network support event occurs during a regulatory control period, a TNSP must seek a determination by the AER for a network support pass through amount to customers. For a positive network support event one of the factors the AER must take into account is the efficiency of the TNSP's decision and actions in relation to the risk of the event, including whether the TNSP:

- has failed to take any action that could reasonably be taken to reduce the magnitude of the positive network support event and
- has taken or omitted to take any action where such action or omission has increased the magnitude of the amount in respect of that event.[339]

Regardless of whether the AER is notified by a TNSP, the AER may make a determination to pass through any underspent amount to consumers.[340] However, the AER would expect TransGrid to notify it of any underspent amounts relating to its network support allowance, to ensure that these amounts are passed back to customers.

Given the network support pass through provisions in the NER the AER is satisfied that the network support payments are a reasonable estimate of the costs for the network support events proposed by TransGrid and therefore accepts the forecasts.

Self insurance

TransGrid proposal

TransGrid provided a board resolution to self insure for the following events:[341]

- losses for which insurance is commercially unavailable, uneconomic or excluded under a policy of insurance (e.g. transmission lines)
- workers compensation costs below the determined threshold (currently $750 000)[342]

339 NER, clause 6A.7.2(i)(3).
340 NER, clause 6A.7.2(f).
341 TransGrid, *Revenue proposal*, appendix M.

- losses for insured risks below the existing insurance policy deductibles.

SAHA International Limited (SAHA)[343] was engaged by TransGrid to provide a report regarding the management of these, and other risks.[344] The report forms the basis for the quantification of the proposed self insurance allowance included in TransGrid's forecast operating expenditure for the next regulatory control period. Table 5.12 sets out the risks which SAHA proposed TransGrid self insure for and the total premium for each risk over the next regulatory control period.

Table 5.12: TransGrid's proposed self insurance risk premium for the next regulatory control period ($m, 2007–08)

Type of risk	Risk premium	Updated risk premium
Fraud	0.07	0.07
Environmental contamination	1.00	2.50
Bomb threat/hoax, terrorism	0.12	0.12
Earthquakes (magnitude of less than 7)	0.62	0.83
Insurers' credit	0.03	0.03
Counterparty credit	0.05	0.05
Bushfire	0.46	1.34
Risk of non-terrorist impact of planes and helicopters	0.45	0.64
Towers and lines	3.35	6.55
Key assets (transformers and circuit breakers)	3.04	3.36
Key person risk	0.16	0.16
Contractual risks	0.06	0.06
General public liability	0.06	0.06
Failure to supply	0.10	0.10
Total self insurance risk premium	9.54	15.84

Source: SAHA, *Self Insurance Risk Quantification – Overview of Results*, 21 May 2008; and SAHA, *Self Insurance Risk Supplementary Report – Response to AER/PB*, 5 August 2008.
Note: Totals may not add up due to rounding.

TransGrid initially proposed a self insurance allowance of $9.5 million ($2007–08) for the next regulatory control period. In response to issues raised by PB and the AER in reviewing TransGrid's proposed allowance for self insurance, TransGrid provided a supplementary report from SAHA.[345] The supplementary SAHA report recalculated the self insurance premiums based on updated information for a number of risks. Those risks which have updated self insurance premiums are also outlined in table 5.12. Taking into account the updated self insurance premiums, TransGrid's

342 Workers compensation is included in the base year in the opex model and is not included in the self insurance premium proposed by TransGrid.
343 SAHA provides strategic, commercial, economic, corporate finance and financial consulting services. See SAHA website <http://www.sahainternational.com/SAHA/SERVICES/pc=PC_90006>.
344 TransGrid, *Revenue proposal*, appendix L.
345 SAHA, *Self insurance risk supplementary report – response to AER/PB*, 5 August 2008.

proposed self insurance allowance is $15.8 million for the next regulatory control period.[346]

Consultant review

PB undertook a review of TransGrid's updated self insurance allowance. PB considered that the annual risk premiums for the nominated risks (with the exception of one) were reasonable estimates of the cost of self insurance. PB recommended an adjustment to the self insurance premium for the impact of a non-terrorist helicopter or plane on a transmission asset. PB concluded that a self insurance allowance of $16 million for TransGrid was reasonable.[347]

AER considerations

Details of the AER's assessment of TransGrid's proposed self insurance allowance are provided at appendix E.

In summary, the AER is satisfied that TransGrid's proposed allowances for self insurance for the following risks reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives:

- fraud risk
- insurers' credit risk
- counterparty credit risk
- risk of non-terrorist impact of planes and helicopters.

However, for other risks the AER is not satisfied that SAHA has provided robust analysis which supports the probability of certain events occurring or that the costs of those events are reasonable. Accordingly it has not accepted the calculation of the self insurance premiums.

The AER is not satisfied that TransGrid's proposed self insurance allowance reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

As a result of its analysis of the information provided the AER is satisfied that the revised estimate of self insurance costs set out in table 5.13, based on the accepted self insurance premiums detailed in appendix E, reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

[346] TransGrid, response to information request no 156, 5 August 2008.
[347] PB, pp. 214–219.

Table 5.13: AER's conclusion on self insurance allowance for the next regulatory control period ($m, 2007−08)

	TransGrid's proposal	AER's adjustments	AER's conclusions
Total self insurance risk premium	15.8	–9.1	6.8

Note: Totals may not add up due to rounding

Debt raising costs

To raise debt, a company has to pay debt financing costs or transaction costs over and above the debt risk premium. Such costs are likely to vary between each debt issue and depend on market conditions.

According to the Allen Consulting Group (ACG) the debt raising cost being considered should be the transaction cost of re-financing fixed rate bonds to the value of the notional gearing component of the regulated firm's RAB. The allowed debt benchmark does not relate to:

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

Therefore, the transaction costs associated with the benchmark cost of debt should not relate to activities outside of the re-financing of bonds for the regulated firm's core activities.[348]

TransGrid proposal

TransGrid engaged CEG to advise it on appropriate costs of raising debt.[349] CEG recommended that the cost of raising debt be set by reference to both direct and indirect costs:

- direct costs—the direct fees charged by the underwriter, credit rating agency and so on
- indirect costs—the cost of issuing capital at a discount in the market to sell it (underpricing).

CEG considered that it is incorrect to estimate capital raising costs based on direct costs without including an estimate for indirect costs.

CEG noted that the yield to maturity on debt issued by private placement is at least 19 basis points higher than debt issued by public placement. CEG considered that it is a form of cherry-picking for the AER to set interest rates based on debt issued publicly and to restrict debt raising cost estimates to evidence of direct costs in private placement markets by ignoring the higher indirect costs of raising debt in this manner.

CEG recommended that the unit cost of raising debt be set at least equal to 15.5 basis points per annum (bppa) of the amount of debt to be raised.[350] Of this unit cost of

[348] ACG, *Debt and equity raising transaction costs: final report to the ACCC*, December 2004, p. 5.
[349] TransGrid, *Revenue proposal,* Appendix O.

15.5 bppa, 3.0 bppa is included for indirect costs and the remainder represents the direct costs. TransGrid has proposed a debt raising cost allowance of $22 million ($2007–08) for the next regulatory control period.[351]

AER considerations

The AER uses private debt raising (issuance) costs as a proxy to set an allowance for public debt issuance costs because these costs are not observable in the Australian market. The AER considers that private placement underwriting costs, which forms part of debt issuance costs, are a reasonable proxy for public issuance underwriting costs. This position is supported by the CEG report where it stated 'Livingston and Zhou (2002) find underwriter fees for private placements are not significantly different to public placements'.[352] ACG in its 2004 report for the ACCC also argued that private underwriting costs are a fair proxy for public debt underwriting costs on the basis of the 2002 Livingston and Zhou study.[353]

Overall, the AER is using a publicly available estimate of the debt risk premium on the chosen benchmark firm combined with a publicly available estimate of the debt issuance costs on this benchmark firm. The AER considers these estimates for the debt risk premium and debt issuance costs are the best estimates of the cost of raising public debt currently available. As such, the AER considers that there is no inconsistency or under compensation to firms from using this approach.

CEG's proposed use of the yield from private debt is inconsistent with the efficient benchmark regulated firm that is assumed to be able to issue BBB+ public corporate debt to raise its debt capital.

The AER applies the benchmark BBB+ credit rating with 60:40 debt to equity ratio as specified in clause 6A.6.2 of the NER. It is implicit in the use of this benchmark that the firm can issue public corporate debt in the market at a BBB+ rating and at the average yield to maturity associated with BBB+ public bonds. If firms effectively issue at a higher yield than BBB+, for example due to underpricing the debt, the firms are effectively issuing higher yielding lower grade debt. The proposed underpricing premium is therefore inconsistent with the assumed BBB+ benchmark.

CEG also argued that it is reasonable to assume BBB debt will be more underpriced than the average investment grade debt. CEG has, however, not provided any supporting evidence that BBB+ or even BBB debt is on average issued at a discount (underpriced).

In support of its proposed debt issuance allowance, CEG cited a working paper by Saunder, Palia and Kim (2003) that looked at debt issues in the United States over the period from 1970 to 2000.[354] However, the AER does not consider that this working paper supports the argument that Australian regulated firms are under compensated for the following reasons:

---

350 TransGrid, *Revenue proposal*, p. 92.
351 TransGrid, *Revenue proposal*, p. 96.
352 TransGrid, *Revenue proposal,* Appendix O, p. 18.
353 ACG, 2004, p. 19.
354 TransGrid, *Revenue proposal,* Appendix O, pp. 13, 17.

- there is no evidence that the average debt issuance costs of the average US public debt issue is representative of the debt issuance costs of a stable regulated business in Australia. This is even more clearly the case with all regulated firms excluded from the sample used

- the working paper indicates that the lowest fifth percentile of firms pay a fraction of the debt issuance costs of the average firm. Using a mean estimate of firms across an economy to estimate debt issuance costs for regulated firms does not appear to be reasonable, given regulated firms should have among the lowest costs of raising debt due to their stable, regulated cash flows. It is also inconsistent with the benchmark used to set the costs of debt generally discussed above.

The current approach of the AER to use private debt issuance costs for Australian companies accessing the private debt markets is therefore considered to provide a better estimate of public debt issuance costs of Australian firms than the study CEG cited by Saunders, Palia and Kim. While the AER acknowledges it has used a proxy for debt issuance costs of public issues, the use of this proxy is more consistent with the assumptions associated with the use of an efficient benchmark regulated firm than the use of figures from the Saunders et al study.

On the basis of the information put forward, the AER is not satisfied that there is a need to provide indirect debt raising costs under the benchmark regulatory framework, or that the current method used to calculate these costs is under compensating regulated firms. The AER therefore considers that the indirect debt raising costs do not reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c). Accordingly, the AER will maintain its current approach of providing benchmark debt raising costs in accordance with the ACG methodology as applied in previous revenue determinations.[355]

Under this methodology, the ACG based its benchmark on debt raising costs applicable to Australian international bond issues and joint Australian market/international issues and found that the benchmark decreases as the number of bond issues increase.

In developing the benchmark, the ACG calculated a gross underwriting fee benchmark of 5.5 bppa based on a 5-year term. To this, it added allowances for legal and roadshow expenses; credit rating fees for the firm and for each issue of bonds; and registry and paying charges. The median bond issue size was determined to be $175 million.

In accordance with the ACG methodology, the AER updated the gross underwriting fee and bond issue size benchmarks using recent publicly available data. This resulted in the gross underwriting fee increasing from 5.5 bppa to 6.0 bppa and the median bond issue size increasing from $175 million to $200 million.[356]

[355] ACG, 2004, pp. 8–13.

[356] The latest update by the AER indicates that the gross underwriting fee remains at 6.0 bbpa and the median bond issue size remains at $200 million.

Table 5.14 shows the updated build up of debt raising costs and the total benchmark for various bond issues, based on the ACG's methodology.

TransGrid has an opening RAB of $4234 million and an assumed benchmark gearing ratio of 60:40. The notional debt component of TransGrid's opening RAB is therefore around $2540 million. Based on the ACG methodology which assumes refinancing of debt with each regulatory determination, this debt size would require around 13 bond issues. As such, the AER considers that an allowance of 8.1 bppa for debt raising costs is a reasonable benchmark for TransGrid. Using the post-tax revenue model (PTRM), this benchmark is multiplied by the debt component of TransGrid's opening RAB to provide an average allowance of $2.2 million per annum ($2007–08).

Table 5.15 shows the AER's conclusion on the debt raising cost allowance for TransGrid.

Table 5.14: Benchmark debt raising costs for corporate bond issues (bppa)

Fee	Explanation/source	1 issue	2 issues	6 issues	13 issues
Amount raised	Multiples of median bond issue size	$200m	$400m	$1200m	$2600m
Gross underwriting fees	Bloomberg for Australian internal issues, term adjusted	6.0	6.0	6.0	6.0
Legal and roadshow	$75k–$100k: industry sources	1.0	1.0	1.0	1.0
Company credit rating	$30k–$50k (once off): S&P ratings	2.5	1.3	0.4	0.2
Issue credit rating	3.5 (2.5) basis points up front: S&P ratings	0.7	0.7	0.7	0.7
Registry fees	$3k/issue: Osborne Associates	0.2	0.2	0.2	0.2
Paying fees[a]	$1/$1m quarterly: Osborne Associates	0.0	0.0	0.0	0.0
Total	Basis points per annum	10.4	9.2	8.3	8.1

Source: AER updated figures based on the methodology in ACG, *Debt and equity raising transaction costs: final report to the ACCC*, December 2004.
(a) Rounded to one decimal place.

Table 5.15: AER's conclusion on debt raising costs ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Debt raising allowance	1.9	2.1	2.2	2.4	2.6	11.2

The AER considers this revised benchmark debt raising forecast represents the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives in the next regulatory control period.

Equity raising costs—forecast capital expenditure

An entity incurs equity raising costs when it raises new equity capital. These costs may include legal and brokerage fees, and marketing costs. For initial equity raising costs, the fundamental question is whether the RAB has already been determined. The need for access to external equity funds would generally not be expected if the entity were financed in a manner consistent with regulatory benchmark assumptions.

According to the 2004 ACG report, firms finance subsequent capex in the least-cost manner. That is, financing is sourced from retained earnings when possible and that debt financing is preferred to equity financing (this relates to the 'pecking order theory' of capital structure).[357] External equity financing for subsequent capex should be considered only when a case is made that the retained earnings and additional borrowings are insufficient provided that the gearing ratio and other assumptions about financing decisions are consistent with regulatory benchmarks.

TransGrid proposal

TransGrid noted that the main area of contention over the appropriate methodology for estimating the amount of equity that must be raised relates to the assumption of how much equity should be raised through retained earnings and how much externally. TransGrid stated that ACG has provided evidence from listed Australian businesses to suggest that a benchmark regulated utility would optimally maintain a dividend yield of 8.6 per cent even if it were raising significant equity capital. TransGrid proposed to adopt ACG's advice in estimating the amount of equity capital to be raised.[358]

Similar to the cost of raising debt, CEG considered that equity raising costs must capture both direct and indirect costs of raising equity. CEG argued that the AER's base equity issuance costs on advice from ACG only estimates the direct costs of raising equity. TransGrid stated that CEG concluded 'the current 3 per cent allowance for seasoned equity issues is too low given the substantial evidence of underpricing in the academic literature'.[359]

CEG recommended that the unit cost of raising equity be set at 7.6 per cent of the amount of equity to be raised. TransGrid has proposed an equity raising cost allowance of $14 million ($2007–08) for the next regulatory control period.[360]

AER considerations

To establish a benchmark allowance for equity raising costs based on the methodology recommended by ACG, two questions need to be answered. First, how much new equity is required to fund forecast capex, and second, what is the benchmark unit cost as a percentage that is to be applied to the equity requirement.[361]

---

357 ACG, 2004, pp. ix–xii.
358 TransGrid, *Revenue proposal*, pp. 91–92.
359 TransGrid, *Revenue proposal,* Appendix O, p. 22.
360 TransGrid, *Revenue proposal*, p. 96.
361 ACG's 2004 report to the ACCC outlined when additional benchmark equity raising may be required, while its report on behalf of Powerlink in 2007 outlined a cash flow analysis method to determine exactly how much benchmark equity raising would be required over the regulatory control period.

Issues underpinning the answers to these questions are discussed in turn below commencing with consideration of indirect equity raising costs.

Indirect cost of raising equity

The AER accepts that underpricing can occur for both initial public offerings and seasoned equity offerings. However the AER does not agree with CEG's proposal that this underpricing or indirect costs need to be included in the benchmark equity raising (issuance) costs allowed in a revenue determination. Even if underpricing for equity raising does occur, the AER considers that:

- no compensation is required for such costs because it would be inconsistent with the benchmark regulatory framework applied to determine the weighted average cost of capital (WACC)
- the efficient benchmark network service provider should be able to raise capital without incurring underpricing costs.

It is assumed by the AER that in setting a benchmark allowance for equity raising costs it is regulating a hypothetical efficient benchmark firm. The efficient benchmark firm should be a large listed firm and while firms may operate under different structures to this, compensation should not be provided for any deviation from the benchmark.

The efficient benchmark firm should be able to raise new capital with a seasoned equity offering.[362] Where a firm can undertake a seasoned equity offering, it can use a rights issue where the firm offer shares at a discount to its existing shareholders. This is the most common practice for seasoned equity offerings. In a rights issue, even though the shares are offered at a discount, the firm's existing shareholders benefit from the entire discount and there should be no wealth transfer to new shareholders or loss by existing shareholders. If the existing shareholders do not wish to further invest in the firm they can usually sell their rights (as rights are normally tradable/renounceable and the issuing firm has the option of making them renounceable), or alternatively they can sell some of their existing shares to given them the funds to take up the rights. When viewed in this context, there should be no loss to the firm or its existing shareholders and therefore no requirement to compensate the firm for underpricing.

The efficient benchmark firm is also assumed to be able to raise capital by offering a given return (the awarded WACC). This rate of return implicitly includes compensation for all systematic risk. Therefore, the efficient benchmark firm already includes full compensation for all investor risk that requires compensation under the CAPM and an underpricing allowance—an extra form of compensation for risk for new investors—is not required. The allowed WACC is already determined to be sufficient to induce new investment, and further compensation is unnecessary and inconsistent with the assumptions of the benchmark regulatory framework, and the use of the capital asset pricing model (CAPM). Importantly, the CAPM (a

[362] In relation to Government owned businesses, the guiding principle is that they should be treated the same under competitive neutrality and therefore assumed to be an efficient listed private enterprise that can raise equity through seasoned equity offerings.

requirement of the NER) assumes all investors have the same required return. This also implies that there should be no allowance for underpricing for new investment.

Finally, CEG has also implicitly argued that as underwriting and underpricing are substitutes, the expected underpricing 'cost' should be paid. This is based on the argument that greater (lesser) underpricing leads to lower (greater) underwriting fees. In relation to this the AER considers that, for traditional underwriting, where the underwriter effectively sells a put option to the issuing firm over some or all of the issue, there is likely to be an inverse relationship between the level of underpricing and the underwriting fee. This is because the lower the strike price on the underwriting option, the lower the probability that the underwriter will incur losses associated with the exercise of the option and therefore the resulting underwriting fee charged.

However, having reviewed equity issuance allowances the AER considers that there are actually strong arguments that the option component of the underwriting fee should not be paid. This is because the underwritten firm should expect to get a payoff with a present value equal to the fair value of the option. Therefore, if anything, CEG's argument appears to support the proposition that the current estimate of direct equity issuance costs should be reduced by the fair value of the option component of the underwriting fee. However, the magnitude of such an adjustment, if required, is yet to be resolved. These matters are the subject of further analysis and investigation by the AER.

Accordingly, the AER has not adjusted the current cost of seasoned equity offering allowances downwards to account for the option component of the underwriting fee in this draft decision.

Based on the information submitted, the AER is not satisfied that there is a need to take account of the indirect unit cost of raising equity under the benchmark regulatory framework. The AER notes that in its recent transmission price control review, the Office of Gas and Electricity Markets (UK regulator) considered a proposal for an allowance for indirect equity issuance costs. The UK regulator rejected the proposed allowance.[363] Accordingly, the AER will maintain its current approach of using the direct unit cost of raising equity to determine a benchmark equity raising cost allowance when a case for external equity financing associated with forecast capex has been established.

Equity raising requirement—cash flow analysis

The AER has reviewed ACG's analysis of TransGrid's benchmark cash flows to establish the requirement for equity raising costs associated with the equity component of its forecast capex over the next regulatory control period. The methodology applied to determine benchmark equity raising costs is summarised by the following steps:

- revenues less expenses (including opex, interest payments and tax) provides the internal cash flow

[363] Office of Gas and Electricity Markets, *Transmission price control review: Final proposals*, 4 December 2006, p. 59.

- internal cash flow less dividends to shareholders provides the retained cash flow
- retained cash flow is used to fund the equity component of capex
- unused retained cash flow, consistent with the pecking order theory, is carried over to the following year to fund the equity component of capex
- equity component of capex less retained earnings (where it is insufficient) indicates the additional equity required
- equity raising cost is then calculated by multiplying the additional equity required with the assumed benchmark transaction cost for subsequent equity issues.

This cash flow approach to determining an allowance for equity raising costs was considered by the AER in its recent ElectraNet and Powerlink transmission determinations to be reasonable and consistent with the principles of benchmark financing arrangements, subject to some adjustments.[364] Similar adjustments are required to TransGrid's proposed cash flow modelling. These are:

- 'depreciation' should be referenced to nominal straight-line depreciation (as specified in row 322 of the 'assets' sheet of the PTRM).
- 'interest payment' should be directly referenced to row 52 of the 'analysis' sheet of the PTRM which is labelled 'interest payments'.

Further, the AER accepts TransGrid's proposal to use 'smoothed' revenue rather than 'unsmoothed' revenue (which is based on the timing of costs) in the cash flow analysis as this reflects the expected revenues that TransGrid will receive.

The main issue in contention with the cash flow analysis is the assumed amount of dividend payments. The AER has previously assumed a dividend yield of 3.5 per cent, which was based on the average dividend yield of a sample group of Australian companies that were expecting to undertake large capital expenditure programs.[365] In its report prepared for TransGrid, ACG has argued that the AER's assumed dividend yield is inappropriate for the following reasons:[366]

- the AER's sample companies did not have the normal characteristics of regulated utilities, instead having lower gearing levels, lower dividend yields and lower dividend payout ratios
- regulated utilities do not reduce dividends with the purpose of funding capex as they develop an investor clientele with a preference for high dividends. This also has implications for the extent to which dividend reinvestment plans can mitigate the requirement to raise equity.

---

364 AER, *Decision – Powerlink revenue cap*, pp. 99–102;
AER, *Final decision – ElectraNet transmission determination*, pp. 85–89.

365 The AER's cash flow analysis has used the RAB value as a proxy for the market value to apply the dividend yield assumption. See AER, *Powerlink*, pp. 99–102.

366 ACG, *Transaction costs of raising equity finance: the dividend yield assumption*, 9 May 2008, pp. iv–v.

ACG advocated a dividend yield of 8.6 per cent, based on the average of 'high yield' utilities calculated by UBS in September 2007.

The AER acknowledges that the sample of firms used to develop a benchmark dividend yield assumption for a TNSP undertaking substantial capex includes companies that in many ways are dissimilar to regulated businesses. However, when it was assessing this issue during the Powerlink revenue reset process, the purpose of the sample companies was specifically to derive a benchmark dividend yield for a firm planning to undertake major capital works. The sample firms shared this key characteristic with Powerlink. The AER notes that the sample firms would ideally include only domestic regulated entities with many similar characteristics to TNSPs, however, such comparators and data were not available.

The AER has reflected on the use of the dividend yield in the cash flow analysis and notes the following weaknesses with making assumptions about the dividend yield:

- There is a lack of directly comparable firms from which to develop an average dividend yield. While the firms included in the UBS high yield utilities may bear similar characteristics to regulated TNSPs, it is not clear that they are all planning large capital works beyond normal expenditure levels.

- Some of the sample firms in the UBS high yield utilities employ trust business structures which are inconsistent with the benchmark company structure assumed for regulatory purposes. These trust structured firms may have different dividend policies due to their legal structure.

- Dividend payments are made infrequently, generally only twice per annum. The dividend yield assumption is dependent on the market value of the company's equity. For publicly listed firms, this is taken to mean the share price. As the market value of equity may be volatile, reported dividend yields vary from day to day and are beyond the control of a company's management. Furthermore, dividend yields tend to be reported as the most recent 12 months of dividend payments divided by the current share price. These factors may make benchmarked dividend yields an unreliable way to forecast efficient forward looking dividend payments by regulated firms.

It should also be noted that when ACG's recommended dividend yield assumption is applied to the cash flow analysis using the correct depreciation measure[367], the resultant payout ratio is unsustainable at well over 100 per cent of net profit after tax. This is clearly an unreasonable set of assumptions. Against this however, the AER acknowledges that ACG considered a dividend yield of 3.5 per cent to be inconsistent with the assumed gamma of 0.5, which is specified in the NER.[368]

The AER considers that these problems with the use of the dividend yield outlined above can be overcome by altering the assumptions in the cash flow analysis. Specifically, it is possible to make an assumption with respect to the dividend payout ratio rather than the dividend yield. The dividend payout ratio is the result of an

[367] The correct depreciation measure is nominal straight-line depreciation as specified in the 'assets' sheet of the PTRM.

[368] TransGrid, *Revenue proposal,* Appendix O, p. 26

explicit management decision rather than a potentially volatile market measure. It is also a more direct method to establish the amount of retained earnings available for investment and therefore the remaining amount required to be raised as equity. The assumption on the appropriate dividend payout ratio can be made so that the dividend payout ratio is consistent with the gamma value required by the NER.

One could argue that investors expect stable returns in the form of dividends and for that reason management choose an absolute dividend value rather than a portion of profits. Such a strategy could be used to smooth over fluctuations in profit from year to year. However, regulated TNSPs typically earn very stable revenues which mitigate year to year fluctuations that may be observed by the broader market. In other words, there is likely to be little difference in the dividends of a regulated TNSP between specifying the dividend amount and specifying the dividend payout ratio.

Accordingly, the AER has decided to amend the cash flow analysis to rely on the assumption of a given dividend payout ratio rather than a given dividend yield. Clause 6A.6.4(a) of the NER deems the assumed utilisation of imputation credits to be 0.5. The AER understands that this value specified in the NER arises from previous analysis and observations of the ACCC.[369] The analysis of the ACCC included an assumption about the appropriate dividend payout ratio in drawing a conclusion on the value to be assumed for gamma or the utilisation of imputation credits. In this regard, the AER considers that a 70 per cent payout ratio is consistent with clause 6A.6.4(a) of the NER. Further, such a payout ratio is consistent with sound management of the benchmark TNSP as a going concern—as opposed to implicitly applying a dividend payout ratio in excess of 100 per cent of earnings.[370]

Based on the capex allowance in this draft decision, the benchmark cash flow analysis indicates that TransGrid would be able to fund its capex program over the next regulatory control period with retained cash flows and therefore does not require additional equity finance, as shown in table 5.16. The AER does not consider TransGrid's proposed equity raising costs represent the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6. Accordingly, the AER will not provide TransGrid an allowance for equity raising costs for the next regulatory control period.

[369] This observation was made in the ACCC's 2004 draft decision for TransGrid, which informed the ACCC's view that the assumed utilisation of imputation credits be 0.5 in the 2004 Statement of Regulatory Principles (SRP). It is also supported by a more recent estimate of the franking credit payout ratio—see Hathaway and Officer, *The value of imputation tax credits – update 2004*, Capital Research Pty Ltd, November 2004. Matters relating to the assumed utilisation of imputation credits are currently under consideration in the context of the AER's WACC review to be finalised in March 2009.

[370] As noted, this is the outcome of assuming an 8.6 per cent dividend yield with corrected cash flow analysis that uses the correct measure of depreciation.

Table 5.16: Benchmark capex funding requirement ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Capital expenditure funding	564.3	480.9	610.2	588.6	441.9	2686.1
Debt funding component	338.6	288.6	366.1	353.2	265.1	1611.6
Equity funding component	225.7	192.4	244.1	235.5	176.8	1074.4
Less: retained cash flows	200.3	216.9	225.4	243.3	264.4	1150.4
Additional equity requirement	25.4	–24.5	18.7	–7.8	–87.7	–76.0

Note: Negative sign for the additional equity requirement row indicates that there are sufficient retained cash flows to finance the equity component of capex.

5.7 AER conclusion

The AER has considered TransGrid's forecast total opex of $849 million ($2007–08) and for the reasons outlined in this chapter is not satisfied that this total opex forecast proposed by TransGrid reasonably reflects the opex criteria under clause 6A.6.6(c):

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

In drawing this conclusion the AER has had regard to the opex factors set out in clause 6A.6.6(e) of the NER.

As the AER is not satisfied that TransGrid's total forecast opex reasonably reflects the opex criteria, under clause 6A.6.6(d), the AER must not accept the forecast opex in TransGrid's revenue proposal. Therefore, the AER is required under clause 6A.14.1(3)(ii) to provide an estimate of the total opex that TransGrid will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

On the basis of its analysis of TransGrid's proposed opex forecast and the advice of PB, the AER has applied a reduction of $90 million to TransGrid's proposed opex. This represents a reduction of around 11 per cent of TransGrid's proposed opex of $855 million and results in an amended forecast opex allowance of $765 million.[371]

This allowance represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives. The AER is satisfied that the total forecast opex of $765 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. This is shown by opex category in table 5.17.

[371] The forecast opex allowance is $805 million in 2008–09 dollar terms.

Table 5.18 sets out the AER's adjustments to TransGrid's forecast controllable opex allowance. These adjustments are derived from the opex model, and represent the consolidated impact of all the modelling corrections agreed by TransGrid and further adjustments reflecting the AER's conclusion on an efficient controllable opex allowance.

Table 5.17: AER's conclusion on TransGrid's total opex allowance ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's proposed controllable opex	135.2	144.4	149.7	161.8	166.5	757.6
Debt raising costs	3.7	4.0	4.3	4.8	5.1	22.0
Equity raising costs	0.9	1.7	3.1	4.0	4.2	13.9
Network support costs	21.5	6.0	6.0	6.0	6.0	45.5
Self insurance costs[a]	3.2	3.2	3.2	3.2	3.2	15.9
TransGrid's total opex	164.5	159.2	166.3	179.8	185.0	854.8
AER's controllable opex	128.4	135.7	139.5	147.9	149.9	701.3
Debt raising costs	1.9	2.1	2.2	2.4	2.6	11.2
Equity raising costs	–	–	–	–	–	–
Network support costs	21.5	6.0	6.0	6.0	6.0	45.5
Self insurance costs	1.4	1.4	1.4	1.4	1.4	6.8
AER's total opex allowance	153.2	145.1	149.0	157.6	159.8	764.8

Note: Totals may not add up due to rounding.
The AER will update the opex model with the latest CPI data at a time closer to its final decision.
(a) TransGrid submitted an updated self insurance proposal on 5 August 2008.

Table 5.18: AER's adjustment to TransGrid's controllable opex ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
TransGrid's proposed controllable opex	135.2	144.4	149.7	161.8	166.5	757.6
Agreed updated forecast opex	131.5	140.6	144.9	156.5	161.5	735.1
Adjustment for labour escalator	–2.6	–1.3	–1.1	–2.0	–4.0	–11.0
Adjustment for revised capex forecast	–0.2	–0.1	–0.0	–0.9	–0.3	–1.3
Adjustment for asset growth and defects	–0.3	–3.7	–4.4	–5.8	–7.4	–21.5
AER's adjusted controllable opex	128.4	135.7	139.5	147.9	149.9	701.3

Note: Totals may not add up due to rounding.

6 Efficiency benefit sharing

6.1 Introduction

This chapter sets out the AER's assessment of efficiency savings accruing to TransGrid under the efficiency carry forward mechanism (ECFM), which applies to its opex allowance for the current regulatory control period. It also sets out how the efficiency benefit sharing scheme (EBSS) is to apply to TransGrid for the next regulatory control period.

The ECFM provides TNSPs with more consistent efficiency incentives by allowing them to retain the benefit of any savings (or exposing them to the detriment of any losses) for the same length of time regardless of when in the regulatory control period the gains/losses are made. During the next regulatory control period TransGrid will receive benefits/penalties for efficiency gains/losses made during the current regulatory control period in accordance with the ECFM.

The EBBS has evolved from the ECFM and operates in a similar manner. The AER published the EBSS under clause 6A.6.5(a) of the NER, which establishes that an EBSS will apply to TransGrid from 1 July 2009.[372] The scheme will not have a direct financial impact on TransGrid until the 2014–19 regulatory control period, when it will receive carryover benefits/penalties for efficiency gains/losses made during the next regulatory control period.

6.2 Regulatory requirements

Clause 11.6.10 of the NER provides for adjustments to the maximum allowed revenue (MAR) arising from any carryover mechanisms implemented as part of the previous revenue determination and other arrangements agreed between the AER and the TNSP.

The ACCC's 2005 revenue cap decision for TransGrid[373] provided that the ECFM set out in the ACCC's 2004 *Statement of principles for the regulation of electricity transmission revenues* (SRP) will apply to TransGrid for the current regulatory control period. The decision provided that any change to the opex allowance that results from a pass-through or any re-opening of the revenue cap will not affect the calculation of the ECFM.

Clause 6A.6.5(a) of the NER requires the AER to develop and publish an EBSS. An EBSS shares between TNSPs and transmission network users the efficiency gains or losses derived from the difference between a TNSP's actual opex and the forecast opex for a regulatory control period.

Both the ECFM and the EBSS carryover efficiency gains/losses for five years after the year in which the efficiency gain/loss is made. The calculation of efficiency gains/losses under the ECFM and EBSS is outlined below.

---

372 AER, *Electricity transmission network service providers – Efficiency benefit sharing scheme*, September 2007.

373 ACCC, *TransGrid Final Decision*, p. 51.

First year formula

Under both the ECFM and EBSS an efficiency gain or loss in the first year of the regulatory control period is calculated using the following formula:

$$E_1 = F_1 - A_1$$

where:

E_1 = the efficiency gain/loss in year 1

A_1 = the actual opex incurred by the TNSP for year 1 of the regulatory control period

F_1 = the forecast opex accepted or substituted by the AER for that year in the transmission determination for year 1 of the regulatory control period.

Subsequent years' formula

Under both the ECFM and EBSS, gains or losses that arise in the second and subsequent years of the regulatory control period will be calculated as:

$$E_t = (F_t - A_t) - (F_{t-1} - A_{t-1})$$

where:

E_t = the efficiency benefit/loss in year t

A_t, A_{t-1} = the actual, or adjusted actual, opex incurred in years t and t–1 respectively

F_t, F_{t-1} = the forecast, or adjusted forecast, opex accepted or substituted by the AER for the years t and t–1 respectively.

Final year formula

The transmission determination for the next regulatory control period will be made by the AER prior to the completion of the current regulatory control period. For the purposes of the ECFM the AER will assume that actual opex in the fifth year of the current regulatory control period will be equal to TransGrid's best forecast at the time of submitting its revenue proposal.

An error correction mechanism will then be applied at the revenue reset for the 2014–19 regulatory control period to account for any difference between actual opex and TransGrid's forecast opex for the fifth year of the current regulatory control period.

Similarly, the transmission determination for the 2014–19 regulatory control period will be made prior to the completion of the next regulatory control period, however, the approach for dealing with this issue is different under the EBSS. For the purposes of the EBSS the AER will estimate the actual opex (A_5) required to calculate gains or losses for the final year of the next regulatory control period as follows:

$$A_5 = F_5 – (F_4 – A_4)$$

Where differences arise between this estimate and the actual opex of the final year of the next regulatory control period, the efficiency gain or loss in the first year of the 2014–19 regulatory control period (E_6) will be adjusted as follows:

$$E_6 = (F_6 – A_6) – (F_5 – A_5) + (F_4 – A_4).$$

Other provisions

The SRP also notes that the:

> …efficiency carry forward calculation will be undertaken in such a way as to ensure inflation does not erode the value of any benefit/loss to be retained by the TNSP.[374]

A similar provision is included in the EBSS.[375] The EBSS also makes provision for:

- adjustments to forecast opex allowances to account for variations between forecast and outturn demand growth[376]
- TNSPs to propose cost categories to be excluded from the operation of the EBSS.[377]

6.3 TransGrid proposal

6.3.1 Efficiency carry forward mechanism

TransGrid proposed total opex efficiency carryover payments of $17 million ($nominal) from the operation of the ECFM.[378]

6.3.2 Efficiency benefit sharing scheme

TransGrid did not explicitly propose a method for adjusting forecast opex (for EBSS purposes) to account for any difference between forecast demand growth and actual demand growth during the next regulatory control period.

TransGrid did not propose any cost categories for exclusion from the operation of the EBSS in its revenue proposal.

TransGrid, however, indicated its preparedness to work with the AER on both of these issues.

---

374 ACCC, *Statement of principles for the regulation of electricity transmission revenues*, 8 December 2004, p. 14.
375 AER, *TNSP EBSS*, p. 6.
376 AER, *TNSP EBSS*, p. 9.
377 AER, *TNSP EBSS*, p. 5.
378 TransGrid, *Revenue proposal*, pp. 117–118.

6.4 Submissions

The AER received no submissions on the application of the ECFM to TransGrid in the current regulatory control period or the application of the EBSS in the next regulatory control period.

6.5 Issues and AER considerations

6.5.1 ECFM carryover amounts

The ECFM sought to provide TNSPs consistent efficiency incentives by allowing them to retain the benefit of any savings (or expose them to the detriment of any losses) for five years regardless of when in the regulatory control period the savings/losses were made. Consequently, TransGrid will receive during the next regulatory control period ECFM benefits/penalties for efficiency gains/losses made during the current regulatory control period.

TransGrid proposal

TransGrid proposed carryover payments from the operation of the ECFM as shown in table 6.1.

Table 6.1 TransGrid proposed ECFM carryover payments ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Efficiency carry forward	6.3	3.5	4.1	3.9	–0.8

Source: TransGrid, *Revenue proposal*, p. 117.

AER considerations

The AER considers that TransGrid's approach to calculating efficiency gains/losses under the ECFM is not appropriate. TransGrid has expressed the current year's underspend/overspend in current year's dollar terms and subtracted the previous year's underspend/overspend in the previous year's dollar terms—that is, nominal dollar terms for each year. The AER does not consider TransGrid's approach to be appropriate because it treats inflation as an efficiency gain. The opex amounts used in the calculation of efficiency gains/losses should be in consistent dollar terms to meet the requirement in the SRP that the calculation be undertaken in a way that ensures inflation does not erode the value of any benefit or loss.

To ensure all opex amounts are in consistent dollars terms, the AER has inflated the forecast opex and actual opex to 2008–09 dollar terms—that is, real dollar terms of the final year of the current regulatory control period for each year—and has calculated the efficiency gain/loss for each year of the current regulatory control period as shown in table 6.2. These gains/losses are then used to determine the efficiency allowance in accordance with the formulas set out in section 6.2 of this chapter. The calculated efficiency allowances for the next regulatory control period are outlined in table 6.3.

Table 6.2: Efficiency gains/losses under the ECFM ($m, 2008–09)

	2004–05	2005–06	2006–07	2007–08	2008–09
Forecast target opex	135.3	134.8	134.4	134.0	133.8
Actual opex	134.1	134.5	130.9	125.6	129.4[a]
Efficiency gain/loss	1.2	–0.9	3.2	4.9	–3.9

Note: The AER will update the calculation of efficiency gain/loss with the actual CPI for 2008−09 at the time of its final decision.

(a) Actual opex assumed to equal TransGrid's best forecast at the time of making its revenue proposal.

Table 6.3: AER's opex efficiency allowance under the ECFM ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Opex efficiency allowance	4.5	3.2	4.1	1.0	–3.9	8.9

The AER has determined a total opex efficiency allowance of $8.9 million ($2008–09) for TransGrid over the next regulatory control period as shown in table 6.3. See appendix F for a more detailed calculation of TransGrid's opex efficiency allowance under the ECFM.

6.5.2 ECFM error correction mechanism

Since this transmission determination is being made prior to the completion of the current regulatory control period, actual opex in the fifth year of the current regulatory control period has been assumed to be equal to TransGrid's forecast at the time of submitting its revenue proposal. To account for any difference between actual opex and TransGrid's forecast an error correction mechanism will be applied at the revenue reset for the 2014–19 regulatory control period.

TransGrid proposal

TransGrid did not discuss the ECFM error correction mechanism in its revenue proposal.

AER considerations

The efficiency loss of $3.9 million to be carried forward in the final year of the current regulatory control period is estimated using TransGrid's forecast of actual opex for 2008–09 at the time of submitting its revenue proposal. This approach is consistent with the requirements of the ECFM.

The AER will apply an error correction mechanism at the next revenue reset for the 2014–19 regulatory control period to account for any difference between actual opex in 2008–09 and TransGrid's forecast. The adjustment amount arising from the error correction represents the amount TransGrid has been under-compensated or overcompensated depending on whether actual opex for 2008–09 is lower or higher than TransGrid's forecast.

The AER considers that the adjustment amount should be equivalent to the difference between TransGrid's forecast of opex and the actual opex for 2008–09 carried forward to each year of the next regulatory control period, and adjusted for the time value of money (based on the WACC allowed by the AER in this revenue determination for TransGrid as the appropriate discount rate).

The AER notes that there are two approaches available to allocate the adjustment amount within the 2014–19 regulatory control period as a result of the error correction mechanism. First, the AER could adjust TransGrid's MAR in one lump-sum amount in the first year of the regulatory control period. Second, the AER could smooth the error correction by adjusting TransGrid's MAR for equal amounts throughout each year of the 2014–19 regulatory control period. Under both approaches TransGrid would receive the same amount in net present value terms.

The AER considers that there is merit in both approaches and will give further consideration to this issue when making the 2014–19 revenue cap determination, at which time it will be in a better position to assess the appropriateness of each approach. In determining how the adjustment amount is allocated within the 2014–19 regulatory control period, the AER will have regard to the magnitude of the adjustment amount and potential price volatility impacts.

6.5.3 EBSS demand growth adjustment

In developing the EBSS the AER recognised that a TNSP's opex will be affected by the level of demand growth experienced in the network.[379] The EBSS provides that forecast opex is to be adjusted for variances between actual and forecast demand growth. This is intended to prevent TNSPs being penalised/rewarded for changes in opex that are directly attributable to demand growth which is beyond the control of the TNSP.

TransGrid proposal

TransGrid did not explicitly propose a method for adjusting forecast opex for EBSS purposes to account for any difference between forecast demand growth and actual demand growth during the next regulatory control period.

However, TransGrid noted that its proposed opex is based on a link between demand growth and opex through the impact of maintenance of new assets. The forecast commissioning of new assets is based on the capital program that has been generated from a probabilistic analysis of possible load growth scenarios. Consequently, the relationship between opex and growth in assets is representative of an average of a range of demand growth options. Given this, TransGrid proposed that for the purpose of calculating the carryover amounts for the 2014–19 regulatory control period a growth adjustment should only be applied if actual demand is outside the range of scenarios modelled in developing the proposal.[380]

AER considerations

The AER considers TransGrid's proposal for a growth adjustment to only be applied if actual demand is outside the range of scenarios modelled in developing its revenue

[379] AER, *TNSP EBSS*, p. 7.
[380] TransGrid, *Revenue proposal*, p. 118.

proposal is reasonable. Where actual demand is outside the range used, the actual level of demand will be used to recalculate forecast opex requirements, using the modelling process applied in this determination. Consequently, TransGrid's forecast opex will be adjusted for the purpose of calculating carryover amounts if demand growth is greater than the high growth, or less than the low growth scenarios used in forecasting its approved capital expenditure (capex) allowance and outlined in table 6.4.

Table 6.4: Forecast demand growth used to model capex requirements (MW)

	2009−10	2010−11	2011−12	2012−13	2013−14
Low	14 150	14 410	14 790	15 040	15 270
High	14 450	14 850	15 410	15 850	16 290

Source: TransGrid, *NSW Annual planning report 2008*, p. 23.

In the event that actual demand growth is outside the range of scenarios modelled in the development of TransGrid's approved forecast capex (for the purposes of the EBSS) forecast opex will be adjusted based on the same models (opex and capex) used to develop TransGrid's approved forecast opex to incorporate the impact of actual demand growth on the commissioning of new assets.

6.5.4 Excluded cost categories

By default the EBSS excludes the costs of pass through events from the calculation of carryover amounts. In addition, the EBSS allows TNSPs to propose a range of additional cost categories to be excluded from the operation of the EBSS. If additional cost categories are to be excluded, the EBSS requires that the cost categories must be proposed by a TNSP in its revenue proposal for the next regulatory control period.

TransGrid proposal

TransGrid did not propose any cost categories for exclusion from the operation of the EBSS in its revenue proposal. It did state, however, that it was 'prepared to work with the AER to determine other categories that may be appropriate to exclude'.[381]

AER considerations

There are two factors that should be considered when assessing whether an opex category should be excluded from the EBSS. The first factor is whether or not the opex is controllable. The AER does not consider it appropriate for TNSPs to receive benefits or penalties through the EBSS for variances in its opex for cost categories over which it has no control.

The second factor is how actual expenditure for that cost category is used in setting opex forecasts for the following regulatory control period. The EBSS assumes that actual opex is used as a basis for setting future opex allowances. If this is not the case, for instance if opex forecasts for a given cost category were based on an external benchmark, the EBSS would not provide a continuous incentive to reduce opex.

[381] TransGrid, *Revenue proposal*, p. 118.

Applying these factors, the AER considers it appropriate to exclude from the operation of the EBSS for TransGrid over the next regulatory control period the following opex cost categories:

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

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

The AER considers it appropriate that debt raising costs be excluded from the operation of the EBSS on the basis that forecast costs are based on a benchmark efficient firm rather than the historical costs of TransGrid. Similarly self insurance and insurance cost forecasts are based on independent expert analysis rather than historical costs. Consequently, the AER considers it reasonable that they are also excluded from the operation of the EBSS.

The AER notes that a significant number of TransGrid employees are members of defined benefit superannuation schemes. Consequently, TransGrid's superannuation liabilities relating to these employees are impacted, among other things, by the number of these employees that retire in a given year and the performance of the superannuation fund. Given that both of these factors are broadly beyond the control of TransGrid, the AER considers it reasonable that those superannuation costs be excluded from the operation of the EBSS.

The AER also considers that non-network alternatives, such as network support payments, should be excluded from the operation of the EBSS. This ensures that the EBSS does not impact on the incentives for TNSPs to implement non-network alternatives.

6.6 AER conclusion

The AER has determined a total opex efficiency allowance under the ECFM of $8.9 million ($2008–09) for TransGrid over the next regulatory control period as shown in table 6.5.

Table 6.5: AER's opex efficiency allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Opex efficiency allowance	4.5	3.2	4.1	1.0	–3.9	8.9

To account for any difference between actual opex in 2008–09 and TransGrid's forecast, an error correction mechanism will be applied at the next revenue reset. The

adjustment amount will be equivalent to the difference between TransGrid's best forecast of opex for 2008–09 and the actual opex for that year carried forward to each year of the next regulatory control period, adjusted for the time value of money. The adjustment amount will be allocated within the 2014–19 regulatory control period having regard to the magnitude of the adjustment amount and potential price volatility impacts.

The AER will apply the EBSS to TransGrid for the next regulatory control period. In the event that actual demand growth is outside the range of scenarios modelled in the development of TransGrid's approved forecast capex and for the purposes of the EBSS, forecast opex will be adjusted based on the same models (opex and capex) used to develop TransGrid's approved forecast opex to incorporate the impact of actual demand growth on the commissioning of new assets.

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

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

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

The forecast controllable opex for TransGrid outlined in table 6.6 will be used to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS.[382]

Table 6.6: Forecast controllable opex for EBSS purposes ($m, 2007−08)

	2009–10	2010–11	2011–12	2012–13	2013–14
Total forecast opex	153.2	145.1	149.0	157.6	159.8
Adjustment for debt raising costs	–1.9	–2.1	–2.2	–2.4	–2.6
Adjustment for self insurance costs	–1.4	–1.4	–1.4	–1.4	–1.4
Adjustment for insurance costs	–5.9	–6.3	–6.7	–7.1	–7.3
Adjustment for superannuation costs	–6.1	–6.1	–6.1	–6.1	–6.1
Adjustment for non-network alternatives	–22.5	–7.1	–7.1	–7.1	–7.1
Forecast opex for EBSS purposes	115.4	122.2	125.5	133.5	135.4

Note: Totals may not add up due to rounding.

[382] AER, *TNSP EBSS*, p. 7.

7 Depreciation

7.1 Introduction

This chapter sets out the annual allowances for regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB). It also sets out the AER's assessment of TransGrid's proposed asset lives used to calculate its depreciation schedules for the next regulatory control period.

Regulatory depreciation is used to model the nominal asset values over the regulatory control period and provides the depreciation allowance in the annual revenue requirement. The annual regulatory depreciation allowance is an amortised value of the RAB, derived using a specified depreciation schedule that reflects the nature of the assets over their economic life. Regulatory practice has been to assign a regulatory life (standard or remaining) to each category of assets that equals its expected economic or technical life. Generally, the regulatory, economic and technical lives of an asset coincide.

7.2 Regulatory requirements

Clause 6A.6.3(1) of the NER provides that depreciation must be calculated on the value of the assets included in the RAB at the beginning of the regulatory year. A revenue proposal must contain depreciation schedules that conform to the following requirements set out in clause 6A.6.3(b):

> (1) except as provided in paragraph (c), the schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of assets;
>
> (2) the sum of the real value of the depreciation that is attributable to any asset or category of assets over the economic life of that asset or category of assets (such real value being calculated as at the time the value of that asset or category of assets was first included in the regulatory asset base for the relevant transmission system) must be equivalent to the value at which that asset or category of assets was first included in the regulatory asset base for the relevant transmission system; and
>
> (3) the economic life of the relevant assets and the depreciation methodologies and rates underpinning the calculation of actual depreciation for a given regulatory control period must be consistent with those determined for the same assets on a prospective basis in the transmission determination for that period.

To the extent that a TNSP's revenue proposal does not conform with the above requirements then the AER must determine the depreciation schedules, in accordance with clause 6A.6.3(a)(2)(ii) of the NER.

7.3 TransGrid proposal

TransGrid has assigned regulatory asset lives to categories of assets that equate to the assets' expected economic or technical lives. It has applied a straight-line method to

determine systematic allocation of depreciation that is constant across regulatory control periods. TransGrid's proposed regulatory depreciation allowance has been calculated using the post-tax revenue model (PTRM) and is set out in table 7.1.

Table 7.1: TransGrid's proposed regulatory depreciation allowance ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Straight-line depreciation	186.3	201.2	205.7	235.0	259.7	1087.9
Less: inflation adjustment on RAB	106.8	119.3	131.0	150.5	163.7	671.3
Regulatory depreciation	79.6	81.9	74.7	84.5	96.0	416.7

Source: TransGrid, *Revenue proposal*, p. 112.

7.3.1 Recognition of capital expenditure

TransGrid noted that the AER's PTRM guideline adopted the partially as-incurred (hybrid) approach to recognising capex as the default position. TransGrid's current revenue determination is based on recognition of capex on a full as-incurred approach. TransGrid complied with the requirements of the AER's guideline and transition to the hybrid approach in the calculation of its depreciation for the next regulatory control period. It noted this will bring its treatment of recognising capex into line with other TNSPs in the National Electricity Market.[383]

7.4 Issues and AER considerations

The allowance for regulatory depreciation is an output of the PTRM rather than an input to be specified or proposed by the TNSP. The relevant inputs to the PTRM's calculation of an allowance for regulatory depreciation include:[384]

- remaining life for each asset class
- standard life for each asset class
- existing assets (opening RAB) and new asset values (forecast capex) for each asset class.

7.4.1 Standard asset lives and remaining asset lives

The regulatory depreciation allowance is calculated by the PTRM on the basis of remaining and standard asset life inputs, and the opening RAB (discussed in chapter 2) and forecast capex values.

TransGrid proposal

To calculate the regulatory depreciation allowance for existing assets (by asset classes) TransGrid applied the remaining asset lives rolled forward from the start of the current regulatory control period. To determine the remaining lives of the assets at the beginning of the next regulatory control period (2009–10), TransGrid used a

383 TransGrid, *Revenue proposal*, pp. 111–112.
384 Forecast inflation is also a relevant input and is discussed in chapter 4.

weighted average calculation built up from the timing of actual capex incurred during the current regulatory control period.

In calculating the regulatory depreciation allowance for forecast capex, TransGrid proposed to use modified network asset classes that is consistent with the existing asset class definitions but also disaggregated its non-network asset classes into three new asset classes. TransGrid stated that its approach provides a more accurate representation of the economic life of the assets and increases transparency across regulatory control periods.

In proposing the modified network asset classes, TransGrid also split the standard asset lives into two categories—augmentation and replacement. TransGrid stated that replacement assets are generally added to or form part of a larger existing asset. As such, the standard asset lives associated with the replacement category have been reduced by TransGrid to reflect the average remaining life of the existing asset class.[385] The proposed new asset classes and standard asset lives are outlined in table 7.2.

Table 7.2: TransGrid's proposed new asset classes and standard lives (years)

Asset class	Standard asset life
Augmentation category:	
Transmission lines & cables	50
Substations	40
Secondary systems	35
Communications	35
Replacement category:	
Transmission lines & cables	26
Substations	30
Secondary systems	30
Communications	12
Land and easement	n/a
Business IT	4
Support the business – minor plant	8
Motor vehicles & mobile plant	8

Source: TransGrid, *Revenue proposal*, p. 111.

AER considerations

The AER reviewed the remaining asset lives and found that they have been appropriately rolled forward for the start of the next regulatory control period.

In relation to the new asset classes the AER reviewed TransGrid's proposed standard asset lives, with the assistance of Nuttall Consulting, and concludes as follows:

[385] TransGrid, *Revenue proposal*, pp. 110–111.

- Standard asset lives for non-network asset classes—The proposed standard asset lives are broadly consistent with those considered by the AER in recent transmission determinations.[386] The AER considers that they provide depreciation profiles that reflect the nature of those asset classes over their economic lives as required under the NER. TransGrid's proposal is accepted.

- Standard asset lives for network asset classes—The proposed standard lives for two of the asset classes (transmission lines & cables and substations) are lower than those applied for other TNSPs and a case could be made to increase the lives by up to five years. These standard asset lives, however, are generally consistent with those approved by the ACCC for similar asset classes in its 2005 revenue cap decision for TransGrid.[387] On balance, and reflecting general consistency with the previous ACCC determination, the AER accepts TransGrid's proposed standard lives for its network asset classes.

- Augmentation/replacement assets—In general, for the replacement of large assets (e.g. transformer or switchgear) in a substation, it would be expected that the economic life of the replaced asset would be equal to a new development. Even if the remaining life of the substation was less than the technical life of a replaced transformer, the transformer would not be scrapped when the substation was redeveloped. Instead, it would be placed back in service or used as a spare. Similar situations would be expected to occur with other significant assets.

  The AER notes that the proposed approach of standard lives being reduced to the average remaining lives for assets grouped into a replacement category is inconsistent with the treatment by other network service providers of standard lives for replacement assets. The AER is not satisfied with the need to split the standard asset lives between augmentation and replacement asset categories and has decided not to accept the standard asset lives proposed for the replacement asset category of asset classes. TransGrid's proposed replacement forecast capex will therefore need to be reallocated to the augmentation category of asset classes for the purpose of calculating regulatory depreciation in the PTRM.

The standard asset lives approved by the AER for TransGrid are set out in table 7.3.

386 AER, *Final decision – Electranet transmission determination*; and AER, *Final decision – SP AusNet transmission determination*.
387 ACCC, *TNSP PTRM*, confidential.

Table 7.3: AER's conclusion on new asset classes and standard lives (years)

Asset class	Standard asset life
Transmission lines & cables	50
Substations	40
Secondary systems	35
Communications	35
Land and easement	n/a
Business IT	4
Support the business – minor plant	8
Motor vehicles & mobile plant	8

7.4.2 Recognition of capital expenditure

TransGrid proposal

In order to move to recognising its capex on a partially as-incurred approach for the next regulatory control period, TransGrid has proposed a transitional arrangement to accommodate the change in approach.[388]

AER considerations

In its 2005 revenue cap decision for TransGrid, the ACCC determined the capex allowance on an as-incurred basis. Under this approach, capex is rolled into the RAB as spent such that the return on and of capital is modelled when that expenditure is incurred.

In accordance with the NER, the AER's PTRM guideline adopted the partially as-incurred approach to recognising capex. This requires modelling of the return on capital in the year that expenditure is incurred, while the return of capital is modelled on an as-commissioned basis.

TransGrid's revenue proposal has adopted the partially as-incurred approach to recognising capex for the next regulatory control period. To facilitate a smooth transition to this approach, TransGrid proposed that capex for committed projects that span the current and next regulatory control periods will continue being recognised on an as-incurred basis until the project is commissioned for the purposes of modelling the return of capital. The AER has reviewed the proposed method and agrees that it has been implemented appropriately in the PTRM.

7.5 Conclusion

The AER has assessed each of the proposed asset class lives in the PTRM, that are used to calculate the regulatory depreciation allowance in accordance with clause 6A.6.3 of the NER. The AER has revised some of TransGrid's proposed asset class lives to standardise the treatment of standard lives for replacement asset classes with augmentation asset classes. As noted in section 7.4, the AER considers that TransGrid's proposed depreciation schedules do not conform with the NER

[388] TransGrid, *Revenue proposal*, p. 112.

requirements and therefore has recalculated the depreciation allowance for this draft decision. The AER has also reviewed TransGrid's proposed method for transitioning to recognise its capex on a partially as-incurred approach and agrees that it has been implemented appropriately in the PTRM.

On the basis of the approved asset lives, opening RAB, forecast capex allowance and the transitional arrangement to recognise capex on a partially as-incurred approach, the AER has determined TransGrid's regulatory depreciation allowance for the next regulatory control period in accordance with clause 6A.6.3(a)(2)(ii), as set out in table 7.4.

Table 7.4: AER's conclusion on regulatory depreciation allowance ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Straight-line depreciation	179.9	193.1	195.5	218.4	240.7	1027.6
Less: inflation adjustment on RAB	108.0	120.5	130.9	144.9	158.0	662.3
Regulatory depreciation	71.9	72.6	64.6	73.5	82.7	365.3

8 Service target performance incentive scheme

8.1 Introduction

The AER's service target performance incentive scheme (the scheme) aims to encourage TNSPs to maintain or improve the quality of service provided to customers.[389] This chapter sets out TransGrid's proposal, PB's review and the AER's considerations of the service target performance regime and values to be applied to TransGrid for the next regulatory control period.

Under a revenue cap regime, TNSPs can increase their profits for regulated activities by reducing their operating costs. Such cost reductions could result from efficiency gains or by allowing service levels to decline. The latter imposes costs on other market participants.

The scheme provides an incentive to TNSPs not to lower service levels when seeking to reduce operating costs and also to consider the interests of users when making operational management decisions. However, the scheme does not encourage TNSPs to seek performance improvements where the cost of the improvements exceeds the benefits to users.

The scheme has two components: a service component and a market impact of transmission congestion (MITC) component. The service component of the scheme applied to TransGrid in the current regulatory control period. It provides incentives in the operation of the network to maximise transmission circuit availability, minimise loss of supply event frequency and minimise average outage duration. This means that TNSPs need to consider the impact of their actions on customers when making operational management decisions, such as taking lines out of service for maintenance or augmentation.

The AER has recently developed an additional scheme component based on the MITC. The market impact component will apply to TransGrid during the next regulatory control period. The market impact component supplements the service component of the scheme by targeting outages that have an adverse impact on generator dispatch outcomes. The scheme incorporates a market impact parameter based on historical MITC data and provides financial rewards for improvements in performance standards against a performance target.

8.2 Regulatory requirements

8.2.1 NER requirements

Clause 6A.7.4 of the NER required the AER to publish a scheme by 28 September 2007 that complied with the principles in clause 6A.7.4(b) of the NER. The AER published a second version of the scheme in March 2008 to apply to

[389] AER, *Electricity transmission network service providers – Service target performance incentive scheme*, March 2008.

TransGrid for its next regulatory control period.[390] The second version of the scheme includes a market impact component based on the MITC as part of the broader scheme. References to the scheme in this chapter should be read as a reference to the second version of the scheme.

The scheme sets out the parameters that apply to TransGrid as well as the requirements for performance targets, caps, collars and weightings. The AER is required to assess TransGrid's proposed performance targets, caps, collars and weightings against the requirements of the scheme and the NER.

The AER's objectives for the scheme are that it:

- contributes to the achievement of the national electricity objective
- is consistent with the principles in clause 6A.7.4(b) of the NER
- promotes transparency in the information provided by a TNSP to the AER and the decisions made by the AER
- assists in the setting of efficient capital and operating and maintenance expenditure allowances by balancing the incentive to reduce actual expenditure with the need to maintain and improve reliability for customers and reduce the market impact of transmission congestion.[391]

8.3 TransGrid proposal

TransGrid's proposed performance targets, caps, collars and weightings for each of the parameters that apply to it under the service component of the scheme are set out in table 8.1.

TransGrid's proposal for the market impact component is based on the number of five minute dispatch intervals where an outage on its network results in a network outage constraint with a marginal value greater than $10/MWh.[392] TransGrid's proposed market impact component parameter values and weighting are outlined in table 8.2.

[390] AER, *TNSP STPIS*.
[391] AER, *TNSP STPIS*, p. 3.
[392] The marginal value is an indication of the change, at the margin, in the cost of producing electricity due to a network outage.

Table 8.1: TransGrid's proposed values and weightings

Parameter	Proposed Values			
	Collar	**Target**	**Cap**	**Weighting**
Transmission circuit availability (%)				*MAR (%)*
Transmission line availability	98.92	99.12	99.24	0.20
Transformer availability	97.29	98.58	98.85	0.15
Reactive plant availability	98.67	99.13	99.33	0.10
Loss of supply event frequency (no.)				*MAR (%)*
> 0.05 (x) system minutes	7	4	2	0.25
> 0.25 (y) system minutes	2	1	0	0.10
Average outage duration (minutes)				*MAR (%)*
Total	917	790	663	0.20

Source: TransGrid, *Revenue proposal*, p. 107.

Table 8.2: TransGrid's proposed market impact parameter values and weighting

Parameter	Proposed Values		
Market impact parameter	**Target**	**Cap**	**Weighting**
	Number of dispatch intervals with a marginal value greater than $10/MWh		*MAR (%)*
	2858[a]	0	2.0

Source: TransGrid, MITC performance data template, 9 June 2008.
(a) Note that the proposed performance target in TransGrid's revenue proposal at page 106 differs to the proposed performance target in the MITC performance data template that accompanied the revenue proposal. TransGrid confirmed that the proposed performance target in the MITC performance data template was the correct figure and should be taken as TransGrid's proposed performance target for the purpose of the AER's review.

8.4 Submissions

Two submissions commented on the service and market impact components of TransGrid's proposed service target performance regime.

Service component

The Energy Users Association of Australia (EUAA) considered that an asymmetric incentive is inappropriate. It stated that TransGrid had not provided any benchmark

information or technical advice to support adjusting its proposed performance values for capital works.[393]

The Energy Markets Reform Forum (EMRF) considered that availability targets should not be adjusted for the increase in capital works. It stated that targets should, at a minimum, be based on recent average performance.[394]

Market impact component

The EUAA recommended that TransGrid's market impact component be based on a term of five years, not the four years proposed by TransGrid. The EUAA also recommended that the AER investigate options for determining metrics that link performance to the regulatory control period rather than using historical values.[395]

8.5 Consultant review

The AER engaged PB to review TransGrid's data collection processes and its proposed performance targets, caps, collars and weightings.

PB recommended a number of changes to performance targets, caps and collars proposed in TransGrid's revenue proposal (for which supporting revisions and updated forecasts were submitted by TransGrid). PB also noted that TransGrid's proposed weightings were reasonable and provided appropriate incentives to maintain and improve reliability for customers.

Table 8.3 lists PB's recommended performance targets, caps, collars and weightings.

Table 8.3: PB's recommended performance targets, caps, collars and weightings

Parameter	Recommended values			
	Collar	**Target**	**Cap**	**Weighting**
Transmission circuit availability (%)				*MAR (%)*
Transmission line availability	99.05	99.26	99.36	0.20
Transformer availability	97.26	98.55	98.84	0.15
Reactive plant availability	98.65	99.12	99.33	0.10
Loss of supply event frequency (no.)				*MAR (%)*
> 0.05 (x) system minutes	7	4	2	0.25
> 0.25 (y) system minutes	2	1	0	0.10
Average outage duration (minutes)				*MAR (%)*
Total	999	824	649	0.20

Source: PB, *APR 2008 Supplementary report*, p. 46.

[393] EUAA, p. 31.
[394] EMRF, pp. 24–26.
[395] EUAA, p. 32.

8.6 AER issues and considerations—service component

8.6.1 Parameter definitions

Appendix B of the scheme prescribes and defines the parameters that apply to TransGrid under the service component. While each of the parameters and their respective definitions were determined during the development of the scheme the AER has, in consultation with TransGrid, defined the formula for calculation of system minutes used for the loss of supply event frequency parameter. The formula is reproduced below.

Parameter 2 Loss of supply event frequency

Definition/formula	number of events greater than 0.05 system minutes per annum number of events greater than 0.25 system minutes per annum system minutes are calculated for each supply interruption by the 'load integration method' using the following formula: $$\frac{\Sigma \text{ (MWh unsupplied x 60)}}{\text{MW peak demand}}$$ where: MWh unsupplied is the energy not supplied as determined by using NEM metering and substation load data. This data is used to estimate the profile of the load over the period of the interruption by reference to historical load data period of the interruption starts when a loss of supply occurs and ends when TransGrid offers supply restoration to the customer MW peak demand means the maximum amount of aggregated electricity demand recorded at entry points to the TransGrid transmission network and interconnector connection points during the reporting period in which the event occurs the performance parameter applies to exit points only an interruption >0.25 system minutes also registers as a >0.05system minutes event

8.6.2 Data collection, data reporting and exclusions

Consultant review

PB reviewed TransGrid's data collecting and reporting systems and TransGrid's service standards compliance reporting data and audit reports that were available from 2003 to 2007.[396] PB noted that TransGrid's data collection and reporting systems had largely relied on manual processes up to mid-2007. Since then TransGrid has implemented an online system to record planned outages and a new data collection and reporting system will be implemented in 2008.

PB conducted a review of the exclusions claimed by TransGrid as part of the service standards compliance reviews during 2003 to 2007. TransGrid uncovered a number of minor data discrepancies while gathering data to provide to PB. The corrected data was analysed by PB and it found the excluded events appeared to meet the criteria for exclusions under the scheme.[397]

PB concluded that TransGrid's historical data was suitable for setting performance targets and that its data collection systems and processes appeared suitable for future use under the scheme.[398] Table 8.4 outlines TransGrid's actual performance from 2003 to 2007.

Table 8.4: TransGrid service standards performance from 2003–2007

	Actual performance					
Parameter	**2003**	**2004**	**2005**	**2006**	**2007**	**Average**
Transmission line availability (%)	99.62	99.67	99.51	99.56	99.38	99.55
Transformer availability (%)	99.00	99.31	98.90	98.84	97.46	98.70
Reactive plant availability (%)	99.34	99.42	99.63	98.92	99.22	99.31
Loss of supply event frequency event >0.05 system minutes (no.)	9	1	1	2	5	3.6
Loss of supply event frequency event >0.25 system minutes (no.)	1	1	0	0	1	0.6
Average outage duration (min.)	830	726	723	928	911	824

Source: PB report, p. 232.

AER considerations

TransGrid has been subject to a service standards compliance review conducted by the ACCC/AER for the past four years. The compliance reviews have consistently shown that TransGrid's service standards reporting is accurate, however it is heavily reliant on manual processes which has the inherent risk of error. The AER notes that TransGrid has recently implemented an online system to record planned outages

396 PB noted that data prior to July 2004 and data for 2007 had not been subject to external engineering audit.
397 PB, p. 231.
398 PB, p. 230.

which should improve its data collection and reporting systems by removing some of the manual processes.

During the next regulatory control period TransGrid's data collection and reporting systems will be subject to a compliance review against the scheme by the AER and its consultants. The AER is satisfied that TransGrid's data collection and reporting processes are appropriate.

8.6.3 Performance targets

Performance targets define a level of performance for each parameter at which TransGrid will not receive a financial reward or penalty in the relevant regulatory year.

TransGrid proposal

TransGrid noted that the majority of outages are planned to meet regulatory obligations related to capital works, maintenance and major refurbishments. It stated that the volume of capital works in the next regulatory control period will impact on the transformer and transmission line availability parameters.[399] TransGrid considered that improvements in transmission circuit availability parameters are not possible and future performance targets need to be adjusted to reflect its capital works program.[400] TransGrid's proposed performance targets for the transmission circuit availability parameters have been calculated by adjusting the average performance over the five-year period from 2003 to 2007 by the forecast change in the level of capital works in the next regulatory control period.

On 22 August 2008, TransGrid provided the AER with an updated capital works forecast based on its 2008 annual planning report (APR). The original forecast of capital works was based on the 2007 APR. As TransGrid's transmission circuit availability parameter performance targets have been adjusted to account for the expected increase in outages associated with its proposed capital works program, the change in forecast capital works has had a material impact on TransGrid's proposed performance targets. The revised performance targets are outlined in table 8.5.

Table 8.5: TransGrid's revised proposed transmission circuit availability performance targets (per cent)

Parameter	Revised proposed target
Transmission line availability	99.26
Transformer availability	98.55
Reactive plant availability	99.12

Source: TransGrid, *Revised STPIS values*, email, 22 August 2008.

TransGrid proposed performance targets for its loss of supply event frequency parameters based on its average performance over the past five years from 2003 to

[399] TransGrid, *Revenue proposal*, p. 99.
[400] TransGrid, *Revenue proposal*, p. 99.

2007.[401] The average loss of supply event frequency greater than 0.05 system minutes was determined to be 3.6 events and rounded to the nearest integer. The average loss of supply event frequency greater than 0.25 system minutes was determined to be 0.6 events and was also rounded to the nearest integer.

TransGrid also averaged its performance data from 2003 to 2007 to determine its proposed average outage duration performance target of 790 minutes.[402]

TransGrid's proposed performance targets for all its parameters are listed in table 8.1.

Submissions

The EUAA and EMRF considered that TransGrid's performance targets should not be adjusted for changes in the level of capital works.[403]

Consultant review

PB reviewed the performance targets proposed by TransGrid and recommended the targets outlined in table 8.3.

Transmission circuit availability

PB noted that TransGrid's proposed adjustments to performance targets for capital works were based on a bottom up assessment of the outage hours for future capex projects. It reviewed TransGrid's calculation of outage times by considering outage hour estimates and timing. Where a project's proposed completion date varied depending on the scenarios used to forecast capex, TransGrid proposed to use the median of the completion dates to determine if the outage hours should be included or excluded from the service performance calculation for the next regulatory control period.

PB noted that using the median may result in more outage hours being included in the calculation of forecast capex and in turn affect the calculation of the transmission circuit availability targets. PB tested TransGrid's median approach by comparing it with the probabilistic approach adopted for forecasting capex. PB found only one project completion date changed and concluded that using the probabilistic approach to predict completion dates rather than the median has little impact on the calculation of the performance targets.

PB also stated that where a project does not appear in all scenarios, the outage hours should be reduced to reflect the reduced likelihood of the project proceeding. It tested the effect of TransGrid not reducing outage hours by multiplying the outage hours by the sum of the probabilities of the relevant scenarios. PB found three projects were affected, however, this had an immaterial effect on TransGrid's proposed targets and therefore PB did not recommend any adjustments.

PB also conducted a review of the expected outage hours for the five most significant projects. It found that TransGrid had assigned 10 080 outage hours to the Bannaby to South Sydney 330 kV project. The project involves the removal of the 330 kV line

401 TransGrid, *Revenue proposal*, p. 104.
402 TransGrid, *Revenue proposal*, p. 105.
403 EUAA, p. 31;
EMRF, pp. 25–26.

and construction of a new 500 kV line. TransGrid proposed to commence work on the project, return the 330 kV line to service for the summer period and then remove the line from service after the summer period. PB recommended that only the outage hours associated with the project up to its removal from service during the summer period be excluded from the adjustments to performance targets as this line is effectively excluded from the scheme after the summer period.[404]

Following the release of the 2008 APR, TransGrid advised that the outage hours for the Bannaby to South Sydney 330 kV project should be reduced further as some of the outages associated with this project are now scheduled to occur in the regulatory control period commencing 1 July 2014.[405]

In reviewing the data for transformer availability PB noted the performance target was based on an incorrect calculation of average historical performance. PB's calculations determined that average historical performance is 98.70 per cent rather than 98.72 per cent proposed by TransGrid in its revenue proposal.

Based on its review of TransGrid's proposed transmission circuit availability parameter performance targets and taking into account the incorrect historical average for transformer availability and the revised values due to the 2008 APR, PB recommended the adjustments outlined in table 8.6.

Table 8.6: Impact of PB's adjustments to transmission circuit availability parameters performance targets (per cent)

Parameter	Historical average	Adjustment for capital works	Recommended target
Transmission line availability	99.55	–0.29	99.26
Transformer availability	98.70	–0.15	98.55
Reactive plant availability	99.31	–0.19	99.12

Source: PB, supplementary report, p. 46.
Note: In August 2008, TransGrid advised the AER that it was reducing its forecast capex program which had a material effect on its scheme parameter targets. The figures in table 6.2, page 46, of PB's supplementary report reflect that reduction.

Loss of supply

PB reviewed TransGrid's proposed loss of supply event frequency performance targets based on the most recent five years of historical data and recommended that the AER accept the proposed targets. PB noted that TransGrid had engaged SAHA International (SAHA) to determine suitable values for this parameter—SAHA had recommended that at least a 10 year horizon be adopted for developing the targets.[406]

404 PB, p. 233.
405 PB, APR 2008 s*upplementary report*, pp. 45–46.
406 SAHA, *Service target performance incentive scheme: targets, caps and collars relating to the loss of supply event frequency parameter*, 11 March 2008, pp. 9, 11–12.

PB further noted that the proposed targets were the same as those based on the average of 10 years of historical data (following rounding to the nearest integer).[407]

Average outage duration

PB reviewed TransGrid's proposed average outage duration parameter performance target. Subsequent to lodging its revenue proposal with the AER TransGrid provided PB and the AER with a list of outages over the 2003 to 2007 period. TransGrid noted a number of discrepancies between this list and the information provided with its revenue proposal. PB recalculated the average outage duration data for the most recent five years using the list of outages and based on its calculations, recommended the average outage duration parameter performance target be set at 824 minutes.[408]

AER considerations

Under clause 3.3 of the scheme, performance targets must be equal to the TNSP's average performance history over the most recent five years. However, the AER may approve a performance target based on an alternative period if it is satisfied that the period is consistent with the objectives of the scheme.

Clause 3.3(k) of the scheme permits adjustments to performance targets for the expected effects on a TNSP's performance from any increases or decreases in the volume of capital works forecast for the next regulatory control period compared to the volume of capital works in the period over which the targets are determined.

Transmission circuit availability

The AER has reviewed TransGrid's proposed performance targets for the transmission circuit availability parameters and considered PB's advice. The AER found that the proposed performance targets are based on the most recent five years of historical data and have been subject to reasonable adjustment to allow for the expected increase in capital works in the next regulatory control period.

The AER notes the concerns raised by PB regarding the method of estimating outage lengths and the likelihood of some projects not proceeding. However, given PB's analysis indicated that this would have an immaterial effect on the proposed adjustment, the AER accepts TransGrid's proposed methodology for adjusting its performance targets.

The AER notes the concerns of the EUAA and the EMRF about the adjustment of TransGrid's historical average performance to account for the forecast increase in capital works.

Adjustments to performance targets are allowed under the scheme in recognition that where there is a substantial change in a TNSP's capital works program, historical performance may not be an achievable goal for future performance. The service component of the scheme is primarily concerned with influencing the operational management decisions of TNSPs to ensure that they consider the interests of users when seeking to reduce operating expenditure. Where there is a material change in the outages associated with an increased capital works program, operational management decisions alone may not make it possible for the TNSP to achieve a performance

[407] PB, p. 234.
[408] PB, p. 235.

target based on historical performance due to the large number of outages required. In these circumstances the incentive mechanism will be undermined if there is no adjustment to the performance target.

The AER and PB have reviewed the data provided by TransGrid to support its proposed adjustments to the historical average based on forecast capital works and are satisfied that the adjustments are reasonable. The proposed performance target is lower than TransGrid's historical average performance as an adjustment was made to take account of the expected increase in capital works outages in the next regulatory control period.

The AER notes that under clause 3.3(d) of the scheme, data used to calculate parameter values must be accurate and reliable. Further, clause 3.3(k)(2) provides for proposed targets to be subject to reasonable adjustment to allow for the increase and decrease in the volume of capital works planned for the next regulatory control period.

The AER has considered the recommendations made by PB with respect to the reduction of forecast capital works outage hours and the averaging of historical data. It also considered the adjustments to performance targets proposed by TransGrid following the publication of the 2008 APR. Taking into account the discrepancies in the historical data identified by PB and TransGrid and the revised values provided by TransGrid following the release of the 2008 APR, the AER does not accept the performance targets proposed by TransGrid in its revenue proposal for the transmission circuit availability parameters. However the AER accepts the revised performance targets provided by TransGrid on 22 August 2008 for its next regulatory control period. These performance targets are listed in table 8.8.

Loss of supply

The AER accepts TransGrid's proposed loss of supply event frequency parameter performance targets as they are based on the average performance of the most recent five years and meet the requirements of the scheme.

Average outage duration

The AER notes the discrepancies in the average outage duration parameter historical data identified by PB and TransGrid during the review process. PB recalculated the average outage duration parameter performance target based on TransGrid's revised data from 2003 to 2007 and recommended a target of 824 minutes.

The AER notes that under clause 3.3(d) of the scheme, data used to calculate proposed values must be accurate and reliable. Due to the discrepancies identified by PB and TransGrid, the AER does not accept the average outage duration parameter performance target proposed in TransGrid's revenue proposal. The AER considers the performance target recommended by PB meets the requirements of the scheme and substitutes the performance target listed in table 8.8 for TransGrid's next regulatory control period.

8.6.4 Caps and collars

The cap and collar for each parameter define the range of performance within which TransGrid will receive a financial reward or penalty. The cap and collar also

determine the rate at which TransGrid will receive a bonus or penalty based on its annual performance. The cap is the performance value that results in the maximum financial reward for any one parameter and the collar is the performance value that results in the maximum financial penalty.

TransGrid proposal

TransGrid proposed to set the transmission circuit availability parameter collars at two standards deviations below the target. It considered this approach to be consistent with recent AER determinations. TransGrid proposed to set the cap at a level that allows best practice maintenance and forecast capital works to be carried out. It stated that the cap was calculated by forecasting outages based on best practice maintenance and efficient capital works and adjusting for an efficiency factor of 10 per cent.[409] It stated that the caps were consistent with the requirements of the scheme as they were calculated with reference to the performance target by adding average unavailability due to forced and emergency outages to its proposed performance target and applying an efficiency factor to provide incentives for further increases in availability.[410]

On 22 August 2008, TransGrid provided the AER with an updated capital works forecast based on its 2008 APR. The original capital works forecast was based on the 2007 APR. The change in forecast capital works has had a material impact on TransGrid's proposed transmission circuit availability parameter caps and collars. These changes are outlined in table 8.7.

Table 8.7: TransGrid's revised proposed availability performance targets (per cent)

Parameter	TransGrid's revised cap	TransGrid's revised collar
Transmission line availability	99.36	99.06
Transformer availability	98.84	97.26
Reactive plant availability	99.33	98.66

Source: TransGrid, *Revised STPIS values*, email, 22 August 2008.

TransGrid engaged SAHA to advise it on proposing loss of supply event frequency caps and collars. SAHA considered that using data over a longer time period provides a more accurate estimate.[411] It considered use of the standard deviation approach is not recommended for setting caps and collars for the loss of supply event frequency parameter as outage distribution is not symmetrical. Instead SAHA recommended setting caps and collars using a 10 or 15 year timeframe based on the 10th and 90th percentile.[412] TransGrid stated that a 10 year period was used due to the small number of events and to reflect the long-term performance of its network.[413]

409 TransGrid, *Revenue proposal*, pp. 101–104.
410 TransGrid, *Service target performance incentive scheme, Supporting documentation, Serv 001*, 5 June 2008, pp. 11–17.
411 SAHA, *STPIS*, p. 8.
412 SAHA, *STPIS,* pp. 10, 12.
413 TransGrid, *STPIS, supporting documentation*, 5 June 2008, p. 19.

TransGrid proposed to set the average outage duration cap and collar at two standard deviations either side of the target which results in a 95 per cent probability that the outcome will be placed on the resulting curve.[414]

TransGrid's proposed caps and collars for each parameter are listed in table 8.1.

Submissions

The EUAA stated that it was opposed to an asymmetric incentive being applied to TransGrid's service performance in the next regulatory control period.[415]

Consultant review

PB reviewed TransGrid's proposed caps and collars. It considered that where performance is normally distributed, caps and collars should ideally be about two standard deviations from the average of historical data resulting in the cap or collar being reached one in every twenty years.[416]

Collars

In considering the parameter collar values, PB noted that TransGrid proposed to set the transmission circuit availability parameter and average outage duration parameter collar values by calculating two standard deviations below its proposed performance target. PB noted that the loss of supply event frequency parameters collars are proposed to be set at the 90th percentile using the curve of best fit. PB noted that in this case using the 95th percentile applied over the 15 year time period would result in a significantly lower incremental penalty for each loss of supply event. For example for the loss of supply event frequency >0.05 system minutes, it would increase the collar by three events and reduce the cap by one event. PB concluded that the approach proposed by TransGrid results in more appropriate cap and collar values that better reflect recent performance.

It also noted that 10 years of historical data has been used to set the loss of supply event frequency collar values and, given the small number of loss of supply events over the most recent five–year period, the longer time period should better capture the variability in the parameter.[417]

PB considered TransGrid's approach to setting the collar values for its parameters resulted in suitable values.[418]

Caps

PB noted TransGrid's proposed approach to setting transmission circuit availability parameter caps and considered TransGrid's proposed approach to setting transmission circuit availability parameter caps provides a reasonable performance improvement goal.[419]

414 TransGrid, *Revenue proposal*, p. 106.
415 EUAA, p. 31.
416 PB, p. 236.
417 PB, p. 236.
418 PB, pp. 236–237.
419 PB, pp. 236–237.

PB reviewed TransGrid's proposal to set the loss of supply event frequency parameters caps at the 10th percentile of the curve of best fit using 10 years of historical data. It noted that this method, after rounding, resulted in an asymmetrical reward/penalty for the loss of supply event frequency greater than 0.05 system minutes parameter and a symmetrical reward/penalty for the loss of supply event frequency greater than 0.25 system minutes parameter.[420]

PB noted that TransGrid proposed to set the average outage duration parameter cap by calculating two standard deviations from the performance target value. While it agreed with this process, PB noted that due to the recalculation of TransGrid's average outage duration parameter target, the cap would change accordingly.[421]

AER considerations

Under clause 3.3(e) of the scheme proposed caps and collars must be calculated by reference to the proposed performance targets using a sound methodology. Further, clause 3.3(e) of the scheme states that adjustments to the proposed performance targets may result in adjustments to the proposed caps and collars. The AER notes the concerns expressed by the EUAA on the application of an asymmetric incentive.

However, under clause 3.3(f) of the scheme, a proposed cap and collar may result in symmetric or asymmetric incentives for a TNSP. An asymmetric incentive may be appropriate where a TNSP is operating at a high level of performance or has limited ability to improve performance any further. In these circumstances, asymmetric cap and collar values may be appropriate in recognition that it will be more difficult for a TNSP to experience further performance improvements and relatively easy for it to experience a decline in performance levels.

Collars

The AER accepts TransGrid's proposed methodology for setting the collar values for the transmission circuit availability and average outage duration parameters which have been based on calculating two standard deviations from the performance target. The standard deviation approach is also consistent with previous revenue determinations.

While TransGrid's proposed methodology is acceptable, the transmission circuit availability parameter performance targets have been revised by TransGrid for adjustments to forecast capital works and data errors identified by PB and TransGrid during the review process. Consistent with clause 3.3(e) of the scheme, as adjustments have been made to the proposed performance targets, adjustments may also be made to the proposed caps and collars. Therefore the AER does not accept the transmission circuit availability parameters collar values proposed by TransGrid in its revenue proposal. The AER substitutes the collar values recommended by PB and listed in table 8.8 for TransGrid's next regulatory control period. These values are slightly different to the revised values provided by TransGrid on 22 August 2008 due to differences in rounding.

The AER supports the approach recommended by SAHA for setting the collar values for the loss of supply event frequency parameters using 10 years of historical data.

---

420 PB, p. 236.
421 PB, p. 236.

Given the inherent variability in the loss of supply performance data and the relatively small number of events which occurred in the five year period, using a longer time period to establish the collar values is appropriate. The AER also accepts SAHA's approach of applying a distribution function that best fits the actual data set and using the 90^{th} and 10^{th} percentiles to determine caps and collars. This provides TransGrid with an equal probability of reaching the cap or collar values and is appropriate given the asymmetric historical data. Given this, the AER accepts TransGrid's proposed collar values for the loss of supply event frequency parameters.

The performance target for the average outage duration parameter was also revised during PB's review and as a result, in accordance with clause 3.3(e) of the scheme, the collar values have also been revised. For this reason the AER does not accept the collar values proposed by TransGrid in its revenue proposal for the average outage duration parameter. The AER substitutes the collar values recommended by PB and listed in table 8.8 for TransGrid's next regulatory control period.

Caps

The AER accepts the method proposed by TransGrid for calculating the cap values for transmission circuit availability parameters. TransGrid has demonstrated the calculation of the cap values with reference to the proposed performance target as required under the scheme and its methodology is appropriate. The proposed cap provides TransGrid with a difficult, but achievable performance cap for the next regulatory control period.

However, as the performance targets for transmission circuit availability parameters were revised due to the adjustments to forecast capital works and the discrepancies in the historical data identified by TransGrid and PB, the AER, in accordance with clause 3.3(e) of the scheme, does not accept the proposed cap values in TransGrid's revenue proposal. The AER accepts the revised caps provided by TransGrid on 22 August 2008 for its next regulatory control period. These caps are listed in table 8.8.

As discussed in the section on collars above, the AER supports the approach recommended by SAHA for setting the cap values for the loss of supply event frequency parameters using ten years of historical data. SAHA's approach results in an equal probability of TransGrid reaching the cap or the collar. The AER accepts TransGrid's proposed cap values for the loss of supply event frequency parameters.

The AER accepts TransGrid's proposed methodology for calculating the cap for the average outage duration parameter by calculating a value two standards deviations above the performance target. However, as the performance target value changed due to the data discrepancies, the cap value has also changed, consistent with clause 3.3(e) of the scheme. Therefore the AER does not accept TransGrid's proposed cap value for the average outage duration parameter and substitutes the cap value listed in table 8.8 for TransGrid's next regulatory control period.

8.6.5 Weightings

Weightings are the proportion that each parameter contributes to TransGrid's maximum financial reward or penalty under the scheme.

TransGrid proposal

In the next regulatory control period TransGrid's large loss of supply events (greater than 0.25 system minutes) will also be counted as smaller loss of supply events (greater than 0.05 system minutes). As a result, TransGrid proposed to reduce the revenue at risk for loss of supply events greater than 0.25 system minutes to 0.1 per cent of its MAR. (The loss of supply event frequency greater than 0.4 system minute parameter that applies in the current regulatory control period has a weighting of 0.2 per cent of MAR). It proposed reallocating the remaining 0.1 per cent to the average outage duration parameter as it considered that it had the greatest scope for performance improvement for this parameter.[422] TransGrid's proposed weightings are listed in table 8.1.

Consultant review

PB stated that parameter specific weightings should be set such that they provide a material incentive. It considered that a weighting set at less than 0.1 per cent of MAR provides a weak incentive.[423]

PB also stated that the loss of supply event frequency greater than 0.25 system minutes parameter should be allocated the highest weighting to match transmission customers' high expectations with respect to reliability of supply.[424] PB noted that large loss of supply events (greater than 0.25 system minutes) will also be included in the loss of supply event frequency greater than 0.05 system minutes. This means that the total weighting applied to large loss of supply events will be 0.35 per cent of the MAR.

PB considered that TransGrid's proposed weightings are reasonable and provide appropriate incentives to maintain and improve reliability for customers.[425]

AER considerations

The AER notes that the only proposed changes to TransGrid's weightings, compared to those in place for the current regulatory control period, involve:

- the reduction of the loss of supply event frequency greater than 0.25 system minutes parameter[426] weighting from 0.2 per cent to 0.1 per cent of MAR and
- an increase in the average outage duration parameter weighting from 0.1 per cent to 0.2 per cent of MAR.

The reduction in the large loss of supply event frequency threshold from 0.4 to 0.25 system minutes represents a tighter target for TransGrid. The AER also notes that TransGrid will be required to count large loss of supply events as small loss of supply events in the next regulatory control period. Therefore the AER considers TransGrid's proposed reduction in the weighting to apply to the large loss of supply event frequency parameter is reasonable.

---

422 TransGrid, *Revenue proposal*, pp. 106–107.
423 PB, p. 238.
424 PB, p. 238.
425 PB, p. 238.
426 In the current regulatory control period, the threshold for the parameter measuring large loss of supply event frequency was set at greater than 0.4 system minutes.

TransGrid has historically performed well against its transmission circuit availability parameters which have a combined weighting of 0.45 per cent of MAR, therefore it would be inappropriate to allocate the remaining 0.1 per cent of MAR to one of the availability parameters. The AER notes that TransGrid has historically performed very well against its average outage duration parameter, however, its target for the next regulatory control period will be considerably lower than that which applied for the current regulatory control period. To increase the incentive on the average outage duration parameter the AER agrees that the remaining 0.1 per cent of MAR should be applied to this parameter.

The AER accepts TransGrid's proposed weightings set out in table 8.1. The AER considers that the proposed weightings are consistent with the requirements of clause 3.5 of the scheme and the overall objectives of the scheme.

8.7 AER issues and considerations—market impact component

TransGrid's market impact parameter is the number of five-minute dispatch intervals where an outage on TransGrid's network results in a network outage constraint with a marginal value greater than $10/MWh,[427] for a calendar year.

TransGrid will receive a financial reward if its performance parameter outperforms its approved performance target. The scheme prescribes that the cap for the market impact parameter must equal zero dispatch intervals and the maximum revenue increment is two per cent of TransGrid's MAR for the relevant calendar year. There is no penalty if the performance target is not met. TransGrid's proposed performance target for the market impact component and the AER's considerations are discussed below.

TransGrid proposal

TransGrid proposed to set the performance target for the market impact parameter at 2858 dispatch intervals.[428] This performance target was calculated by taking an average of TransGrid's performance against the parameter for the period of 2004 to 2007. The AER notes that the proposed performance target for the market impact parameter in TransGrid's revenue proposal at page 106 differs to the proposed performance target in the MITC performance data template that accompanied the revenue proposal. TransGrid confirmed that the proposed performance target in the MITC performance data template was the correct figure.[429]

Submissions

The EUAA recommended that TransGrid's market impact component be based on a term of five years, not the four years proposed by TransGrid. It stated that the four years proposed by TransGrid was inconsistent with the five year period applicable for the service component and the length of the regulatory control period.[430] The EUAA

[427] The marginal value is an indication of the change, at the margin, in the cost of producing electricity due to a network outage.
[428] TransGrid, *MITC performance data template*, 10 June 2008.
[429] TransGrid, response to AER information request, 27 June 2008.
[430] EUAA, p. 32.

also recommended that the AER investigate options for determining metrics that link performance to the regulatory control period rather than using historical values.[431]

AER considerations

Under clause 4.2(d) of the scheme, the performance target for the market impact parameter must be equal to the TNSP's average performance history over the most recent five years. However under clause 4.2(e) of the scheme, the AER may approve the performance target based on a different period if it is satisfied that the use of a different period is consistent with the scheme's objectives.

When developing the market impact component, the AER proposed to set TransGrid's performance target based on four years of market data rather than five because it coincided with the detailed analysis undertaken by the AER to produce the annual market congestion reports, which commenced in June 2003. The AER has published the 2003–04 to 2006–07 reports and is currently in the process of completing the 2007–08 report. Therefore four calendar years of analysed data is available (2004 to 2007).

During the development of the market congestion reports, the AER determined that the available data for the January to June 2003 period is not sufficiently reliable to use for calculating a performance target. However the AER expects that five years of reliable historical data will be available for future TNSP transmission determinations.

Regarding the issue raised by the EUAA, the incentive option was developed to promote the NEM objective and the efficient use of existing transmission infrastructure. The AER considered several option criteria as part of the incentive and concluded that the option should largely depend on the TNSP's action and that the information and analysis should be able to be audited. The historical data approach uses publicly available information for analysis which enables stakeholders to verify the measures produced. If the benchmark were to be set based on the current regulatory control period, speculative data would be generated which would not be as verifiable and reliable as that of past performance data.

TransGrid's proposal excluded degenerate solutions[432] from the performance target calculation. This is consistent with the market impact parameter definition set out in appendix C of the scheme as it states that the marginal value is an indication of the change in the cost of producing electricity.[433] The remaining outages excluded by TransGrid when calculating the performance target are consistent with the parameter definition in appendix C of the scheme.

Clause 4.2 (d) of the scheme provides that the data used to calculate the performance target must be consistently recorded and based on the parameter definitions set out in appendix C of the scheme. During the review process the AER discovered a further five degenerate solutions which, (under the parameter definition in appendix C of the scheme), should have been excluded when calculating TransGrid's performance

431 EUAA, p. 32.

432 Degeneracy occurs when there is more than one best solution in the solution space that derives the same outcome.

433 A degenerate solution produces a marginal value that is an outcome from the mathematics of the dispatch algorithm related to the constraint violation penalties and not the cost of producing electricity.

target. Given this and the requirements of clause 4.2(d) of the scheme, the AER rejects TransGrid's proposed performance target of 2858 dispatch intervals and substitutes a performance target of 2857 dispatch intervals to account for the five non excluded degenerate solutions.

8.8 AER conclusion

The definitions that apply to TransGrid for the next regulatory control period are set out in appendix B of the scheme. The performance incentive curves for each parameter are set out in appendix G of this draft decision.

TransGrid's caps, collars, performance targets and weightings for the service component of the scheme during the next regulatory control period are set out in table 8.8.

Table 8.8: Service component caps, collars, targets and weightings to apply to TransGrid

Parameter	Collar	Target	Cap	Weighting
Transmission circuit availability (%)				*MAR (%)*
Transmission line availability	99.05	99.26	99.36	0.20
Transformer availability	97.26	98.55	98.84	0.15
Reactive plant availability	98.65	99.12	99.33	0.10
Loss of supply event frequency (no.)				*MAR (%)*
> 0.05 (x) system minutes	7	4	2	0.25
> 0.25 (y) system minutes	2	1	0	0.10
Average outage duration (minutes)				*MAR (%)*
Total	999	824	649	0.20

TransGrid's target and cap for the market impact component of the scheme are set out in table 8.9.

Table 8.9: Market impact component target, cap and weighting to apply to TransGrid

Parameter	Values		
Market impact parameter	**Target**	**Cap**	**Weighting**
	Number of dispatch intervals with a marginal value greater than $10/MWh		*MAR (%)*
	2857	0	2.0

9 Maximum allowed revenue

9.1 Introduction

This chapter sets out the AER's calculation of TransGrid's maximum allowed revenue (MAR) for the provision of prescribed transmission services for each year of the next regulatory control period, using the building block approach.

9.2 Regulatory requirements

Clause 6A.2 of the NER requires the AER to make transmission determinations for TNSPs, in accordance with chapter 6A in respect of prescribed transmission services and negotiated transmission services. A revenue determination forms part of the AER's transmission determination.

Clause 6A.4.2(a) of the NER requires a revenue determination to specify, amongst other things:

> (1) the amount of the estimated total revenue cap for the regulatory control period or the method of calculating that amount;
>
> (2) the annual building block revenue requirement for each regulatory year of the regulatory control period;
>
> (3) the amount of the maximum allowed revenue for each regulatory year of the regulatory control period or the method of calculating that amount.

9.2.1 Annual building block revenue requirement

Clause 6A.5.4(a) outlines the calculation of the annual building block revenue requirement for each year of the regulatory control period, which comprises the following components:

> (1) indexation of the regulatory asset base - see paragraph (b)(1);
>
> (2) a return on capital for that year - see paragraph (b)(2);
>
> (3) the depreciation for that year - see paragraph (b)(3);
>
> (4) the estimated cost of corporate income tax of the provider for that year - see paragraph (b)(4);
>
> (5) certain revenue increments or decrements for that year arising from the efficiency benefit sharing scheme - see paragraph (b)(5);
>
> (6) the forecast operating expenditure accepted or substituted by the AER for that year – see paragraph (b)(6); and
>
> (7) compensation for other risks - see paragraph (b)(7).

9.2.2 Post-tax revenue model

Clause 6A.5.2 requires the AER to develop a post-tax revenue model (PTRM) to calculate the annual building block revenue requirement for each year of the regulatory control period using the approach described in clause 6A.5.4. A TNSP's

revenue proposal must be prepared using the PTRM. For the purposes of this draft decision, the NER provides that TransGrid must use the AER's PTRM, which was published in September 2007.

The PTRM estimates the MAR for each year of the regulatory control period by escalating the previous year's MAR using a CPI – X framework, based on the MAR that applies to the TNSP in the first year of the regulatory control period. The PTRM incorporates a forecast inflation rate to calculate the expected MAR, whereas the actual MAR is adjusted for actual inflation. This adjustment process is set out in section 9.3.

Clause 6A.6.8(c) requires the X factor for each year of the regulatory control period to be determined such that:

1. the net present value (NPV) of the expected MAR for each year of the regulatory control period is equal to the NPV of the annual building block revenue requirement for each year of the regulatory control period and
2. the expected MAR for the last year of the regulatory control period is as close as reasonably possible to the annual building block revenue requirement for that year.

The X factor for each year must be that nominated in the TNSP's revenue proposal, providing it complies with the above requirements. However, to the extent that the X factors nominated by the TNSP do not so comply, the X factor for each year will be those determined by the AER in its final decision.[434]

9.2.3 Adjustments to the revenue cap

The MAR is the revenue that a TNSP may earn in any year of the regulatory control period from the provision of prescribed transmission services. The MAR must be determined in accordance with part C of chapter 6A of the NER and the methodology set out in the revenue determination.

The AER may adjust the MAR for the following:

1. In accordance with clause 6A.7, adjust the revenue cap after making a revenue determination for:
   - reopening of the revenue determination for capex to respond to unforeseen circumstances
   - network support pass through
   - cost pass through
   - the service target performance incentive scheme applied to the TNSP.
2. In accordance with clause 6A.8, the inclusion of a contingent project.
3. In accordance with clause 6A.15, the revocation of a revenue determination or the amendment of a pricing methodology for wrong information or error.

[434] NER, clause 6A.6.8(b).

9.3 Determining the MAR—adjustments for performance incentive and pass through amounts

The annual building block revenue requirement can be lumpy over the regulatory control period. To minimise price shocks, revenues are smoothed within a regulatory control period while maintaining the principle of cost recovery under the building block approach. Smoothing requires diverting some of the cost recovery to adjacent years within the regulatory control period so that the NPV of the smoothed revenues is equal to the NPV of the annual building block revenue requirement (unsmoothed revenue stream). That is, a smoothed profile of the TNSP's MAR is determined for the regulatory control period under the CPI – X mechanism.

The MAR for the first year is generally set equal to the allowed revenue (AR) for the first year of the regulatory control period:

$$MAR_1 = AR_1$$

where:

MAR_1 = the maximum allowed revenue for year 1

AR_1 = the allowed revenue for year 1.

The MAR for the subsequent year of the regulatory control period requires an annual adjustment based on the previous year's AR. That is, the subsequent year's AR is determined by adjusting the previous year's AR for actual inflation and the X factor:

$$AR_t = AR_{t-1} \times (1 + \Delta CPI) \times (1 - X_t)$$

where:

AR = the allowed revenue

t = time period/financial year (for $t = 2, 3, 4, 5$)

ΔCPI = the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in year $t - 2$ to March in year $t - 1$

X = the smoothing factor.

The MAR is determined annually by adding to (or deducting from) the AR, the service target performance incentive scheme revenue increment (or revenue decrement) in accordance with 6A.7.4, and any approved pass through amounts in accordance with 6A.7.3 (see table 9.1 for the timing of calculating the AR and performance incentive):[435]

[435] As required under the NER, a TNSP must also adjust the MAR for under or over recovery amounts.

$$MAR_t = \text{(allowed revenue)} + \text{(performance incentive)} + \text{(pass through)}$$

$$= AR_t + \left(\frac{\left(AR_{t-1} + AR_{t-2} \right)}{2} \times S_{ct} \right) + P_t$$

where:

MAR = the maximum allowed revenue

AR = the allowed revenue

S = the revenue increment or decrement determined in accordance with the service target performance incentive scheme

P = the pass through amount that the AER has determined in accordance with clauses 6A.7.2 and 6A.7.3 of the NER

t = time period/financial year (for *t* = 2, 3, 4, 5)

ct = time period/calendar year (for *ct* = 2, 3, 4, 5).

Table 9.1: Timing of the calculation of allowed revenues and the performance incentive

t	Allowed revenue (financial year)	*ct*	Performance incentive (calendar year)
2	1 July 2010–30 June 2011	2	1 January 2009–31 December 2009
3	1 July 2011–30 June 2012	3	1 January 2010–31 December 2010
4	1 July 2012–30 June 2013	4	1 January 2011–31 December 2011
5	1 July 2013–30 June 2014	5	1 January 2012–31 December 2012

9.4 TransGrid proposal

TransGrid applied the post-tax building block approach to calculate its proposed revenues. It proposed that the calculation of the revenues be determined for a five-year regulatory control period.[436] TransGrid's proposed revenues were determined on the basis of a nominal opening RAB of $4237 million.[437] It proposed nominal unsmoothed revenues of $670 million in 2009–10, increasing to $938 million in 2013–14.[438] TransGrid's MAR for the final year of its current regulatory control period (2008–09) is $622 million. Table 9.2 summarises TransGrid's total proposed annual building block revenue requirement (unsmoothed) and the expected MAR for each year of the next regulatory control period.[439]

[436] TransGrid, *Revenue proposal*, p. 10.
[437] TransGrid, *Revenue proposal*, p. 109.
[438] TransGrid, *Revenue proposal*, p. 121.
[439] While the total value of the annual building block revenue requirement is different to the total value of the expected MAR (smoothed), the two are equivalent in NPV terms.

Table 9.2: TransGrid's proposed annual building block revenue requirement and maximum allowed revenue ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Return on capital	387.7	433.2	475.7	546.5	594.2	2437.5
Regulatory depreciation	79.6	81.9	74.7	84.5	96.0	416.6
Operating expenditure	179.3.	176.3	189.2	209.1	215.6	969.5
Opex efficiency carryover	6.3	3.5	4.1	3.9	–0.8	17.1
Net taxes payable	23.6	24.9	24.6	28.7	31.9	133.7
Annual building block revenue requirement (unsmoothed)	670.2	716.3	764.2	868.7	937.8	3957.2
Maximum allowed revenue (smoothed)	670.2	725.6	785.5	850.3	920.5	3952.1

Source: TransGrid, *Revenue proposal*, p. 120–21.

TransGrid has proposed to annually escalate its expected MAR over the next regulatory control period by applying X factors corresponding to –5.59 per cent for 2010–11 to 2013–14.[440]

TransGrid stated that its revenue proposal would result in an average annual increase in transmission charges of 3.9 per cent (real). As TransGrid's costs represent about 6 per cent of the total delivered price for the average energy user, the impact on the total delivered price is estimated to be about 0.25 per cent a year. This is expected to result in a price rise for the typical household in NSW of about $3.50 a year.[441]

9.5 AER assessment of building blocks

9.5.1 Opening asset base and roll forward

The NER requires that the roll forward of TransGrid's RAB, as at the end of each year of the next regulatory control period, be calculated by taking the opening RAB value, adjusting it for inflation, adding any additional capex, and subtracting disposals and depreciation for the year. The closing RAB value for one year then becomes the opening RAB value for the following year.

As discussed in chapter 2, the AER has determined the opening value of TransGrid's RAB to be $4234 million as at 1 July 2009. Based on this opening value, the AER has modelled TransGrid's RAB over the next regulatory control period as shown in table 9.3.

[440] TransGrid, *Revenue proposal*, p. 121.
[441] TransGrid, *Revenue proposal*, pp. 121–23.

Table 9.3: AER's roll forward of TransGrid's regulatory asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	4234.0	4726.4	5134.7	5680.4	6195.5
Net capital expenditure	564.3	480.9	610.2	588.6	441.9
Inflation adjustment on opening RAB	108.0	120.5	130.9	144.9	158.0
Straight-line depreciation	–179.9	–193.1	–195.5	–218.4	–240.7
Closing RAB	4726.4	5134.7	5680.4	6195.5	6554.7

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

9.5.2 Forecast capital expenditure

As discussed in chapter 3, the AER has determined a forecast capex allowance for TransGrid of $2376 million ($2007–08) during the next regulatory control period. In 2008–09 dollar terms the forecast capex allowance is $2443 million. The annual nominal allowance is shown in table 9.3 and is used to calculate the roll forward value of TransGrid's RAB.[442]

9.5.3 Weighted average cost of capital

The AER has determined the annual return on capital allowance by applying the weighted average cost of capital (WACC) to TransGrid's opening RAB for each year of the next regulatory control period.

As discussed in chapter 4, the nominal vanilla WACC of 9.82 per cent is based on a post-tax nominal return on equity of 11.46 per cent and a pre-tax nominal return on debt of 8.73 per cent. Table 9.5 shows the AER's return on capital allowance for this draft decision.

9.5.4 Operating expenditure

As discussed in chapter 5, the AER has determined a forecast opex allowance for TransGrid of $765 million ($2007–08) during the next regulatory control period. In 2008–09 dollar terms the forecast opex allowance is $805 million. Table 9.5 shows the annual opex allowance.

9.5.5 Operating expenditure efficiency allowance

As discussed in chapter 6, the AER has determined an opex efficiency allowance under the efficiency carry forward mechanism of $8.9 million ($2008–09) for TransGrid during the next regulatory control period. Table 9.5 shows the annual efficiency allowance.

[442] In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six month period before capex is added to the RAB for revenue modelling purposes.

9.5.6 Depreciation

As discussed in chapter 7 and using the post-tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight-line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the regulatory control period and to determine the depreciation allowance. Table 9.5 shows the resulting figures.

In modelling the applicable straight-line depreciation in the PTRM, the AER has based its calculations on the approved average remaining lives for existing assets standard lives for new assets (by asset classes).

9.5.7 Estimated taxes payable

Using the PTRM, the AER has modelled TransGrid's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this draft decision. The amount of tax payable is estimated using 60 per cent debt benchmark gearing, rather than TransGrid's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause 6A.6.4(a) of the NER, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Under the post-tax nominal framework, the application of the statutory tax rate generates an effective tax rate that can provide more appropriate and cost-reflective revenue outcomes. The effective tax rate is defined as the difference between pre-tax and post-tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Based on the approach to modelling the cash flows in the PTRM, the AER has derived an effective tax rate of 24.1 per cent for this draft decision. Table 9.4 shows the AER's estimate of TransGrid's tax payments.

Table 9.4: AER's modelling of net tax allowance ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Tax payable	45.1	47.4	46.1	52.1	58.1	248.7
Value of imputation credits	–22.5	–23.7	–23.0	–26.0	–29.0	–124.4
Net tax allowance	22.5	23.7	23.0	26.0	29.0	124.4

Note: Total may not add up due to rounding.

9.6 AER determination—maximum allowed revenue

9.6.1 Annual building block revenue requirement

Based on its assessment of the building block components and using the PTRM, the AER has determined an annual building block revenue requirement for TransGrid that increases from $678 million in 2009–10 to $904 million in 2013–14 ($nominal). Table 9.5 shows the annual building block calculations.

Table 9.5: AER's draft decision on annual building block revenue requirement ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Return on capital	415.9	464.2	504.3	557.9	608.5	2550.8
Regulatory depreciation	71.9	72.6	64.6	73.5	82.7	365.3
Opex allowance	163.5	158.8	167.2	181.4	188.6	859.5
Opex efficiency allowance[a]	4.6	3.4	4.5	1.1	–4.5	9.0
Net tax allowance	22.5	23.7	23.0	26.0	29.0	124.4
Annual building block revenue requirement (unsmoothed)	678.4	722.7	763.6	840.0	904.3	3909.0

(a) An allowance for opex efficiency resulting from the carry forward mechanism applied in the current regulatory control period.

9.6.2 Expected maximum allowed revenue—smoothed

The NPV of the annual building block revenue requirement for the next regulatory control period has been calculated to be $2937 million. Based on this NPV amount, the AER has determined a nominal expected MAR (smoothed) for TransGrid that increases from $678 million in 2009–10 to $891 million in 2013–14, as shown in table 9.6. The total revenue cap for TransGrid over the next regulatory control period is $3909 million. TransGrid's MAR for the next regulatory control period is to be calculated using the formula described in section 9.3.

To determine the expected MAR (smoothed) over the next regulatory control period the AER has set the first year MAR equal to the annual building block revenue requirement for that year and applied an X factor of –4.39 per cent in subsequent years, as shown in table 9.6. The AER considers that this profile of X factors results in an expected MAR in the final year of the regulatory control period that is not unreasonably different to the annual building block revenue requirement for that year, and is therefore in accordance with clause 6A.6.8(c)(2) of the NER.

Table 9.6: AER's draft decision on the maximum allowed revenue ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
MAR (smoothed)	678.4	726.3	777.5	832.4	891.1	3905.7
X factor (%)	n/a[a]	–4.39	–4.39	–4.39	–4.39	n/a

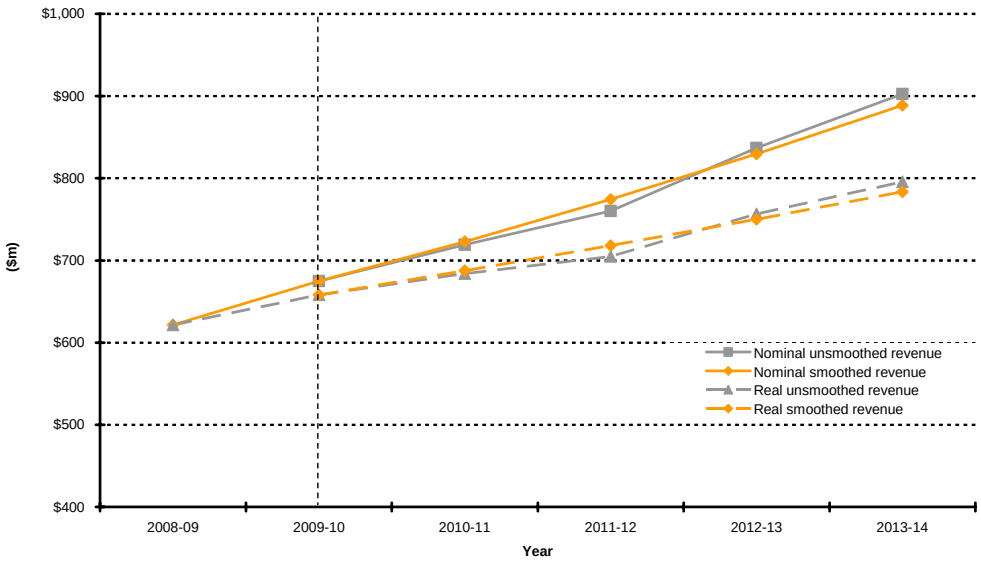
(a) The MAR for 2009–10 is set as $678.4 million and TransGrid is not required to apply an X factor. The MAR in the first year of the next regulatory control period (2009–10) is around 9.1 per cent higher than the MAR in the final year of the current regulatory control period (2008–09).

The average revenue increase of 7.5 per cent per annum (nominal) from 2008–09 to 2013–14 consists of an initial increase of 9.1 per cent from 2008–09 to 2009–10 and a subsequent average annual increase of 7.1 per cent during the remainder of the next regulatory control period.

In real terms ($2008–09), the average revenue increase of 4.8 per cent per annum from 2008–09 to 2013–14 consists of an initial increase of 6.4 per cent from 2008–09 to 2009–10 and a subsequent average annual increase of 4.4 per cent during the remainder of the next regulatory control period.

Figure 9.1 shows the revenue path allowed in this draft decision (both smoothed and unsmoothed) in nominal and real terms.

Figure 9.1: Revenue path from 2009–10 to 2013–14 ($m)



9.7 Average transmission charges

TransGrid's MAR for the next regulatory control period is established through a building block approach. While the AER assesses TransGrid's proposed pricing methodology, actual transmission charges established at particular connection points are not approved by the AER. TransGrid establishes its transmission charges in accordance with its approved pricing methodology and the NER.

The effect of the AER's draft decision on average transmission charges can be estimated by taking the annual MAR and dividing it by forecast annual energy delivered in NSW.[443] Based on this approach, the AER estimates that this draft decision will result in a 6.6 per cent per annum (nominal) increase in average transmission charges from 2008–09 to 2013–14 or an increase of 4.0 per cent per annum in real terms ($2008–09).

The increase in the average transmission charges is greater than the average growth in the level of peak demand in NSW, which is forecast to increase by 2.5 per cent per annum over the next regulatory control period.[444] The increase in average transmission charges is primarily because of:

[443] The forecast energy delivered (NSW scheduled energy supplied at connection points) figures were obtained from TransGrid, *Annual Planning Report*, June 2008, p. 88.

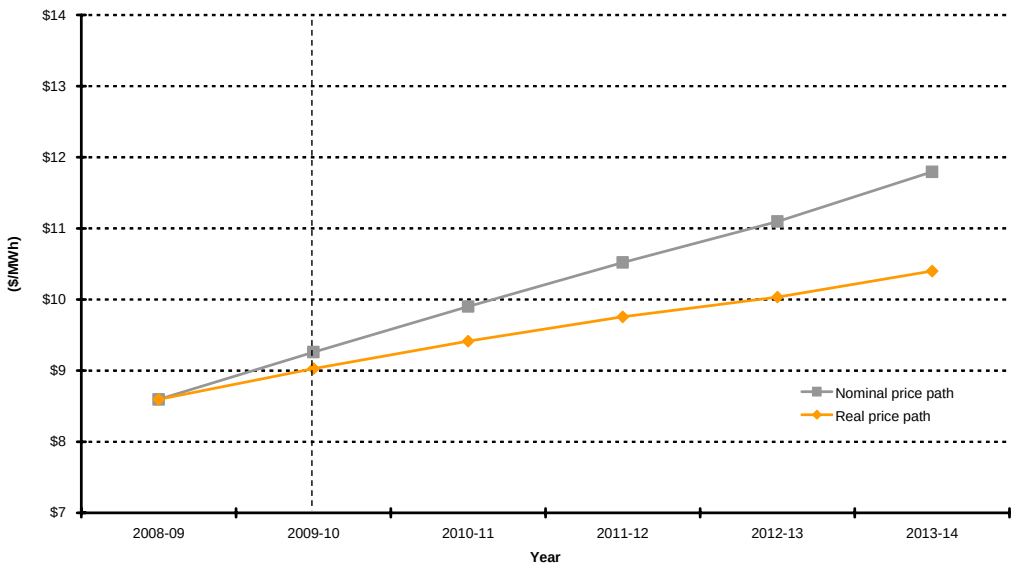
[444] TransGrid, *2008 APR*, p. 89.

- a higher WACC compared with that allowed for TransGrid during the current regulatory control period because of the increased cost of borrowing caused by a significant widening of the debt risk premium driven by the ongoing global credit crisis—increasing corporate bond yields
- a higher opening RAB than was forecast in the 2005 revenue cap decision
- the higher cost of replacing and maintaining assets
- the need for increased capex associated with maintaining reliability standards
- high input costs such as construction materials and labour (as a consequence of the commodity/minerals boom)
- increased opex due to a growing asset base.

Transmission charges represent approximately 6 per cent on average of end user electricity charges in NSW. The AER estimates that the increase in average transmission charges under this draft decision will add approximately $4.00 to the average residential customer's annual bill of $983 (0.4 per cent).[445]

Figure 9.2 shows the resulting average price path of this draft decision during the next regulatory control period compared with the average price for the final year of the current regulatory control period in nominal and real terms ($2008–09). The average transmission charges in 2008–09 is $8.59 per MWh. Nominal average transmission charges are forecast to increase from around $9.31 per MWh in 2009–10 to $11.83 per MWh in 2013–14. Real average transmission charges are forecast to increase from around $9.08 per MWh in 2009–10 to $10.43 per MWh in 2013–14.

Figure 9.2: Price path from 2009–10 to 2013–14 ($/MWh)



445 IPART, *Overview of final report and determination on electricity retail prices in NSW—From 1 July 2007 to 30 June 2010*. The average customer bill was calculated using 2008–09 data for medium residential usage and an average across the three standard retailers in NSW.

10 Negotiating framework for negotiated transmission services

10.1 Introduction

The AER is required to make a determination on TransGrid's proposed negotiating framework for the relevant regulatory control period, after assessing it in accordance with clause 6A.9 of the NER.

The negotiating framework should stipulate the procedure to be followed by the TNSP and the service applicant when negotiating the terms and conditions of access for negotiated transmission services. In accordance with chapter 6A part K, in the event of an access dispute a commercial arbitrator must have regard to the negotiating framework.

Service applicants can make an application and negotiate terms and conditions of access for three types of negotiated transmission services with a TNSP. These services include:

- connection services (which might include entry, exit and TNSP to market network service provider connection services)
- use of system services supplied by the shared transmission network that exceed or are below the networks specified performance standard under any legislation of a participating jurisdiction
- use of system services relating to an augmentation or extension required to be undertaken on a transmission network as described in clause 5.4A of the NER.[446]

The negotiating framework only relates to negotiated transmission services. The pricing of prescribed transmission services is covered by the pricing methodology discussed in chapter 12 of this draft decision.

10.2 Regulatory requirements

Clause 6A.2.2(2) of the NER states that a transmission determination made by the AER pursuant to clause 6A.2.1 must include a determination relating to the TNSP's negotiating framework.

10.2.1 TNSP proposal

In accordance with clause 6A.9.5(a) of the NER, a TNSP must prepare a negotiating framework setting out the procedure to be followed when negotiating terms and conditions of access for a negotiated transmission service. Consistent with clause 6A.10.1(b), the TNSP must submit its proposed negotiating framework to the AER when it submits its revenue proposal.

Clause 6A.9.5(b) of the NER requires that the TNSP's negotiating framework must comply with the applicable requirements of its transmission determination and the

[446] NER, Definition of 'Negotiated Transmission Service', chapter 10.

minimum requirements for a negotiating framework set out in clause 6A.9.5(c) of the NER.

Under clause 6A.10.1(c) of the NER, the proposed negotiating framework must comply with the requirements of, and must contain or be accompanied by, information required by the submission guidelines.

10.2.2 AER negotiating framework determination

The AER will assess the TNSP's proposed negotiating framework under clause 6A.9.5(c) of the NER, which states that a TNSP's negotiating framework must specify:

- a requirement that a TNSP and service applicant negotiate the terms and conditions of a negotiated transmission service in good faith
- a requirement for the TNSP and service applicant to provide all commercial information that will allow effective negotiation, subject to the confidential information provisions of clause 6A.9.6
- a requirement for the TNSP to provide a reasonable estimate of the costs of providing the negotiated transmission service and demonstrate that the charges reflect those costs, including any increases or decreases
- a reasonable time period for negotiation and a requirement for each party to use reasonable endeavours to adhere to the time period
- a process for dispute resolution that allows for all disputes in relation to terms and conditions of access to be dealt with in accordance with part K of chapter 6A of the NER
- arrangements for the payment of a TNSP's reasonable direct expenses incurred in processing the application
- a requirement that a TNSP determine the potential impact of the negotiated transmission service on other network users
- a requirement that the TNSP must notify and consult with any affected network user and ensure that the provision of the negotiated transmission service does not result in other network users non compliance with their obligations under the NER.

The AER must make a decision to approve, or refuse to approve, the TNSP's proposed negotiating framework and set out the reasons for its decision.[447] The AER's determination relating to the TNSP's negotiating framework must set out any requirements that are to be complied with in respect of the preparation, replacement, application or operation of the TNSP's negotiating framework.[448] If the AER's decision is to refuse to approve the TNSP's proposed negotiating framework in its final decision, it must include an amended negotiating framework in its final

[447] NER, clause 6A.14.1(6).
[448] NER, clause 6A.9.3.

transmission determination. Any amendments made by the AER must be based on the TNSP's proposed negotiating framework and amended only to the extent necessary to enable it to be approved in accordance with the NER.[449]

10.3 TransGrid proposal

TransGrid's negotiating framework stated that it applies to TransGrid and any service applicant who has made an application in writing for a negotiated transmission service. Any service applicant should apply and comply with the requirements of the negotiating framework. The requirements of the negotiating framework are additional to any requirements in chapters 4, 5 and 6A of the NER and if any inconsistencies exist, the requirements of the NER prevail.[450] The negotiating framework requires that both parties in a negotiating process to negotiate in good faith the terms and conditions of access for the negotiated transmission service.[451]

Where a negotiated transmission service is sought, the timeframes for commencing, progressing and finalising the negotiation and the commercial information required from TransGrid and the service applicant are set out in the negotiating framework.[452] The proposed timeframes can be modified with the agreement of both parties. The negotiating framework states that once an application is received from a service applicant both parties must use their reasonable endeavours to adhere to the proposed timeframes.[453]

The stated timeframes do not commence until the service applicant has paid the application fee. In addition, the timeframes can recommence if there is a material change in the negotiated transmission service sought.[454]

The negotiating framework states that both TransGrid and the service applicant, upon commencing negotiations for a negotiated transmission service, are obliged to provide all relevant commercial information to enable both parties to engage in effective negotiations. However, the commercial information that TransGrid and the service applicant receive from each other may be subject to certain conditions, including the condition that each party must treat the commercial information received from the other party as confidential unless both parties agree in writing to the disclosure.[455]

Further, the consent may be subject to a further condition that the person to whom the information is disclosed may enter into a separate confidentiality agreement with either party. The negotiating framework stated that TransGrid may issue a notice requesting that the service applicant provide additional commercial information. The service applicant must use reasonable endeavours to provide the information requested, which is subject to confidentiality requirements.[456]

---

449 NER, clause 6A.13.2(c).
450 TransGrid, *Proposed negotiating framework for provision of a negotiated transmission service, 1 July 2009 to 30 June 2014,* 30 May 2008, clause 1, p. 5.
451 TransGrid, *Negotiating framework*, clause 2, p. 5.
452 TransGrid, *Negotiating framework*, clause 3, pp. 5–7.
453 TransGrid, *Negotiating framework*, clause 3.4, p. 6.
454 TransGrid, *Negotiating framework*, clause 3.6, p. 7.
455 TransGrid, *Negotiating framework*, clauses 4–6, pp. 7–10.
456 TransGrid, *Negotiating framework*, clauses 4–6, pp. 7–10.

The proposed negotiating framework also contains the requirement that TransGrid provides a reasonable estimate of the costs of providing the negotiated transmission service and demonstrate that the charges reflect those costs, including any increases or decreases as part of the provision of this commercial information.[457]

The negotiating framework establishes a process for the payment of the costs TransGrid incurs as a result of processing the application for a negotiated transmission service.[458] The service applicant must pay an application fee prior to commencing negotiations. This fee is not specified in the negotiating framework. The application fee will be deducted from the reasonable costs incurred by TransGrid in processing the application for the negotiated transmission service. TransGrid may issue the service applicant with a notice setting out the reasonable costs incurred and requesting payment of amounts above the application fee. Within 20 business days, the service applicant is required to pay TransGrid any amount requested in the notice. Further, TransGrid may require the service applicant to enter into a binding agreement regarding the payment of ongoing costs.[459]

The negotiating framework provides for negotiating timeframes to be suspended as agreed by the parties or in certain circumstances.[460] It also stated that either party can terminate the negotiations. Where the service applicant terminates a negotiation, it must do so in writing. TransGrid may only terminate a negotiation in certain circumstances.[461]

The negotiating framework states that TransGrid should determine the potential impact of the negotiated transmission service on transmission network users. As a part of this process, TransGrid will notify and consult with any affected transmission network users and ensure that the negotiated transmission service does not result in non compliance with obligations relating to other transmission network users under the NER.[462]

The negotiating framework states that all disputes arising between parties, regarding terms and conditions of access for the negotiated transmission service are subject to part K of chapter 6A of the NER.[463]

10.4 Submissions

The AER did not receive any submissions on TransGrid's proposed negotiating framework.

10.5 Issues and AER considerations

The AER notes clause 6A.2.2 requires that a transmission determination includes, amongst other things:

457 TransGrid, *Negotiating framework*, clause 6.1, p. 9.
458 TransGrid, *Negotiating framework*, clause 10, pp. 11–12.
459 TransGrid, *Negotiating framework*, clause 10, pp. 11–12.
460 TransGrid, *Negotiating framework*, clause 8, pp. 10–11.
461 TransGrid, *Negotiating framework*, clause 11, p. 12.
462 TransGrid, *Negotiating framework*, clause 7, p. 10.
463 TransGrid, *Negotiating framework*, clause 9, p. 11.

- a determination relating to a TNSP's negotiating framework
- a determination that specifies the negotiated transmission service criteria that shall apply to a TNSP.

Clause 6A.9.3 requires the AER's determination relating to the negotiating framework to specify requirements that are to be complied with in respect of the preparation, replacement, application or operation of the TNSP's negotiating framework.

The AER considers that TransGrid has prepared its proposed negotiating framework in accordance with the requirements of clause 6A.9.5, and that the application or operation of the framework is also specified in accordance with clause 6A.9.5.

However, the NER does not explicitly address how or when a TNSP should replace its negotiating framework. In the absence of a specific rule, the AER considers that a TNSP's negotiating framework will apply for the duration of the regulatory control period to which the transmission determination relates.

The AER considers TransGrid's negotiating framework as submitted is compliant with clause 6A.9.5(c) of the NER.

10.6 AER determination

The AER has assessed TransGrid's negotiating framework and considers that the negotiating framework is compliant with clause 6A.9.5(c) of the NER. TransGrid's negotiating framework is set out in appendix H.

As required by clause 6A.14.3(f) of the NER, the AER approves TransGrid's negotiating framework for the next regulatory control period.

11 Negotiated transmission service criteria

11.1 Introduction

The NER requires that the AER include negotiated transmission service criteria (criteria) as a part of a TNSP's transmission determination. Section 10.1 of this draft decision describes negotiated transmission services. Unlike the other components of a transmission determination, TNSPs are not required to submit criteria to the AER.

The criteria must be applied by the TNSP in negotiating the terms and conditions of access, including the price and access charges for negotiated transmission services. The criteria must also be applied by a commercial arbitrator in resolving disputes relating to the terms and conditions of access and access charges for negotiated transmission services.

11.2 Regulatory requirements

Under clause 6A.2.2 of the NER, the AER is required to make a determination specifying the criteria that apply to a TNSP as part of its transmission determination for that TNSP. The AER's determination must set out the criteria to apply to a TNSP in negotiating the provision of negotiated transmission services, specifically:

- the terms and conditions of access for negotiated transmission services, including the prices that are to be charged
- access charges that are negotiated by the provider during that regulatory control period.

The criteria must also be applied by a commercial arbitrator to resolve disputes about negotiated transmission services, specifically:

- the terms and conditions of access for the negotiated transmission service, including the price that is to be charged for the provision of that service by the TNSP
- access charges that are to be paid to, or by the TNSP.

Clause 6A.9.4(b) of the NER requires that the criteria must give effect to, and be consistent with, the negotiated transmission service principles specified in clause 6A.9.1.

In accordance with clause 6A.11.3 of the NER, the AER published its proposed criteria for TransGrid, and TransGrid's revenue proposal, proposed negotiating framework, proposed pricing methodology and supplementary information in June 2008.

11.3 Submissions

The AER did not receive any submissions on the proposed criteria for TransGrid.

11.4 Issues and AER considerations

The AER notes that the provisions of chapter 6A create a regime for the regulation of negotiated transmission services that is intended to be less intrusive than that applying to prescribed transmission services. In deciding on the negotiate/arbitrate framework the AEMC considered that there are fewer market failure concerns surrounding negotiated transmission services and that users of these services are likely to be large and well resourced, possessing countervailing market power enabling them to negotiate effectively.

As such, these services are not subject to the direct revenue control applied to prescribed transmission services in revenue determinations. Instead, prices and conditions for negotiated transmission services are intended to be agreed through commercial negotiation or, failing agreement, determined through commercial arbitration.

The AER notes that no submissions were received on the proposed criteria for TransGrid and therefore considers that the draft negotiated transmission service criteria released for consultation in June 2008 should remain unamended.

11.5 AER determination

As required by clause 6A.9.4 of the NER, the determination by the AER at appendix I specifies the negotiated transmission service criteria for TransGrid for the next regulatory control period.

12 Pricing methodology

12.1 Introduction

This chapter sets out the AER's consideration of TransGrid's proposed pricing methodology for the regulatory control period 1 July 2009 to 30 June 2014. In accordance with the NER, TransGrid has been appointed the co-ordinating network service provider for NSW by EnergyAustralia, Country Energy and Directlink Transmission Company (Directlink). As the co-ordinating network service provider for NSW, TransGrid is responsible for allocation of the aggregate annual revenue requirement for the provision of transmission services in NSW and calculating transmission prices.

12.2 Regulatory requirements

12.2.1 NER requirements

Clause 6A.24.1(b) of the NER defines a pricing methodology in terms of the pricing principles as set out in clause 6A.23 of the NER:

> A pricing methodology is a methodology, formula, process or approach that, when applied by a Transmission Network Service Provider:
>
> (1) allocates the aggregate annual revenue requirement for prescribed transmission services provided by that provider to:
>
> (i) the categories of prescribed transmission services for that provider; and
>
> (ii) transmission network connection points of Transmission Network Users; and
>
> (2) determines the structure of the prices that a Transmission Network Service Provider may charge for each of the categories of prescribed transmission services for that provider.

In accordance with clause 6A.10.1(e) of the NER, TransGrid's proposed pricing methodology must:

> (1) give effect to and be consistent with the Pricing Principles for Prescribed Transmission Services; and
>
> (2) comply with the requirements of, and contain or be accompanied by such information as is required by, the pricing methodology guidelines made for that purpose under rule 6A.25.

Clause 6A.14.3(g) of the NER states that the AER must approve TransGrid's proposed pricing methodology if it is satisfied that the methodology:

> (1) gives effect to and is consistent with the Pricing Principles for Prescribed Transmission Services; and
>
> (2) complies with the requirements of the pricing methodology guidelines.

12.2.2 Pricing methodology guidelines

The AER's pricing methodology guidelines (the guidelines)[464] were developed in accordance with clause 6A.25.1(a) of the NER.

The guidelines specify or clarify:

(a) the information that is to accompany a proposed pricing methodology;

(b) permitted pricing structures for the recovery of the locational component of providing prescribed TUOS services;

(c) permitted postage stamp pricing structures for prescribed common transmission services and the recovery of the adjusted non-locational component of providing prescribed TUOS services;

(d) the types of transmission system assets that are directly attributable to each category of prescribed transmission services; and

(e) those parts of a proposed pricing methodology, or the information accompanying it that will not be publicly disclosed without the consent of the TNSP.

12.3 TransGrid proposal

On 31 May 2008 TransGrid submitted its proposed pricing methodology for the next regulatory control period to the AER.[465] TransGrid stated that its proposed pricing methodology complies with the requirements of chapter 6A of the NER and the guidelines.

TransGrid's proposed pricing methodology outlines:

- its obligation as the co-ordinating network service provider for NSW
- the calculation of the aggregate annual revenue requirement (AARR)
- allocation of the AARR to categories of prescribed transmission services to derive the annual service revenue requirement (ASRR) for each category of prescribed transmission service
- allocation of the ASRR for each category of prescribed transmission service to connection points
- a description of the derivation of prices and charges for each category of prescribed transmission service including the calculation of any excess demand charge
- a description of billing arrangements, prudential requirements, prudent discounts and TransGrid's proposed approach to monitoring and compliance of its approved pricing methodology
- a description of the key differences between the proposed pricing methodology and the pricing methodology applied in the current regulatory control period

[464] AER, *Electricity transmission network service provider—pricing methodology guidelines*, October 2007.

[465] TransGrid, *Proposed pricing methodology 1 July 2009 to 30 June 2014*, May 2008.

- hypothetical worked examples required to comply with the information requirements of the guidelines.

12.4 Submissions

The AER received two submissions on TransGrid's proposed pricing methodology.

The Energy Markets Reform Forum (EMRF) noted that TransGrid has elected to calculate its postage stamped prices using both historical energy and capacity, and the price that results in the lower estimated charge will be used. The EMRF considered this approach may be contrary to a pricing methodology based on long–run marginal cost.[466]

The EMRF considered that where transmission assets are attributable to more than one category of prescribed transmission service TransGrid should provide more details on its approach to cost allocation.[467]

The EMRF also stated that TransGrid has not identified the points in the network where costs will be allocated and prices determined. It considered the most appropriate points are the connection points where entry and exit assets interface with the assets that comprise the shared network.[468]

The EMRF disagreed with TransGrid's use of data from the most recent financial year in calculating locational TUOS prices. Further it noted that the guidelines provide a choice of two locational pricing structures to be included in TransGrid's proposed pricing methodology. It stated that while transmission customers have a choice as to the postage stamp pricing structure to calculate the non-locational prescribed TUOS service and prescribed common transmission service prices, no choice is afforded to customers for the locational price structure.[469]

Norske Skog noted the impact of network support pass throughs in early 2008 on transmission prices and charges. It stated that cost recovery of pass though events should be reflected in transmission usage charges, not common service and general charges.[470]

12.5 Issues and AER considerations

The pricing principles for prescribed transmission services (the pricing principles) outline the high level principles for the development of transmission prices while the guidelines supplement the pricing principles. The guidelines also outline the information that TransGrid is required to provide in its proposed pricing methodology. In assessing TransGrid's proposed pricing methodology, the AER has considered whether it gives effect to and is consistent with the pricing principles and whether it complies with the requirements of the guidelines.

466 EMRF, pp. 28–29.
467 EMRF, p. 29.
468 EMRF, p. 30.
469 EMRF, pp. 30–31.
470 Norske Skog, p 4.

This section outlines the AER's assessment of TransGrid's proposed pricing methodology against the pricing principles and the guidelines.

12.5.1 Determination of the AARR and its allocation to categories of prescribed transmission services

TransGrid proposal

TransGrid stated that it is the co-ordinating network service provider for NSW and therefore collects regulated revenue entitlements for itself, EnergyAustralia's prescribed transmission services, Country Energy and Directlink. It noted EnergyAustralia, Country Energy and Directlink's obligation to provide it with sufficient information for it to ensure the proper calculation of prescribed transmission prices within NSW.[471]

TransGrid is required to calculate the AARR in accordance with clause 6A.22.1 of the NER. Section 6.3 of TransGrid's proposed pricing methodology outlines how the AARR will be determined and states that the operating and maintenance costs expected to be incurred in the provision of prescribed common transmission services will be derived from budget projections.[472] These costs are subtracted from the maximum allowed revenue and recovered via prescribed common service prices and charges (as outlined in section 6.10 of TransGrid's proposed pricing methodology).

TransGrid stated the AARR would be allocated to the following categories of prescribed transmission services:

- prescribed entry services
- prescribed exit services
- prescribed common transmission services
- prescribed TUOS services.

The principles for allocating the AARR to categories of prescribed transmission services are outlined in clause 6A.23.2 of the NER. TransGrid noted it must also comply with the information requirements outlined in section 2.1(d) of the guidelines.

TransGrid provided a description of each category of prescribed transmission services. It noted that section 2.4 of the guidelines outline the types of transmission assets that are attributable to each category of prescribed transmission services.[473] In accordance with clause 6A.22.3 of the NER, TransGrid proposed to use the attributable cost share, calculated using the optimised replacement cost to allocate asset costs to each category of prescribed transmission services. Sections 6.6 and 6.7 of TransGrid's proposed pricing methodology show a hypothetical example of the allocation of the AARR to the categories of prescribed transmission services.[474]

Any asset that may be attributable to more than one category of prescribed transmission services is subject to the priority ordering approach outlined in clause 6A.23.2(d) of the NER. Clause 6A.23.2(d) states:

---

471 TransGrid, *Proposed pricing methodology*, pp. 1, 4.
472 TransGrid, *Proposed pricing methodology*, p. 4.
473 TransGrid, *Proposed pricing methodology*, p. 5.
474 TransGrid, *Proposed pricing methodology*, pp. 6–7.

> Where, as a result of the application of the attributable cost share, a portion of the AARR would be attributable to more than one category of prescribed transmission services, that attributable cost share is to be adjusted and applied such that any costs of a transmission system asset that would otherwise be attributed to the provision of more than one category of prescribed transmission services, is allocated as follows:
>
> (1) to the provision of prescribed TUOS services, but only to the extent of the stand-alone amount for that category of prescribed transmission services;
>
> (2) if any portion of the costs of a transmission system asset is not allocated to prescribed TUOS services, under subparagraph (1), that portion is to be allocated to prescribed common transmission services, but only to the extent of the stand-alone amount for that category of prescribed transmission services;
>
> (3) if any portion of the costs of a transmission system asset is not attributed to prescribed transmission services under subparagraphs (1) and (2), that portion is to be attributed to prescribed entry services and prescribed exit services.

Appendix C of TransGrid's proposed pricing methodology outlines its proposed priority ordering approach, as required under section 2.1(d)(2) of the guidelines. TransGrid relies on an assumption that substation infrastructure and establishment costs are proportionate to the number of high voltage circuit breakers in the substation. Based on this assumption, it allocates substation infrastructure and establishment costs based on the ratio of the number of high voltage circuit breakers in the stand alone arrangement to the number of high voltage circuit breakers in the substation.[475] Costs will be allocated to prescribed TUOS services based on the number of circuit breakers that would be required if the substation were built to provide prescribed TUOS services only. The remaining costs will next be allocated to prescribed common transmission services based on the number of circuit breakers that would be required had the substation been built solely for that purpose. Any remaining costs are finally allocated to prescribed entry and/or prescribed exit services in accordance with TransGrid's cost allocation process.[476]

Section 2.1(d)(3) of the guidelines requires TransGrid to provide details of how asset costs that may be attributable to both prescribed entry services and prescribed exit services will be allocated. TransGrid noted:[477]

> In the case of a shared connection asset (such as a transformer) serving multiple transmission connection points, which may provide both prescribed entry services and prescribed exit services, the cost of the shared connection asset will be allocated to the appropriate category or categories of prescribed transmission services using an appropriate causal cost allocator.

TransGrid also noted that, at the time of drafting its proposed pricing methodology, it did not have any connection points which provide both generator entry and customer exit services to different customers.[478]

---

475 TransGrid, *Proposed pricing methodology*, Appendix C, p. 29.
476 TransGrid, *Proposed pricing methodology*, Appendix C, p. 31.
477 TransGrid, *Proposed pricing methodology*, p. 6.
478 TransGrid, *Proposed pricing methodology*, p. 6.

Submissions

The EMRF noted that TransGrid is required to provide details of how assets that may be allocated to both entry and exit services will be allocated. It noted that TransGrid proposed to allocate costs using an appropriate causal cost allocator and considered that TransGrid should provide details of the causal allocator.[479]

AER considerations

The AER reviewed TransGrid's proposed arrangements regarding its role as a coordinating network service provider and for the determination and allocation of the AARR.

The AER considers that:

- the information TransGrid provided is sufficient to comply with the information requirements of section 2.1(a)–(b) of the guidelines
- TransGrid's proposed calculation of its AARR complies with the NER and that it has provided sufficient information to comply with section 2.1(c) of the guidelines
- TransGrid's proposed priority ordering approach is consistent with the requirements outlined in the pricing principles and the explanation in appendix E complies with the information requirements outlined in section 2.1(d)(2) of the guidelines.

The AER sought clarification from TransGrid on the causal cost allocator to be used where a connection asset provides both prescribed entry and prescribed exit services. In its response to the AER, TransGrid stated:[480]

> TransGrid's approach to connecting both entry and exit customers using common connection assets is to pro-rata the costs based on the MW capacity available to each customer. A pro-rata of costs based on energy is not useful as generator customers only pay for connection costs and do not pay any energy consumption costs. i.e. no payments for usage or postage stamp energy charges under the rules unless this is mutually negotiated.

The AER considers TransGrid's response provides sufficient clarification on the allocation of costs to shared connection assets providing both prescribed entry and prescribed exit services and the additional details should be included in TransGrid's final approved pricing methodology.

The AER is satisfied that TransGrid's proposed approach to calculating its AARR and its allocation of the AARR to categories of prescribed transmission services complies with clause 6A.23.2 of the NER and section 2.1(d) of the guidelines.

---

479 EMRF, p. 29.
480 TransGrid, response to AER information request, 3 September 2008.

12.5.2 Allocation of the ASRR to transmission network connection points

TransGrid proposal

Section 6.8 of TransGrid's proposed pricing methodology outlines its approach to allocating the ASRR for prescribed entry services, prescribed exit services and prescribed TUOS services to each transmission network connection point in accordance with clause 6A.23.3 of the NER. The allocation of the ASRR for prescribed common transmission services to connection points is conducted when prices and charges are determined.

TransGrid proposed to allocate the ASRR for prescribed entry services and prescribed exit services to transmission network connection points in accordance with the attributable connection point cost share for prescribed entry and exit services provided by the TNSP at each connection point.[481] TransGrid provided hypothetical worked examples of the allocation process in tables 4–7.[482]

Section 6.8.3 of TransGrid's proposed pricing methodology deals with how it intends to recover the ASRR allocated to prescribed TUOS services. Consistent with clause 6A.23.3(c)(1) of the NER, TransGrid proposed that the ASRR for the locational component of prescribed TUOS services be adjusted for estimated inter-regional settlements residue proceeds and used as an input for the cost reflective network pricing (CRNP) methodology.[483] CRNP methodology allocates the adjusted share of the ASRR to connection points on the basis of estimated proportionate use of transmission network assets by each transmission customer. The remainder of the ASRR to be collected through prescribed non-locational TUOS services is to be adjusted in the manner described in clause 6A.23.3(c)(2) of the NER.[484]

AER considerations

The AER has reviewed TransGrid's proposed pricing methodology in regard to the allocation of the ASRR.

The AER considers the information provided by TransGrid in relation to the allocation of the ASRR for prescribed entry services and prescribed exit services is sufficient to comply with section 2.1(e)(1)A of the guidelines and the hypothetical examples satisfy section 2.1(e)(1)B of the guidelines. Further, TransGrid's proposed calculation of the attributable connection point cost share is consistent with clause 6A.22.4 of the NER.

The AER is satisfied that the information provided by TransGrid regarding the recovery of the portion of the ASRR allocated to prescribed TUOS services complies with the NER and meets the information requirements of sections 2.1(e)(2)–(3) of the guidelines.

The AER is also satisfied that TransGrid's proposed approach to the allocation of the ASRR to connection points complies with clause 6A.23.3 of the NER and provides

---

481 TransGrid, *Proposed pricing methodology*, pp. 8–9.
482 TransGrid, *Proposed pricing methodology*, pp. 8–9.
483 TransGrid, *Proposed pricing methodology*, p. 10.
484 TransGrid, *Proposed pricing methodology*, p. 11.

sufficient information to comply with the requirements of sections 2.1(e)(2)–(3) of the guidelines.

12.5.3 Price structures

TransGrid proposal

Section 6.9 of TransGrid's proposed pricing methodology outlines its pricing structures and methodology for determining charges.

TransGrid proposed to recover the ASRR for prescribed entry and prescribed exit services via a fixed annual charge for each entry and exit point using a fixed $/day entry and exit price.[485]

TransGrid proposed to determine its locational prices and charges in the next regulatory control period using the same method as it currently uses to calculate its usage prices under the old NER.[486] The CRNP methodology determines the lump sum dollar amount to be recovered at each connection point. Once the amount to be recovered is known, TransGrid proposed:[487]

> … the annual locational charge allocated to each connection point is divided, with half assigned to the peak and shoulder energy charge and half assigned to the maximum monthly demand.
>
> To calculate rates, TransGrid adopts the level and pattern of usage that is the same as in the previous financial year. Accordingly, rates for each charge are calculated as follows:
>
> - Energy charge – divide the amount by the total energy usage during the previous financial year during the peak and shoulder demand period at that connection point (with adjustment for forecast system load growth from the historical period to the period during which the prices will apply) and express the result as a rate in cents/kWh.
>
> - Maximum demand charge – divide the amount by the average of the monthly maximum demands in each month at that connection point in the previous financial year (with adjustment for forecast system load growth from the historical period to the period during which the prices will apply) and express the result as a rate in $/kW/month.

The peak and shoulder period referred to span from 07:00 to 22:00 on working weekdays.[488]

TransGrid noted that its proposed locational pricing structure was not consistent with the two structures outlined in the guidelines however it stated that it considered it complied with clause 2.2(e) of the guidelines.[489]

The guidelines specify the permitted postage stamp pricing structures that can be used to determine prices for the non-locational component of prescribed TUOS services and prescribed common transmission services. TransGrid has elected to use the

[485] TransGrid, *Proposed pricing methodology*, p. 12.
[486] TransGrid, *Proposed pricing methodology*, p. 12.
[487] TransGrid, *Proposed pricing methodology*, p. 13.
[488] TransGrid, *Proposed pricing methodology*, p. 13.
[489] TransGrid, *Proposed pricing methodology*, p. 13.

structure outlined in section 2.3(c) of the guidelines which requires it to determine two prices at each connection point—one based on the contract agreed maximum demand and another based on historical energy. The price to be applied will be the one that results in the lowest estimated charge for each category of service.[490]

TransGrid proposed to add the costs expected to be incurred in the provision of prescribed common transmission services that are removed from the MAR prior to calculating the AARR, to the ASRR for prescribed common transmission services. This amount will be recovered via prescribed common transmission prices.

Section 2.3(c)(7)B of the guidelines requires TransGrid to specify penalties for exceeding the contract agreed maximum demand if it is to be used to calculate postage stamped prices. TransGrid's excess demand charge is set out in formal agreements with its customers and may differ between customers. The calculation of TransGrid's excess demand charge is outlined in section 6.11 of its proposed pricing methodology.

Submissions

The EMRF noted that TransGrid has elected to calculate its postage stamped prices using both historical energy and capacity, and the price that results in the lower estimated charge will be used. The EMRF considered this approach may be contrary to a pricing methodology based on long–run marginal cost.[491]

The EMRF also stated that TransGrid has not identified the points in the network where costs will be allocated and prices determined. It considered the most appropriate points are the connection points where entry and exit assets interface with the assets that comprise the shared network.[492]

The EMRF disagreed with TransGrid's use of data from the most recent complete financial year in calculating locational TUOS prices. It considered that the most recent 12 months should be used instead. Further it noted that the guidelines provide a choice of two locational pricing structures to be included in TransGrid's proposed pricing methodology. It stated that while transmission customers have a choice as to the postage stamp pricing structure to calculate the non-locational prescribed TUOS service and prescribed common transmission service prices, no choice is afforded to customers for the locational price structure.[493]

Norske Skog noted the impact of network support pass throughs in early 2008 on transmission prices and charges. It stated TransGrid has identified a number of pass through events for which it will seek to pass costs through to customers, effectively transferring all the risks of its business and decisions to its customers. This creates an on-going price uncertainty for the next five years. It stated that cost recovery of pass though events should be reflected in transmission usage charges not common service and general charges.[494]

---

490 TransGrid, *Proposed pricing methodology*, p. 15.
491 EMRF, p. 28.
492 EMRF, p. 30.
493 EMRF, pp. 30–31.
494 Norske Skog, p 4.

AER considerations

The AER has reviewed TransGrid's proposed pricing methodology and assessed its compliance with the requirements of the NER and the guidelines.

The AER considers TransGrid's proposed approach to calculating prescribed entry and prescribed exit service prices complies with clause 6A.23.4(c) of the NER and it has provided sufficient information to comply with section 2.1(f)(2) of the guidelines.

The AER considers the proposed postage stamp pricing structures comply with the pricing principles outlined in clause 6A.23 of the NER and section 2.3 of the guidelines. Additionally, TransGrid has complied with the information requirements outlined in sections 2.1(f)(4) and 2.1(f)(5).

Clause 2.2 of the guidelines specifies two permitted pricing structures for the recovery of the locational component of prescribed TUOS services. The AER also provided the opportunity for TNSPs to propose alternative structures, clause 2.2(d) of the guidelines states:

> A TNSP (or Co-ordinating Network Service Provider) may propose alternative pricing structures for the recovery of the locational component of prescribed TUOS services which it considers give effect to, and are consistent with the pricing principles for prescribed transmission services in the National Electricity Rules.

In proposing an alternative locational structure, clause 2.2(e) of the guidelines states:

> If a TNSP (or Co-ordinating Network Service Provider) proposes an alternative pricing structure for the recovery of the locational component of prescribed TUOS services it must clearly demonstrate to the AER that the alternative pricing structure:
>
> (1) gives effect to, and is consistent with the pricing principles for prescribed transmission services in the National Electricity Rules;
>
> (2) improves on the permitted pricing structures outlined in section 2.2(c) of these guidelines; and
>
> (3) contributes to the NEM objective.

TransGrid has proposed an energy price and charge and a maximum monthly demand price and charge to recover the locational component of prescribed TUOS services. Clause 6A.23.4(e) of the NER states:

> Prices for recovering the locational component of providing prescribed TUOS services must be based on demand at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated.

TransGrid stated that its proposed use of an energy price and charge is consistent with clause 6A.23.4(e) as the energy charge is a measure of average demand during peak and shoulder periods.[495] In considering this statement, the AER has referred to the AEMC's pricing rule determination which contains guidance as to its intent in

[495] TransGrid, *Proposed pricing methodology*, pp. 19–20.

drafting the pricing rule. The rule determination does not have the binding effect of the NER, but in most states of Australia extrinsic material, such as the rule determination, may be used in certain circumstances as an aid to interpretation.

In considering locational price structure principles, the AEMC's rule determination stated:[496]

> In respect of those prices intended to send locational investment or network usage signals, the Commission agrees that it makes sense for prices to be based on a transmission customer's demand at times of peak system demand. This is because it is network loading during peak system conditions that drives TNSPs to contemplate transmission investment to satisfy reliability criteria or enhance net market benefits. In this regard, the Draft Rule required prices for the locational TUoS charge to be based on "demand or consumption at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated." The Commission took this path in recognition of the fact that most TNSPs already base their TUoS locational prices (currently, the TUoS Usage prices) on either or both of demand or consumption at high-demand times.
>
> The Commission has been persuaded, however, that the Rules should be explicit that pricing for the locational TUoS charge should be based on demand (rather than consumption) of times of peak system conditions. The Commission considers that demand provides a better and clearer signal to users of the network. Therefore, the Final Pricing Rule has been amended to reflect this position.

The AER notes that under the old pricing rule, demand based, energy based and/or fixed prices and charges were permitted. When referring to the old pricing rule, the AEMC refers to energy based prices as consumption. It also appears to distinguish between demand and consumption indicating a preference for demand over consumption for the locational pricing structure under the new pricing rule.

The AER considers that the rule determination sought to exclude the use of energy based prices for the locational price structure. Additionally, clause 6A.23.4(e) refers to demand for which network investment is most likely to be contemplated. The AER considers network investment is more likely to be contemplated for peak demand rather than energy which is an average of demand.

Accordingly the AER has decided not to approve TransGrid's proposed locational price structure.

The AER notes the concern of the EMRF in relation to the use of the most recent financial year or the most recent 12 months. Clause S6A.3.2(3) of the NER refers to the CRNP methodology and specifies that the allocation of dispatched generation to load over a range of actual operating periods is to be from the previous financial year. The AER has no flexibility to alter this time period.

The guidelines specify two permitted locational pricing structures that a TNSP may apply and provide the opportunity for a TNSP to propose an alternative structure that

---

[496] AEMC, *Rule Determination, National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22*, 21 December 2006, p. 44.

complies with the NER.[497] The EMRF has stated that transmission customers should be provided with a choice of structure. However, the guidelines provide for the use of one structure not a combination of two or more structures.

The AER notes the EMRF's concern that TransGrid has not stated the points in the transmission network where costs will be allocated and prices calculated. The process of allocating costs first to each category of prescribed transmission services (to determine the ASRR for each category) and then allocating the ASRR to connection points indicates that costs will be allocated to connection points. Clause 6A.23.4(a) of the NER states that separate prices must be developed for the recovery of the ASRR and given the ASRR is allocated to connection points it is implicit that prices will be calculated at connection points. While neither the pricing principles nor the guidelines require a statement outlining the point in the network where costs will be calculated and prices determined, the AER considers TransGrid could, in order to remove any doubt, confirm the location of this point.

The EMRF raised concerns that the approach to recovering non-locational TUOS service and prescribed common service costs, proposed by TransGrid and specified in the guidelines, does not reflect long–run marginal costs as required by the AEMC. The AER notes that under clauses 6A.23.4(d) and 6A.23.4(j) of the NER prices for the non-locational component of prescribed TUOS services and prescribed common transmission services must be postage stamped. Postage stamping is a system of charging whereby the price per unit is the same regardless of how much energy is used or the location on the transmission network. Therefore it is conceivable that a user located close to a generator will pay the same price as a user located at the end of a long radial line. Under these circumstances, postage stamp prices and charges recover fixed costs in the least distortionary manner and are not necessarily intended to reflect long–run marginal costs in the same way as locational prices.[498]

The AER notes the concern of Norske Skog in relation to the price uncertainty created by pass through events. The NER provides for cost pass through of positive and negative amounts for TNSPs, where the costs are considered to be outside the control of the TNSP. Cost pass throughs are submitted to the AER and the AER must determine the approved pass through amount and the amount to be passed through in each year of the regulatory control period. The pass through amount for each year is added to the MAR to determine the AARR which is recovered via the TNSP's transmission prices and charges. Under the cost allocation arrangements all categories of transmission charges may be impacted by pass through amounts. However, as network support pass through amounts are generally not allocated to a specific asset, these charges are recovered through the non-locational component of transmission charges. As noted by Norse Skog this may mean that customers who are not direct beneficiaries of network support will contribute to the cost of the network support. The AER considers that network support is appropriately treated as an underlying cost of operating the network, and in the transmission network pricing arrangements such costs are appropriately treated as fixed costs and recovered through non-locational charges.

---

497 The guidelines also provide for TNSPs to propose alternative locational pricing structures that comply with the NER.

498 For detailed discussion on the economic principles of electricity transmission prices see: AER, *Pricing methodology guidelines*, pp. 4–10.

12.5.4 Additional information

TransGrid proposal

The guidelines require TNSPs to provide additional information to demonstrate consistency with part J of chapter 6A of the NER.

TransGrid has provided details of its approach to billing arrangements prescribed under clause 6A.27 of the NER.

TransGrid also provided details of prudential requirement arrangements permitted under clause 6A.28 of the NER. It stated that no capital contributions or prepayments have been made in respect of prescribed assets, however, if those payments are made in the future, they will be taken into account when calculating charges.

TransGrid stated that it has a small number of customers receiving prudent discounts which have been subject to previous approval processes. It was not aware of any new applications for prudent discounts.

TransGrid provided details of how it intends to monitor and develop records of its compliance with its approved pricing methodology, the pricing principles and part J of the NER. TransGrid stated:[499]

> In order to monitor and maintain records of its compliance with its approved pricing methodology, the pricing principles for prescribed transmission services, and part J of the Rules, TransGrid proposes to:
>
> - Maintain the specific obligations arising from part J of the Rules in its compliance management system;
> - Maintain electronic records of the annual calculation of prescribed transmission service prices and supporting information; and
> - Periodically subject its transmission pricing models and processes to functional audit by suitably qualified persons.

TransGrid stated that its existing pricing methodology is largely the same as its proposed pricing methodology for the next regulatory control period.[500] It noted the introduction of the priority ordering approach outlined in clause 6A.23.2(d) of the NER will result in immaterial reallocation of charges between categories of prescribed transmission services. TransGrid also noted the 2 per cent side constraint for locational prices may be relaxed subject to AER approval in accordance with 6A.23.4(g) of the NER.[501]

TransGrid noted several information requirements specified in the guidelines do not apply to it. It stated:[502]

- transitional arrangements are not required as a result of the implementation of its proposed pricing methodology

[499] TransGrid, *Proposed pricing methodology*, p. 22.
[500] TransGrid, *Proposed pricing methodology*, pp. 22–23.
[501] TransGrid, *Proposed pricing methodology*, p. 23.
[502] TransGrid, *Proposed pricing methodology*, p. 13.

- that apart from the provisions relating to Power Supply Agreements, chapter 9 derogations do not apply to TransGrid.

TransGrid did not provide a confidential version of its proposed pricing methodology as provided for under section 2.5 of the guidelines and therefore it is not required to provide information under section 2.1(n) of the guidelines.

AER considerations

The AER has reviewed TransGrid's proposed pricing methodology to assess its compliance with the information requirements of the guidelines.

The AER considers the information provided by TransGrid regarding its proposed approach to: billing arrangements; prudential requirements; prudent discounts; monitoring of compliance with and record keeping on its approved pricing methodology; and the differences between its current pricing methodology and its proposed pricing methodology are sufficient to satisfy the requirements of the guidelines.

Clause 11.8.5 of the NER relates to prudent discounts under existing agreements. Clause 11.8.5(c) states that the AER is not required to re-approve discounts that were approved prior to 28 December 2006 and any approval for the recovery of discounts identified in clauses 11.8.5(a) and (b) is valid as long as the agreement between the TNSP and the customer remains in effect and has not been renegotiated. TransGrid has stated that prudent discounts approved prior to 28 December 2006 have not been renegotiated.[503]

12.6 AER conclusion

The AER has decided not to approve TransGrid's proposed pricing methodology.

Clause 6A.12.1(e) of the NER requires that if the AER refuses to approve any aspect of a proposed pricing methodology, the AER's draft decision must include details of the changes required or the matters to be addressed before the AER will approve the proposed methodology. The matters TransGrid must address in its revised pricing methodology are:

1. TransGrid is required to propose an alternative locational pricing structure which is consistent with clause 6A.23.4(e) of the NER and does not include a measure of energy.

2. Include the additional details on its approach to allocating costs to assets that provide both prescribed entry and prescribed exit services as outlined in section 12.5.1.

While it is not a requirement under the pricing principles or the guidelines, the AER considers that it would be beneficial for TransGrid to specify the points in the transmission network where costs will be allocated and prices determined in its proposed pricing methodology. The AER requests that TransGrid provide these details in a revised proposed pricing methodology.

[503] TransGrid, response to AER information request, confidential, 26 August 2008.

Glossary

2008 APR	2008 annual planning report
AARR	average annual revenue requirement
ANSIO	Australian National State and Industry Outlook
APR	annual planning report
AR	allowed revenue
ASRR	annual service revenue requirement
AUD	Australian dollar
bppa	basis points per annum
CAPM	capital asset pricing model
CEG	Competition Economists Group
CGS	Commonwealth government securities
CIE	Centre for International Economics
CRNP	cost reflective network pricing
DMPP	demand management and planning project
DRP	debt risk premium
EBIT	earnings before interest and tax
EBITDA	earnings before interest tax depreciation and amortisation
EBSS	efficiency benefit sharing scheme
ECFM	efficiency carry forward mechanism
EGW	electricity, gas and water
EMRF	Energy market reform forum
EUAA	Energy Users Association of Australia
GWh	gigawatt hour
HRC	hot rolled coil
kV	kilovolt, (one thousand volts)
LME	London Metal Exchange
MAR	maximum allowed revenue
MITC	market impact of transmission constraints
MRP	market risk premium
MVA	megavolt ampere
MW	megawatt, (one thousand kilowatts)
MWh	megawatt hour
NC	Nuttall Consulting
NEMMCO	National Electricity Market Management Company

NPV	net present value
NSP	network service provider
NYMEX	New York Mercantile Exchange
POE	probability of exceedence
PTRM	post-tax revenue model
RAB	regulatory asset base
RBA	Reserve Bank of Australia
RFM	roll forward model
scheme	service target performance incentive scheme
SKM	Sinclair Knight Merz
SRP	Statement of principles for the regulation of electricity transmission revenues, 8 December 2004
the guidelines	pricing methodology guidelines
TUOS	transmission use of system
USD	United States dollar
WACC	weighted average cost of capital

Appendix A: Transitional arrangements

The AEMC commenced a review of the rules for economic regulation of electricity transmission networks in the NEM in mid 2005. The new chapter 6A of the NER was released in November 2006.

Roll forward of the RAB

In determining an opening regulatory asset base (RAB) for a transmission determination, the AER is bound by the relevant provisions of the NER. Clause 6A.6.1 and schedule 6A.2 of the NER outline the approach that is used to determine the opening RAB. The AER also uses its roll forward model (RFM) to determine the roll forward of the RAB.

Schedule 6A.2.1(c) of the NER provides that the RAB for the first regulatory year must be determined by rolling forward the RAB value set out in the schedule. For TransGrid this value is $3013 million (as at 1 July 2004). This value is then adjusted to allow for the difference between estimated capex and actual capex in the previous regulatory control period. Schedule 6A.2.1(f) of the NER outlines how this value is further adjusted to roll forward and calculate the value of the RAB at the beginning of the first year of the regulatory control period.

Clause 11.6.9 of the transitional provisions provides that the value of the RAB for the first regulatory control period under the revised NER may also be adjusted to have regard for an existing revenue determination and any other arrangements agreed between the AER and TNSP. The 2005 TransGrid revenue cap decision[504] was made by the ACCC based on the framework contained in its *Statement of regulatory principles for the regulation of transmission revenues* (SRP).[505] Accordingly, the AER will roll forward TransGrid's RAB consistent with the SRP.

In September 2007 the AER published its RFM and guideline based on the requirements of the NER. The capex incentive framework in the NER is consistent with the arrangements under the SRP.

Other adjustment for carryover mechanism

Clause 11.6.10 of the transitional provisions provides for adjustments to the maximum allowed revenue (MAR) arising from any carryover mechanisms implemented as part of the previous revenue determination and other arrangements agreed between the AER and TNSP. This includes the opex efficiency carry forward mechanism provided for in the ACCC's 2005 TransGrid revenue cap decision.

[504] ACCC, *TransGrid Final Decision*.
[505] ACCC, *SRP*, 8 December 2004.

Appendix B: Review of capex projects

This appendix sets out the AER's consideration of PB's recommendations relating to its detailed review of a sample of TransGrid's capex projects.

PB conducted a detailed review of nine network projects and two non-network projects. The selection of projects was undertaken in consultation with the AER and was designed to cover a broad range of projects of different sizes, across different asset classes, locations and timings. The sample list of network and non-network projects reviewed is provided in tables B.1 and B.2 respectively.

The discussion on the project reviews refers to the probability weighted cost of each project to allow the consequences of the 2008 APR to be considered against the initial proposal on a consistent basis.[506] Costs in the project reviews are detailed according to the initial proposal unless otherwise stated. As table B.1 indicates, this has resulted in a number of project costs having different costs to those presented in TransGrid's initial revenue proposal to the AER.

The AER must either accept or reject TransGrid's capex proposal on the basis of the capex criteria having regard to the capex factors. This assessment process included a detailed assessment of a representative sample of TransGrid's forecast capex projects. Where modelling or analytical errors were identified as part of this assessment this was taken into account in establishing the AER's capex allowance for TransGrid. The assessment was also designed to establish if the proposed capex allowance was affected by systematic errors.

In accordance with the ex ante framework provided for in chapter 6A, the AER's conclusions in relation to specific projects does not imply that TransGrid must implement the project in accordance with its revenue cap proposal—TransGrid has the ultimate discretion as to how it allocates its capex allowance.

[506] Refer to section 3.6.3 for a discussion of the probabilistic methodology used by TransGrid to determine its proposed capex allowance.

Table B.1: PB's detailed project review – network sample project list ($m, 2007–08)

Project name	Category	Total	Weighted average
Bannaby – South Creek 500 kV lines & substation	Augmentation (easement)	322.5	247.6
Holroyd – Chullora 330 kV cable	Augmentation (easement)	244.5	244.5
Dumaresq – Lismore 330 kV line	Augmentation	165.5	165.5
Communication – South West NSW microwave & satellite	Augmentation	4.8	4.8
Wallerawang No. 1 & 2 transformer	Augmentation	19.0	19.0
Cooma 132 kV substation replacement and new bay	Replacement (easement)	42.8	42.8
Beaconsfield West 132 kV GIS replacement	Replacement	48.1	48.1
Newcastle 330 kV substation transformer replacement	Replacement	18.9	18.9
Hunter Valley – Central Coast 500 kV lines	Easements (augmentation)	42.6	4.2
Total		908.7	795.4

Source: PB, p. 117.

Table B.2: PB's detailed project review – non-network sample project list

Project name	Forecast non-network expenditure	
	Value ($m, 2007–08)	% of total
Business IT	95.9	45.7
Vehicles	39.1	18.6

Source: PB, p. 175.

Through detailed project reviews PB examined:[507]

- $909 million of TransGrid's proposed total network capex of $2.5 billion or 32 per cent of the planned network expenditure on a scenario weighted average basis
- $135 million of TransGrid's proposed total non-network capex of $156 million or 86 per cent of the planned non-network capex.

[507] PB, pp. 116, 175.

In conducting its review, PB made an assessment of the prudence and efficiency of each project by examining:

- the drivers or justification for the project
- the alignment to TransGrid's strategies and policies
- whether all feasible alternatives had been considered
- the proposed timing for investment
- the costs and scope of the project.

Where projects have been subject to change as a consequence of the 2008 APR, this appendix includes an additional section in the analysis of those projects. These projects are the Holroyd – Chullora 330 kV cable project, the Bannaby – South Creek 500 kV lines and substation project and the Hunter Valley – Central Coast 500 kV line easement project.

Holroyd – Chullora 330 kV cable

TransGrid proposal

This project involves the installation of two 330 kV cables between the Hyland Road substation in Holroyd and a new substation proposed at Chullora. It is one part of a package of works aimed at reinforcing supply to inner Sydney in order to meet expected supply constraints in 2012–13 and to address ageing assets becoming unserviceable. The project is an augmentation project and does not involve replacement of existing assets.

This project has a proposed commissioning date of 2013 and has an estimated cost of $245 million or 9.3 per cent of TransGrid's initial total capex allowance.

While installation of one 330kV cable is identified as necessary to meet supply constraints expected in 2013, TransGrid proposed to install the second cable at the same time on the basis that it will be required to meet the expected load growth at some future date and that it is more efficient than returning at a later date to install the second cable along the same route.

TransGrid engaged J-Power Systems (JPS) to review the costs associated with laying two cables five years apart versus laying two cables at the same time. JPS found:[508]

- the installation of two cables at the same time could be completed for 180 per cent of the cost of installing one. This saving comes from the sharing of costs associated with traffic management, project management, excavation, office and site facilities and design and testing across the two cables
- the route proposed for the two cables includes a number of areas where the available installation corridor is restricted. Given that the installation of a second cable at a different time cannot be positioned as close, extra space would be

[508] PB, pp. A42–A43.

required on the second cable route. It is estimated that these deviations would add an additional 30 per cent of length, and therefore cost, to the second cable.

JPS's analysis, included in TransGrid's Holroyd – Chullora feasibility study, indicated the NPV of installing:

- one cable at year 0 was $121 million
- one cable at year 0 and the second cable at year five was $232 million
- two cables together was $216 million.[509]

The option of installing one cable was, however, dismissed by TransGrid on the basis that a second cable would be eventually required. TransGrid also highlighted non-quantifiable benefits of installing both cables at once in terms of minimising community disruption and associated planning difficulties.

On the basis of these considerations, TransGrid selected the installation of the two cables at the same time as the most prudent and efficient option for inclusion in its capex allowance.

Consultant review

PB undertook a detailed review of TransGrid's documentation relating to this project and considers that the drivers, strategic alignment and timing of the project are both prudent and efficient, and that a reasonable range of alternative options have been identified.

On the basis of the original documentation provided by TransGrid, PB considered the scope and cost efficiency of the selected option had not been demonstrated. Significantly, PB considered the need to install the second 330 kV cable within the next regulatory control period had not been demonstrated. PB also noted TransGrid had not undertaken any sensitivity analysis to demonstrate the impact of different timing options for the second cable in terms of NPV calculations. PB, therefore, initially considered that the second cable should not be installed in the next regulatory control period and recommended a reduction in TransGrid's capex allowance of $95 million.

However, following the provision of information that demonstrated the need for the second cable within 5 years of the installation of the first, PB amended its position. Specifically, information was provided that illustrated EnergyAustralia is intending to withdraw from service a number of 132 kV cables that are becoming unserviceable, which would give rise to network constraints as early as November 2015 (2 years after the proposed commissioning date of the project).[510] On the basis of the additional information provided, PB recommended that the most efficient option would be to install both cables together.[511]

[509] TransGrid, *Sydney West – Holroyd – Chullora overall feasibility study* (Document No: FS PSR 12_18_25 Rev A), p. 51.
[510] PB, p. A46.
[511] PB, p. A49.

PB, therefore, concluded TransGrid had demonstrated the need, scope and cost efficiency associated with the installation of two cables at the same time and that the capex allowance should be left unchanged. Table B.3 sets out PB's recommendation on the expenditure associated with the Holroyd − Chullora 330 kV cable augmentation project.

Table B.3: PB's initial recommendations – Holroyd – Chullora 330 kV cable ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Proposal	–	23.5	187.5	33.5	–	244.5
PB's recommendation	–	23.5	187.5	33.5	–	244.5

Source: PB, p. 119.

2008 APR and consultant updated recommendation

Following the release of the 2008 APR, the median commissioning date of this project is deferred by one year from 2013 to 2014 (under the 12 low load growth scenarios). This results in an increase in the weighted average commissioning year of 0.2 years.

PB modelled this change, along with changes associated with the escalations (see section 3.6.6), and found this resulted in a small increase in the total cost of this project in the next regulatory control period. Table B.4 sets out TransGrid's updated proposal and PB's updated recommendation on the expenditure for this project.

Table B.4: PB's updated recommendations – Holroyd – Chullora 330 kV cable ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Proposal	–	18.5	152.9	67.8	7.4	246.6
PB's recommendation	–	18.5	152.9	67.8	7.4	246.6

Source: PB, *APR 2008 supplementary report*, p. 23.

AER assessment

Based on the documents provided by TransGrid and PB's analysis, the AER considers TransGrid has identified a need to undertake investment to reinforce the supply of energy to the inner Sydney metropolitan area and has proposed the most efficient option to address this need. In particular, the AER considers that the expenditure associated with this project reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria over the next regulatory control period. The AER, therefore, recommends no adjustment to TransGrid's forecast capex allowance as the result of this project review.

That said, during the review process the AER shared PB's concerns regarding the analysis and impact of the second 330 kV cable. Specifically, if the second cable was not required within five years this would have resulted in significant changes to the NPVs of the options considered. In particular, the change in timing could have

resulted in a staged installation of the cables being the more efficient option. The AER considers TransGrid should have presented a more robust case to demonstrate the efficiency of this proposal over other alternatives earlier in the review process. The AER agrees with PB's initial concerns regarding the lack of justification for the timing of the second cable and the lack of sensitivity analysis regarding its timing. These concerns are amplified given the cost associated with this part of the project, $95 million or 3.6 per cent of TransGrid's initial total capex allowance.

Dumaresq – Lismore 330 kV augmentation

TransGrid proposal

TransGrid's proposal stated that an additional 330 kV transmission line from Dumaresq to Lismore is required by 2012 to meet growing demand on the far north coast of NSW and to address corresponding voltage and line loading limitations. In particular, the project would address a constraint arising from the combination of thermal and voltage limits in the event of outages of the 137 km long Armidale – Coffs Harbour 330 kV line. TransGrid's analysis is partially based on assumed poor reliability of Directlink which, if rectified, would help ameliorate these constraints.[512]

This project has an estimated cost of $166 million or 6.3 per cent of TransGrid's initial total proposed forecast capex allowance. The majority of this cost is comprised of 215 km of transmission line, installation of circuit breakers at Dumaresq and Lismore, easement acquisition, and allowances for scoping, design and field supervision.

TransGrid presented a range of material associated with the Dumaresq – Lismore 330 kV augmentation project, including a feasibility report and an application notice. As part of the application notice, TransGrid considered and evaluated two options:

- the development of a 215 km Dumaresq – Lismore 330 kV line
- the development of a 300 km Armidale – Lismore 330 kV line.

Of these, the Dumaresq – Lismore line was identified as the least cost option, and this was also the case under sensitivity analysis. TransGrid also considered four other network development possibilities:

- a 139 km Armidale – Kempsey 330 kV line and an associated 330/132 kV substation
- a 200 km Ebenezer (QLD) – Lismore 330 kV line
- a 300 km Armidale – Coffs Harbour – Lismore 330 kV line
- 132 kV line developments.

These further options were all dismissed as being infeasible, with most subject to problems in securing line routes in the affected region. On this basis, TransGrid

[512] TransGrid, *Application Notice, Development of Electricity Supply to the NSW Far North Coast*, April 2008, p. 28.

selected the Dumaresq – Lismore 330 kV line option for inclusion in its capex proposal.[513]

Consultant review

PB undertook a detailed review of TransGrid's documentation relating to this project and considered the drivers and strategic alignment of the project to be prudent, and that a reasonable, but not exhaustive range of alternative options were considered.

PB reported that TransGrid could not support its preferred option with a detailed internal report. PB also highlighted that as part of the retrospective economic analysis TransGrid undertook to support its proposal, the NPV of the preferred option reduced from $111 million to $76 million without any explanation, and that one of the new options (while more expensive than the preferred option) had a NPV lower than the alternative included as part of the Application Notice. In PB's view, this example highlights the risk that TransGrid adopts by not undertaking a robust and systematic economical analysis of multiple options prior to publishing its application notice.[514]

PB also found TransGrid's alternatives economic assessment: [515]

- lacked sensitivity analysis on key input assumptions, such as individual cost components/factors and deferral periods

- had not identified/quantified any market benefits that may arise as a result of the selection of their preferred option. PB noted that a project of this significance and magnitude is likely to have some material market benefits in the context of reduced transmission losses, improved inter-regional transfer capabilities and reduced intra-regional constraints.

Additional observations regarding TransGrid's proposal revolved around the project cost estimate presented by TransGrid. In particular, the cost estimate for the Dumaresq – Lismore line appears to include the cost for the survey and easement acquisition in error. The easement cost is included in the proposed capex allowance as a separate item. PB recommends this amount ($22 million) be removed from TransGrid's capex allowance for this project.[516]

PB also considered adjustments to TransGrid's capex allowance should be made to:

- remove two of the five 330kV circuit breakers proposed for the Dumaresq substation as TransGrid failed to justify these in its proposal. PB considered that the additional two circuit breakers provided limited benefits and recommended a $2.6 million adjustment to remove them from the allowance

- address a generic 'scoping cost factor on line works' of 15 per cent which was applied to the line construction costs. PB noted that this factor did not appear to have been defined in any documentation and recommended that it be reduced to 10 per cent to reflect that the scope of this project should be relatively well known. For example, TransGrid had stated that this development has captured the

[513] PB, p. A54.
[514] PB, p. A57.
[515] PB, p. A57.
[516] PB, p. A58.

'longest probable feasible line route' and is based on an existing 132 kV route. PB's recommendation results in a downward adjustment of $4.0 million

- address a 10 per cent CPI adjustment in TransGrid's modelling to incorporate two years of inflation into the cost estimate. PB considers that 6.2 per cent is more reflective of actual inflation, with a resultant reduction of $7.4 million to the project allowance.

PB concluded TransGrid had not demonstrated its proposal was reflective of a prudent and efficient TNSP and recommended a $36.4 million reduction in TransGrid' capex allowance. Table B.5 sets out PB's recommendations.

Table B.5: PB's recommendations – Dumaresq – Lismore 330 kV augmentation ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Proposal	5.5	80.0	80.0	–	–	165.5
Adjustment	–1.2	–17.6	–17.6	–	–	–36.4
PB's recommendation	4.3	62.4	62.4	–	–	129.1

Source: PB, p. 121.

AER assessment

The AER considers that TransGrid's project documentation adequately identifies the need to re-enforce the Far North Coast sub-system to overcome voltage and thermal constraints. This project has been foreshadowed for some time as part of TransGrid's Annual Planning Review processes.

The AER shares PB's concern that the cost estimate for the Dumaresq – Lismore line appears to include the cost for the survey and easement acquisition in error. On this basis, the AER supports PB's recommendation to remove the associated $22 million from the capex allowance.

Based on PB's advice, the AER also agrees with PB's observation that TransGrid has not demonstrated that the two additional circuit breakers identified above are required in the next regulatory control period. On this basis, the AER endorses PB's recommendation to remove the associated $2.6 million from the capex allowance.

The AER highlights PB's concern with the 'scoping cost factor on line works' and accepts PB's recommendation that this be reduced to 10 per cent to reflect an efficient scoping allowance. The AER supports this $4.0 million reduction as the scope of this project is relatively well known.

The AER also agrees with PB's analysis that TransGrid has applied an inflation adjustment that is too high and not reflective of the 2-year CPI escalation. The AER therefore agrees that it is more appropriate to use an inflation rate of 6.2 per cent to escalate the original cost and endorses PB's recommendation to remove $7.4 million from the proposed capex allowance.

Based on documentation provided by TransGrid and PB's analysis, the AER is not satisfied that TransGrid's proposed expenditure for this project reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria. Accordingly, the AER agrees with the proposed amendments put forward by PB and has made a reduction of $36 million to TransGrid's capex allowance as a result of this project review. The AER is accordingly satisfied that an allowance of $129 million reasonably reflects the capex criteria.

Cooma 132 kV substation replacement

TransGrid proposal

TransGrid's proposal stated the Cooma 132 kV substation will need to be replaced by 2014 due to its condition and issues with the arrangement of the substation. TransGrid noted the substation was established in 1954 and that most of the plant is approaching the end of its serviceable life. This project has an estimated cost of $43 million or 1.6 per cent of TransGrid's initial total capex allowance.

The project involves the development of a 132/66 kV substation on a suitable site away from the existing Cooma substation to avoid line congestion and accommodate connection of the second Bega 132 kV line. The scope of works includes the establishment of new 66 kV switchgear and the reconstruction of a section of line as a 132 kV double circuit line.[517]

TransGrid's documentation on the Cooma 132kV substation replacement included options on how to proceed with the project, namely reconstruction of the substation:

- in-situ—(with or without a busbar replacement)
- on a new site—near or remote from the current site.

TransGrid's assessment of the NPV of each option and its impact in terms of risk reduction is presented in table B.6.

Table B.6: NPVs and risk scores of Cooma 132 kV substation options

Option	NPV ($m)	Risk score
Do nothing	n/a	287.6
Remote (new site) reconstruction	–16.57	40.2
In-situ project package including busbars	–13.05	116.8
In-situ project package excluding busbars	–10.24	148.8

Source: PB, p. A83.

[517] TransGrid, *Project Option Scope and Estimate − Cooma North 132/66 kV Substation* (Document No. 6194b, Revision No. 2), p. 1.

TransGrid concluded remote reconstruction was its preferred option as it:

> … has the best improvement in risk score, fully provides for future site expansion, fully overcomes the issues of the existing site and legacies of past design compromises, provides full life for site infrastructure; has the lowest risks associated with implementation and greatest confidence in feasibility; avoids future issues associated with the present busbars and disconnectors. [518]

Consultant review

PB undertook a detailed review of TransGrid's documentation relating to this project and determined the Cooma 132 kV substation has a range of condition and design related issues. While PB considered it would be prudent to address these issues it noted TransGrid's assessments did not conclude there were any clear risks the substation's transformers and regulators would fail.

PB noted the following concerns with TransGrid's consideration of project alternatives:

- full consideration was not given to the refurbishment of the transformers and regulators, particularly since they were regarded as aged but still serviceable
- provision for a 330 kV substation layout was made in the remote replacement option but not in the other options. The justification for this provision was not provided by TransGrid
- TransGrid included a provision of $9.4 million for new control and protection in the in-situ replacement options. PB considered a more appropriate allowance for this work to be $1 million, thus the costs of the in-situ options are significantly overstated.

Based on TransGrid's costing and documentation, PB consequently considered the most efficient option would be the in-situ refurbishment of the substation (without busbar works). Selecting this option would also result in the removal of the $0.6 million associated with Cooma easement from the capex allowance.

PB concluded that while it is prudent to address the identified need, the selected option was not representative of efficient investment. Table B.7 sets out PB's recommendation on the prudence and efficiency of the submitted expenditure associated with the Cooma 132 kV substation replacement project.

Table B.7: PB's recommendations – Cooma 132 kV substation replacement ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Submitted	–	–	1.1	11.5	30.2	42.8
Plus easements	–	0.1	0.5	–	–	0.6
Adjustment	4.8	4.8	3.8	–6.5	–25.2	–18.2
PB's recommendation	4.8	4.9	4.9	5.0	5.0	24.6

[518] TransGrid, *Network asset replacement project evaluation − Cooma substation*, p. 13.

Source: PB, p. A86.

AER assessment

Based on documents provided by TransGrid and PB's advice, the AER considers TransGrid has identified a need to address the condition and related issues of the existing Cooma substation. Rectification of these issues by TransGrid is necessary to maintain the security and reliability of transmission services.

Regarding TransGrid's assessment of options, the AER recognises that factors outside of NPV assessments, in this case quantified risk reductions, are valid in making investment decisions. However, such factors need to be rigorously and systematically examined, particularly in the case where they lead to the selection of an investment option which has the highest cost.

PB's report expressed the NPV of each of TransGrid's options in terms of dollar per unit of risk reduction as shown in table B.8.

Table B.8: $ per unit of risk reduction of Cooma 132 kV substation replacement options

Option	NPV ($m)	Risk Score	$ per risk score reduction ($m)
Do nothing	n/a	287.6	n/a
Reconstruct (remote reconstruction option)	–16.57	40.2	–0.07
In-situ project package including busbars	–13.05	116.8	–0.08
In-situ project package excluding busbars	–10.24	148.8	–0.07

Source: PB, p. A83.

During discussions with TransGrid it was apparent to the AER that comparisons on a dollar per unit of risk reduction basis should not be used to draw conclusions on the merits of each option. However, it was acknowledged by TransGrid and PB that some form of 'value for money' consideration was important. A simple comparison of the risk per NPV as expressed by PB indicates the difference in the cost of each option is due to commensurate risk reductions.

As noted above, PB suggested TransGrid has overstated the cost of 'new control and protection' in the in-situ replacement options by $8.4 million (or roughly one third of the cost of these options). If this is correct, the remote reconstruction option becomes far less favourable, further underlying the need for robust and comprehensive analysis to inform decisions. In this context, the AER considers TransGrid's assessment of this particular project does not demonstrate to the AER that the option chosen reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, as required by clause 6A.6.7(c).[519]

Through consideration of the information presented by TransGrid and PB's analysis, the AER considers that a prudent TNSP in TransGrid's circumstances would not have selected the option that was proposed in TransGrid's capex proposal. The AER is

[519] NER, clause. 6A.6.7(c)(2).

therefore not satisfied that TransGrid's proposed expenditure for this project reasonably reflects the efficient costs a prudent TNSP in TransGrid's circumstances would incur to achieve the capex objectives consistent with the capex criteria. Accordingly, the AER agrees with the proposed amendments put forward by PB and has made a reduction of $18 million to TransGrid's capex allowance as a result of this project review. The AER is accordingly satisfied that an allowance of $25 million (inclusive of the reduction associated with the easement) reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, in accordance with the capex criteria.

Bannaby – South Creek 500 kV lines and substation

TransGrid proposal

TransGrid's proposal stated new line reinforcement is required between Bannaby and Sydney by 2013–14 due to growing load in the Newcastle – Sydney – Wollongong area.[520] This project is expected to be commissioned in 2014 and has an estimated cost of $248 million or 9.4 per cent of TransGrid's initial capex allowance.

This project involves the rebuilding of the existing 330 kV line from Bannaby (39 line) as a 500 kV circuit. At South Creek, in the Luddenham area to the west of Sydney, the 39 line crosses the existing Eraring to Kemps Creek line. TransGrid also proposed to establish a new 500/330 kV substation in this location, turn in the Eraring to Kemps Creek line, and connect the new 500 kV Bannaby line.

This project is part of TransGrid's long term strategy to progressively develop a 500 kV system around the Newcastle – Sydney – Wollongong load corridor, and aligns with its NSW Main System Outline Plan, and APRs.

TransGrid presented a detailed analysis on the options considered to meet the development of western or southern generation in conjunction with expected load growth in the Newcastle – Sydney – Wollongong load corridor. In summary, the supply reinforcement options and developments considered by TransGrid broadly included:[521]

- reactive support within the load corridor
- reactive support at major power stations which are critical to supporting the voltage in the load corridor
- rearrangement of 330 kV circuits to the west of Vales Point
- development of a 500 kV link between Bannaby and Sydney
- development of a 500 kV link between the Hunter Valley and the coast.

[520] TransGrid 2008, *Project Evaluation Summary – Reinforcement of Supply to the Newcastle − Sydney − Wollongong Load Corridor* (Document Number: PES 5567, Project Number 5567, Revision 2), p. 6.

[521] TransGrid 2008, *Project Evaluation Summary – Reinforcement of Supply to the Newcastle − Sydney − Wollongong Load Corridor*, p. 6.

These supply reinforcement options and developments are expanded in PB's report on TransGrid's proposal.[522]

Based on its analysis, TransGrid selected the option of a double circuit 500 kV line from Bannaby into Sydney for inclusion in its capex allowance.

Consultant review

PB undertook a detailed review of TransGrid's documentation relating to this project and determined that the drivers, strategic alignment and cost of the project are prudent and efficient.

PB considered that while a reasonable range of alternative options had been identified, the options analysis presented demonstrated scope for improvement. In particular, PB raised concerns with:

- while costs were presented, no consideration was presented of the comparison of the NPVs of the various options
- the assessment of options not being subjected to sensitivity analysis, which was relevant given the similar costs of the line route and termination options for the 500 kV Bannaby to Sydney development
- the 'do nothing' option was not explicitly presented and could have provided a more robust reference point for considering other options.

Notwithstanding these concerns, PB acknowledged the qualitative assessment of the costs and benefits presented by TransGrid demonstrated the relative merits of the preferred option over the alternatives.

PB also noted the unit costs used by TransGrid for this project were 'in general on the high side' of its expectations. PB concluded, however, that these costs were efficient, citing the:

- infrequency and specialised nature of installing 500 kV transmission lines
- limited experience on which to base its expectations.

PB concluded the project is prudent and that the most efficient investment option had been selected. Table B.9 sets out PB's recommendation on the prudence and efficiency of the capex allowance associated with this project.

Table B.9: PB's recommendations – Bannaby – South Creek 500 kV lines and substation ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Proposal	1.7	9.8	62.6	110.4	63.1	247.6
PB's recommendation	1.7	9.8	62.6	110.4	63.1	247.6

Source: PB, p. A37.

[522] PB, pp. A24–31.

2008 APR and consultant updated recommendation

Following the release of the 2008 APR, the median commissioning date of this project is deferred by one year from 2014 to 2015. This results in an increase in the weighted average commissioning year of 0.9 years.

PB modelled this change and found this resulted in a decrease in the total cost of this project in the next regulatory control period. Table B.10 sets out TransGrid's updated proposal and PB's updated recommendation on the prudence and efficiency of this project.

Table B.10: PB's updated recommendations – Bannaby – South Creek 500 kV lines and substation ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Proposal	0.4	1.5	8.9	55.0	100.7	166.5
PB's recommendation	0.4	1.5	8.9	55.0	100.7	166.5

Source: PB, *APR supplementary report,* p. 22.

AER assessment

Based on documents provided by TransGrid and PB's analysis, the AER recognises that a key driver of this project is the expected load growth in the Newcastle – Sydney – Wollongong load corridor.

The AER notes that TransGrid identified and considered a range of practical alternatives to meet the expected load growth in this area and that of all the options considered the Bannaby – South Creek option was the most preferred.

While acknowledging the number of options identified and costed, the AER agrees with PB's analysis that NPV analysis could have been more extensive given the relative size of this project. Using NPV analysis early in the option selection processes generally facilitates the selection of the most prudent and efficient option. That said, the AER notes that qualitative assessment of the costs and benefits provided by TransGrid has demonstrated the merits of the preferred option over the alternatives.

The AER shares PB's expectations regarding the role of sensitivity analyses in that they should be used by TransGrid in its investment decision making processes, particularly for large and specialised projects.

Having considered the material presented by TransGrid and PB's analysis, the AER is satisfied that the costs associated with the Bannaby – South Creek 500 kV lines and substation option reasonably reflect the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, in accordance with the capex criteria.

Communication – South West NSW microwave and satellite

TransGrid proposal

TransGrid's proposed expenditure for this project will provide SCADA facilities at substations on the Wagga – Darlington Point system in accordance with a request

from NEMMCO and requirements under the NER.[523] This project has commissioning dates throughout the next regulatory control period and has a cost of $4.8 million or 0.2 per cent of TransGrid's initial capex allowance.

TransGrid presented a range of material outlining the need for this project, including:

- correspondence from NEMMCO outlining the desirability and need for such projects in South West NSW
- internal discussion papers
- communications outline plans, dealing with the rationale for, and a description of, the developments that are expected to be required within TransGrid's telecommunications network over the next decade.

TransGrid examined a number of alternative options for communications at its substations, such as power line carrier, microwave radio and satellite communications, but in most instances it has been restricted to a single technology, due to a number of factors, including geography.

Consultant review

PB conducted a detailed review of TransGrid's documentation relating to this project and is of the view that the project is:

- prudent, given industry standards and NEMMCO requirements
- efficient, given that where there has been a choice of technology options available, TransGrid has chosen the least cost option.

Table B.11 sets out PB's recommendation on the prudence and efficiency of the submitted expenditure associated with the project.

Table B.11: PB's recommendations – Communication – SW NSW microwave & satellite augmentation ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Proposal	0.2	4.6	–	–	–	4.8
PB's recommendation	0.2	4.6	–	–	–	4.8

Source: PB, p. 121.

AER assessment

The AER considers TransGrid has adequately justified the need for the expenditure associated with this project. In particular, the AER notes:

- the NER and general industry practice require transmission substations to have SCADA facilities

[523] TransGrid 2008, *Project Evaluation Summary – Provision of communication services to 132 kV substations in south − western NSW*, paragraph 1.2.1.

- NEMMCO has requested TransGrid to undertake specific action to address communications issues in South West NSW.

The AER, therefore, is satisfied the costs associated with the project reasonably reflect the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, in accordance with the capex criteria.

Wallerawang No. 1 & No. 2 transformers

TransGrid proposal

TransGrid's proposal involves the commissioning of two 330/132 kV transformers at Wallerawang in 2010. It noted the existing transformers are around 30 years old, of a non-standard size and scope and need replacing. This project has an estimated cost of $19 million or 0.7 per cent of TransGrid's initial capex allowance.

TransGrid's proposal noted:

- in 2007, the No. 1 transformer failed due to a close up through fault
- the No.2 transformer is the same age as the No. 1 transformer and is subject to the same fault conditions that caused the No. 1 transformer to fail
- the unit that replaced the No. 1 transformer is a temporary transformer sourced from ElectraNet and is not fully compatible with the existing supply arrangements[524]
- due to the temporary nature and placement of the temporary replacement, maintenance to the No. 2 Transformer cannot occur.

TransGrid presented a range of analysis on this project, including four options and a risk assessment of the 'do nothing' option.[525] The options considered included:[526]

- replacing transformers and re-arrange existing supply arrangement with 330/132/11 kV, 375 MVA transformers
- replacing transformers and existing supply arrangement with specially constructed 375 MVA transformers
- replacing the No. 2 transformer only—this option was not, however, considered for evaluation and no costing was provided
- establishing a 330/132 kV transformer bay in the 330 kV switchyard as a contingency plan for the failure of the No. 2 transformer—this option was not, however, considered for evaluation and no costing was provided.

TransGrid's NPVs for the feasible options is provided in table B.12.

---

524 TransGrid 2008, *Project Evaluation Summary – Replacement of Wallerawang 330/132 kV Transformers* (Project Number: 5625, Revision No. 1), pp. 4–5.

525 The risk assessment was determined in accordance with GM AS G2 025 – Network Asset Replacement Project Evaluation.

526 TransGrid 2008, *Network Asset Replacement Project Evaluation – Wallerawang No. 1 and No. 2 Transformers* (Document Number: 5625 ARPE, Revision Number: 2), pp. 11–14.

Table B.12: NPVs of Wallerawang No. 1 and No. 2 transformer replacement options

Option	NPV ($m)
Do nothing	–
Replace (both) transformers and re-arrange supply arrangements	–$11.97
Replace (both) transformers – existing supply arrangements	–$7.42

Source: PB, p. A71.

TransGrid indicated that replacement with a re-arranged supply arrangement, the most expensive option, is the preferred option as:[527]

- it removes outage access constraints
- it addresses reliability issues at Wallerawang and restores normal duplicated supply to Wallerawang Power Station as well as enabling faster supply restoration due to the availability of spares
- outage requirements for construction and commissioning are manageable
- it minimises environmental exposure through upgrade of oil containment system
- it allows full separation of functions from the power station site—that is, transformers are no longer located on the power station runway, and control and protection systems are separated.

On this basis, TransGrid selected the replacement of both the No. 1 and No. 2 transformers with new 375 MVA units for inclusion in its capex allowance.

Consultant review

PB conducted a detailed review of TransGrid's documentation relating to this project and is of the view that TransGrid has identified and assessed appropriate options for this specific need.

PB considered TransGrid had not considered the overarching needs of the site in a cohesive manner and it had sought to minimise its lack of strategic planning by resolving these issues at the detailed design stage, or in the field through works scheduling – a practice that is neither effective nor efficient. Specifically, PB noted that while it is satisfied with the alternatives considered, it considered that if TransGrid's strategic planning is improved it would permit greater efficiencies to be captured. For example, the costs of another proposed project at this site (i.e. the Wallerawang 132 kV substation switchyard rebuild) could be reduced if it was undertaken in conjunction with replacement of these transformers. That is, a prudent TNSP should be able to deliver both projects on this site in a more holistic and efficient manner.

PB also considered TransGrid's options analysis was incomplete as it failed to include all relevant costs and benefits, and failed to reasonably demonstrate the efficiency of

[527] TransGrid 2008, *Project Evaluation – Wallerawang No. 1 and No. 2 Transformers*, pp. 13–14.

the chosen option over the alternatives. Consequently, PB could not conclude the most efficient option had been chosen. However, PB recognised it was likely, with the inclusion of all relevant costs and benefits, and the consideration of all other proposed works at the Wallerawang site, that replacement of both transformers with new supply arrangements would be the most efficient option.

PB, therefore, recommended a $0.3 million reduction in the project management costs to account for the duplicated mobilisation/demobilisation and project management inefficiencies. Table B.13 sets out PB's recommendation on the prudence and efficiency of the expenditure associated with the proposed Wallerawang No.1 and 2 transformer replacement project.

Table B.13: PB's recommendations – Wallerawang No. 1 and 2 transformer replacement ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Proposal	19.0	–	–	–	–	19.0
Adjustment	–0.3	–	–	–	–	–0.3
PB's recommendation	18.7	–	–	–	–	18.7

Source: PB, p. A74.

AER assessment

The AER notes the replacement of the No. 1 and No. 2 transformers at Wallerawang substation is detailed in TransGrid's substations asset management strategy and that PB found the documentation presented on this project is in accordance with that strategy.

Notwithstanding the selection of a more expensive option for inclusion in the capex allowance, based on the material presented by TransGrid and PB's analysis, the AER considers the replacement of both transformers and the re-arrangement of supply arrangement is reasonable and represents a prudent and efficient option. This determination has been reached following careful consideration of the circumstance associated with the plant failure, the replacement of the failed unit with non-standard equipment and the range of benefits associated with the selected option (as detailed above).

The AER also notes PB's recommendation that there is scope for some efficiencies to be captured through more effective planning of proposed works at this site. The AER considers TransGrid's proposal is on the high side but, on balance, considers it not to be unreasonable. The AER is therefore satisfied the expenditure sought for this project reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria. Consequently, the AER leaves TransGrid's capex allowance for this project unchanged.

Beaconsfield West 132 kV gas insulated switchgear replacement

TransGrid proposal

TransGrid's proposal indicates the 132 kV gas insulated switchgear at Beaconsfield West 132 kV substation is approaching the end of its serviceable life and needs to be replaced in the near future.[528] This project involves the replacement of this switchgear and the extension of the building that houses this equipment to facilitate the replacement.

This project is expected to be commissioned in 2013 and has an estimated cost of $48 million or 1.8 per cent of TransGrid's initial capex allowance.

TransGrid's assessment of the switchgear identified a number of condition based issues, specifically:

- slow circuit breaker operation due to defective valves
- gas leaks
- compressor failure.

TransGrid highlighted this equipment is currently leaking SF_6, which is a damaging greenhouse gas. Availability of spare parts, limited internal expertise and limited supplier support for this specialist and relatively rare plant were also raised as concerns.

TransGrid presented condition reviews, an outline plan detailing the potential transmission developments required in the greater Sydney and CBD areas, an asset management strategy for substations and a project evaluation.

In terms of options considered, TransGrid examined both refurbishment and replacement options, which included consideration of the costs and benefits of replacement in-situ as well on a new site. TransGrid's NPV analysis of each option is in table B.14.

Table B.14: NPV analysis of Beaconsfield West 132 kV GIS replacement options

Option	NPV ($m)
Do nothing	–
Replace in-situ	–21.67
Replace on a new site	–21.42
Replace two (2) circuit breakers and refurbish	–12.44

Source: PB, p. A94.

[528] TransGrid 2008, *Condition Review − Beaconsfield West Substation GIS*, pp. 1−2.

TransGrid notes the following advantages associated with the in-situ replacement option, some which are relative to replacement on a new site:[529]

- it avoids the need to rejoin EnergyAustralia's 132 kV cables
- it does not require the purchase of additional land in a built up urban area
- it would resolve the condition-based issues associated with the 132 kV switchgear and restore the reliability standard
- full manufacturer's support would be available
- it would resolve existing busbar arrangement problems.

While it was the least cost option, TransGrid noted the residual risk of the refurbishment option was unacceptable.

Based on this analysis, reconstruction of the 132 kV sub-station on the existing site was selected as TransGrid's preferred option for inclusion in its capex allowance.

PB review

PB found the drivers, strategic alignment and timing of the project were prudent and efficient, and that a reasonable range of alternative options were identified. PB is of the view that the Beaconsfield West 132 kV gas insulated switchgear replacement aligns with TransGrid's substations asset management strategy.

However, PB found that its option analysis was incomplete due to a number of costs being excluded in TransGrid's NPV analysis and that the inclusion of these omissions could result in potentially significant changes to the NPVs of the options considered. For example, with the refurbishment option, the cost to extend the gas insulated switchgear to accommodate the EnergyAustralia 132 kV feeders in 2012 is explicitly stated as not being included in the NPV calculation. For the replacement option at a new site, the NPV analysis did not include the acquisition cost of the additional land required.

PB also noted that while some analysis of the sensitivity to key input assumptions was undertaken, this did not alter the rankings of the options and therefore project selection. PB considered the sensitivity analysis undertaken by TransGrid failed to demonstrate the impacts on the option selection of the variance in the uncertain costs and benefit estimates.

PB concluded it could not determine that the most efficient option had been selected for inclusion in the capex forecast. It did, however, note that while the highest cost option had been selected, this may not have been the highest cost option had the all missing costs and benefits been included in its analysis.

Regarding the cost estimate of the preferred option, PB noted particular concern with the application of two scoping factors. In particular, the design cost factor (DCF)[530]

---

[529] TransGrid 2008, *Network Asset Replacement Project Evaluation − Beaconsfield West 132 kV Gas Insulated Switchgear Replacement* (Document No. 6378 ARPE, Rev. 1), p. 11.

and network cost factor (NCF)[531] had been doubled due to the difficulties of working at an operational site, and due to the one off nature of the work.

While PB accepted there were issues associated with the site that would increase its costs it considered that the justification for the doubling of these costs lacked transparency and could not be considered reflective of an efficient and prudent TNSP. PB, therefore, recommended a –$8.1 million correction for what is considered to be an unjustified increase in DCF and NCF factors in the Beaconsfield West project. This represented 0.89 per cent of the value of the reviewed projects.[532]

PB also found the lack of transparency in the application of those factors was likely to be a systemic issue with regard to this cost estimating and options analysis process. It recommended that an adjustment be made to the portion of the ex ante capex portfolio that had not been subject to detailed review. If a 0.89 per cent adjustment is applied on a pro-rata basis across the unreviewed capital works portfolio of TransGrid's initial capex proposal, a correction of –$13.9 million needs to be applied. However, following the release of the 2008 APR, and TransGrid's subsequent reduction in its capex program, this correction is revised to $13.2 million.[533]

Table B.15 sets out PB's recommended changes to the expenditure associated with this project.

Table B.15: PB's recommendations – Beaconsfield West 132 kV GIS replacement ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Proposal	2.4	7.2	10.5	28.1	–	48.1
Adjustment	–0.4	–1.2	–1.8	–4.7	–	–8.1
PB's recommendation	2.0	6.0	8.7	23.4	–	40.1

Note: Totals may not add up due to rounding.
Source: PB, p. 125.

AER assessment

Based on the documents provided by TransGrid and PB's analysis, the AER considers TransGrid has identified that the 132 kV gas insulated switchgear at Beaconsfield West has significant condition problems.

Regarding PB's concerns with TransGrid's options assessment, the AER acknowledges that, in this case, the need for more rigorous assessment was arguably not as apparent to TransGrid given the condition issues with these assets. However, the AER considers the omission of certain costs and benefits from TransGrid's options analysis (and associated documentation) is a significant shortcoming. This

530 DCF includes all costs associated with the design, specification preparation, tendering process, the environmental assessment and the project management of a project.
531 NCF includes all the costs associated with field supervision, site management and commissioning of the project.
532 PB, *APR 2008 supplementary report*, p. 29.
533 PB, *APR 2008 supplementary report*, p. 29.

shortcoming appears to stem from the reliance on engineering judgement which, while not a problem per se, has not been transparently applied in TransGrid's assessment process. The AER notes that while this has not materially affected the outcome in terms of TransGrid's preferred option in this case, as the inclusion of all appropriate costs and benefits may have yielded the same result. The extent to which a similar conclusion can be reached for other parts of TransGrid's capex proposal is, however, unclear and is reflected in similar concerns shared by PB and the AER regarding TransGrid's options assessment for other capex projects.

Regarding TransGrid's cost estimation, the AER is also concerned with the lack of documentation or rationale for the application of the scoping factors associated with the in-situ replacement option. The lack of documentation means the efficiency of TransGrid's approach cannot be ascertained with any certainty. The AER also considers, based on PB's advice, that other cost components have been overstated. To address these issues, the AER considers the adjustments proposed by PB as a result of findings for this project should be applied across the remainder of TransGrid's capex allowance.

The AER, therefore, is not satisfied that TransGrid's proposed expenditure for the Beaconsfield West 132 kV GIS replacement reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria. Accordingly, the AER agrees with the proposed amendments put forward by PB in relation to the application of the scoping factors and has made a reduction of $8.1 million to TransGrid's capex allowance as a result of this project review.

Newcastle 330 kV substation transformer replacement

TransGrid proposal

TransGrid's proposal indicates the existing banks of single-phase transformers at Newcastle Substation are around 35 years old and need to be replaced as they are reaching the end of their serviceable lives.[534] This project has a commissioning date of 2013 and has an estimated cost of $19 million or 0.7 per cent of TransGrid's initial capex allowance.

The project scope covers the replacement of six single-phase transformer units with two new three-phase units. The three most serviceable single-phase units would be used to extend the life and reliability of the remaining single-phase transformer set. Secondary systems replacement and oil containment upgrade work has also been included in the project scope.[535]

TransGrid presented internal condition reports on the transformers, the substation asset management plan and analysis exploring the options available to address the problem. A network asset replacement project evaluation was also provided, which explored whether replacement or refurbishment of the transformers was the preferred option.

[534] TransGrid, *Network Asset Replacement Project Evaluation 5622 ARPE*, June 2008, p. 6.
[535] TransGrid, *Project Option Scope and Estimate 5622*, June 2008, p. 4.

The NPV of each option, with the exception of the do-nothing option is presented along with its impact in terms of risk reduction.

Table B.16: NPVs and risk scores of Newcastle 330 kV substation transformer replacement options

Option	NPV ($m)	Risk score
Do nothing	n/a	175.4
Replace one transformer	–6179	145.2
Replace two transformers	–8210	115.0
Replace three transformers	–10 278	79.0
Refurbish existing transformers	–4153	158.2

Source: PB, p. A110.

TransGrid concluded that the replacement of two transformers option was its preferred option even though it was not the highest NPV option on the basis that it:

- reduces the transformer failure risk to an acceptable level
- represents the lowest cost option of reducing the risk to the acceptable level
- generates additional spares to extend the service life of the remaining single phase units.

TransGrid also stated its decision to replace two transformer sets instead of replacing:

- a single transformer set was made on the basis that the replacement of a single transformer set, although less expensive, does not meet TransGrid's acceptable risk score outcome for replacement or refurbishment projects
- all three transformers has been made on the basis that the two transformer replacement option meets TransGrid's acceptable risk criterion and therefore no further expenditure is justified.

PB review

PB conducted a detailed review of TransGrid's documentation relating to this project and concluded the drivers, strategic alignment, cost and timing of the project are demonstrated to be both prudent and efficient, and that a reasonable range of alternative options had been identified.

PB found TransGrid's acceptable risk criteria and their derivation are not explicitly stated in TransGrid's policy documentation, risk assessment guidelines, or the project documentation itself. In addition, PB found that no acceptable risk scores had been identified in other project types. On this basis, PB concluded that the derivation of the criteria for transformer replacement was arbitrary. PB did, however, acknowledge that, in general, the use of an acceptable risk criterion is a reasonable basis for

evaluating the value of the risk reduction to a project for the purpose of option selection on the basis it is pre-defined, documented and authorised.

Based on TransGrid's documentation, PB consequently considered the most efficient option to be the single transformer replacement option. Table B.17 sets out PB's recommendation on the prudence and efficiency of the submitted expenditure associated with the Newcastle 330/132 kV transformer replacement project.

Table B.17: PB's recommendations – Newcastle 330/132 kV transformer replacement ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Submitted	–	–	1.3	17.6	–	18.9
Adjustment	–	–	–	–10.5	–	–10.5
PB's recommendation	–	–	1.3	7.2	–	8.4

Source: PB, p. A113.

AER assessment

Based on the documents provided by TransGrid and PB's analysis, the AER considers the replacement of the Newcastle 330/132 kV transformer is appropriate and that it aligns with TransGrid's substations asset management strategy and Newcastle area supply strategies.

Regarding TransGrid's assessment of options, the AER recognises that factors outside of NPV assessments, in this case quantified risk reduction, are valid in making investment decisions. However, where there is a reliance on achieving an 'acceptable risk score' in the selection of a preferred option for inclusion in a capex proposal there is a need for such an approach to be transparent. In particular, there is a need for acceptable risk scores that are pre-defined and documented, particularly where they lead to the selection of an investment option that has a higher cost than other options available.

PB's report expressed the NPV of each of TransGrid's options in terms of dollar per unit risk reduction as shown in table B.18.

Table B.18: $ per unit of risk reduction of Newcastle 330 kV substation transformer options

Option	NPV ($m)	Risk score	$ per risk score reduction ($m)
Do nothing	–	175.4	–
Replace one transformer	–6179	145.2	–204.6
Replace two transformer	–8210	115.0	–135.9
Replace three transformer	–10 278	79.0	–106.6
Refurbish existing transformers	–4153	158.2	–241.5

Source: PB, p. A110.

As discussed in the Cooma 132 kV substation replacement review, it is also apparent to the AER that comparisons on a dollar per unit of risk reduction basis should not be used to draw conclusions on the merits of each option. However, it was acknowledged by TransGrid and PB that some form of 'value for money' consideration was important in cases such as this.

Based on the information provided by TransGrid and PB's analysis, the AER therefore agrees with PB's recommendation to reduce TransGrid's capex allowance to reflect the selection of the most efficient option as assessed in TransGrid's documentation (replacement of a single transformer). Again, it is TransGrid's lack of transparency with respect to non-economic considerations that needs to be addressed if these are the determining factors in selecting one option over another for inclusion in its capex allowance.

The AER is therefore not satisfied that TransGrid has reasonably demonstrated that the replacement of two transformers reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria. The AER has therefore reduced TransGrid's capex allowance by $10.5 million.

Hunter Valley – Central Coast 500 kV line easement

TransGrid proposal

TransGrid's proposal indicates the growing load in the Newcastle – Sydney – Wollongong area necessitates this project and that it represents an important aspect of TransGrid's strategy to cover all potential future generation developments.[536] The easement will be used in the construction of a 500 kV transmission line between Bayswater and Eraring. The project has an estimated cost of $4.2 million or around 0.2 per cent of TransGrid's initial capex allowance.[537]

TransGrid presented a range of documents associated with this proposal, including a feasibility study that examined the possible corridors where a 500 kV transmission line is feasible and estimates on the cost and program duration directly related to the construction of a 500 kV transmission line. Northern, central and southern corridors were identified through this analysis and it was noted that the opportunity exists in a number of locations to connect between the proposed corridors allowing portions of each corridor to be utilised for a final corridor option.

On the basis of its options analysis, TransGrid selected the Hunter Valley – Central Coast 500 kV line easement as the most appropriate corridor.

PB review

PB reviewed TransGrid's documentation relating to this project and considered the drivers, strategic alignment and timing of the project are prudent and efficient, and that a reasonable range of alternative options were identified.

---

536 TransGrid, *Project Feasibility Study Report FS PSR 119, Rev 0*, February 2008, p. 1.

537 Due to TransGrid's use of a probabilistic method in developing its proposal, effectively only 6.8 per cent of the value of this easement is included in TransGrid's proposed ex ante allowance

However, PB noted TransGrid had:[538]

- identified but excluded a range of 330 kV options due to concerns with voltage control constraints and/or the need for further easements, in heavily constrained or environmentally sensitive areas
- failed to provide an assessment of the timing and quantity of future transmission line corridors that may be required.

PB could not, therefore, determine whether the exclusion of the 330 kV options was prudent. However, PB recognised the specific option selected has little material impact on expenditure as it relates primarily to an easement acquisition and preliminary works. Moreover, due to TransGrid's use of a probabilistic method in developing its proposal, effectively only 6.8 per cent of the value of this easement is included in TransGrid's capex allowance.

PB also found:[539]

- a $6.5 million disparity in easement costs between similar 330 kV and 500 kV line routes between Eraring and the Hunter Valley (corrected for easement width) which it considered unreasonable
- the property costs detailed were higher than that specified in a feasibility study provided by TransGrid
- no specific easements had been identified.

PB concluded it could not determine the project represented efficient expenditure and recommended the easement expenditure be reduced to reflect the costs contained in TransGrid's feasibility study. Table B.19 sets out PB's recommendation on the prudence and efficiency of the submitted expenditure associated with the Hunter Valley – Central Coast 500 kV lines easement project.

Table B.19: PB's recommendations – Hunter Valley – Central Coast 500 kV lines ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Proposal	–	–	0.2	2.1	1.9	4.2
Adjustment	–	–	–	–0.1	–0.9	–1.0
PB's recommendation	–	–	0.2	2.0	1.0	3.2

Source: PB, p. A124.

2008 APR and consultant updated recommendation

Following the release of the 2008 APR, the Hunter Valley to Central Coast 500 kV transmission line project has been removed from TransGrid's proposed capex allowance for the next regulatory control period. However, TransGrid advised that a

[538] PB, pp. A121–122.
[539] PB, p. A123.

$7.2 million strategic easement acquisition in the Hunter Valley is required in 2014 to support the implementation of its 500 kV ring strategy.

PB noted TransGrid's revised easement proposal is $3.0 million higher than the initial proposal, despite a deferral of the transmission line project itself. PB acknowledged the need for strategic easements but considered that TransGrid had previously considered the extent of the early easement acquisition and that it has identified no specific changes to the easement acquisitions arising from the release of the 2008 APR.

PB therefore maintained its recommendation with respect to TransGrid's initial proposal for this project, being an allowance of $3.2 million.[540] Table B.20 sets out TransGrid's updated proposal and PB's updated recommendation on the prudence and efficiency of this project.

Table B.20: PB's updated recommendations – Hunter Valley – Central Coast 500 kV lines ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Proposal	–	–	–	–	7.2	7.2
Adjustment	–	–	0.2	2.0	–6.2	–4.0
PB's recommendation	–	–	0.2	2.0	1.0	3.2

Source: PB, *2008 APR supplementary report*, p. 25.

AER assessment

Based on the documents provided by TransGrid and PB's analysis, the AER considers the purchase of easements to facilitate the completion of the 500 kV project is of strategic importance and forms part of TransGrid's long term planning strategy.

The AER notes TransGrid's project documentation contains indicative costs only and that, as PB identified, there is a lack of supporting evidence to justify how these estimates have been derived. Furthermore, the AER notes PB found the costs associated with the proposed easement were not reflective of efficient and prudent investment. On this basis, the AER considers TransGrid has not demonstrated the efficiency of the proposed cost of this project for a TNSP in TransGrid's circumstances.

Consequently, the AER is not satisfied the proposed costs are the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, in accordance with the capex criteria. The AER has therefore made an adjustment of $4.0 million and is accordingly satisfied an allowance of $3.2 million reasonably reflects the capex criteria.

[540] PB. *APR 2008 supplementary report*, pp. 24–25.

Non-network – business IT

TransGrid proposal

Business IT is the largest expenditure category within the total non-network capex. TransGrid proposed an allowance of $96 million over the next regulatory control period. This accounts for around 3.7 per cent of the initial capex allowance.

TransGrid provided high level information on IT in its revenue proposal. Detail on how its IT expenditure is managed is contained in three documents that were provided to the AER and PB:

- Technology strategy 2008—this covers a five year period (2009–10 to 2013–14) and identifies the large-scale business IT expenditure it has proposed[541]
- IT Asset management plan—this establishes the policy and overall plan for the management of IT assets within TransGrid. The scope of this plan is defined in the IT management framework[542]
- IT management framework—this details the specific strategies for IT equipment, including when particular IT asset classes should be replaced.[543]

PB review

PB used benchmarking to assess if TransGrid's business IT proposals were in line with similar businesses. It reviewed TransGrid's proposals against the number of staff, the RAB at the last review, average opex and average capex.

PB's review found:

- TransGrid is intending to spend an equivalent amount on IT relative to other businesses[544]
- while processes and procedures were not being prescriptively followed, this had no material impact on investment decisions. For example, in relation to the Single sign on system not all members of the Information Technology Executive Committee[545] were consulted and signed off on the project. While 10 out of 15 Committee members responded to the request to sign off, TransGrid's IT policy indicates that projects have to be endorsed by the group.[546]
- the process for establishing the cost of IT projects is sound and the proposed expenditure is efficient.[547]

---

541 TransGrid, *Information Technology Strategy 2008*, Version 1, February 2008.
542 TransGrid, *IT Asset Management Plan*, Draft, January 2008.
543 TransGrid, *IT Management Framework*, Revision 2, August 2007.
544 PB, p. 172.
545 The Information Technology Executive Committee (ITEC) is the governing body for IT related service and investments within TransGrid and sets TransGrid's strategic direction for IT investment.
546 PB, p. 179.
547 PB, p. 179.

Consequently, PB did not recommend any adjustment to TransGrid's proposed IT expenditure. Table B.21 sets out PB's recommendation on the prudence and efficiency of TransGrid's business IT proposal.

Table B.21: PB's recommendations – business IT ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Proposal	17.9	22.9	20.3	13.2	21.7	95.9
PB's recommendation	17.9	22.9	20.3	13.2	21.7	95.9

Source: PB, p. 181.

AER assessment

Based on the documents provided by TransGrid and PB's analysis, the AER considers TransGrid has appropriate IT governance arrangements in place and the level of expenditure being proposed is efficient and reflective of a prudent TNSP in TransGrid's circumstances. While not reflective of a systemic problem, the AER has a minor concern that TransGrid has not systematically adhered to its governance policies for IT expenditure.

Based on PB's analysis and the documentation provided by TransGrid, the AER considers that the process for establishing the cost of these projects is sound, the need for investment is reasonable and that the proposed expenditure is efficient given the degree and nature of the approvals processes. The AER is therefore satisfied the expenditure on this program reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria. The AER, therefore, has not made any adjustments to TransGrid's proposed capex allowance as a result of this review.

Non-network – vehicles

TransGrid proposal

Vehicle expenditure is the second largest expenditure category within the total non-network capex. TransGrid has proposed an allowance of $31 million over the next regulatory control period. This accounts for 1.2 per cent of the initial capital allowance.

TransGrid provided some high level information on vehicles in its revenue proposal and supported this with documentation and models that detailed how purchasing decisions were made. TransGrid's motor vehicles and mobile plant are procured in accordance with procedure 'Control of motor vehicles and mobile plant – GD TR G2 001'. This policy entails:

- business/private use vehicles with associated accessories and options are only selected from the NSW government state contract list of vehicles, on the basis of fitness for purpose
- business use vehicle requirements are generally met from those vehicles available under state contract. Passenger and light commercial vehicles available under state

contract are purchased in accordance with standard procedures and vehicles are selected on the basis of:

  - suitability—selection on the basis of the vehicle's ability to perform the intended duties
  - safety—selection on the relative safety characteristics for comparable suitable vehicles
  - economics—selection of the least whole of life cost vehicle with comparable suitability and safety weighted equally with environmental impact
  - environment—selection of the vehicle with least environmental impact with comparable suitability and safety, weighted equally with economics
  - standardisation—selection of a vehicle which is in keeping with others used for similar tasks

- mobile plant, large specialised motor vehicles and motor vehicles not covered by state contract are purchased in accordance with TransGrid's purchasing business rules, which include competitive tendering.[548]

PB review

PB found TransGrid replaces vehicles under two separate structures:[549]

- business/private vehicles are replaced on an age/odometer basis—at either two years of age or 40 000 km
- business vehicles are replaced on a whole life cycle cost basis.

PB noted the contemporary whole life cycle policy was introduced in 2006, and it was, therefore, not possible to establish if the condition based replacement strategy is reducing costs. Nonetheless, PB found the policy and strategy appeared robust as new or replacement vehicle procurements require a business case.

PB also found:[550]

- the process used by TransGrid for establishing the cost of vehicle expenditure forecasts is sound
- the need for investment is reasonable
- the proposed expenditure is efficient given the degree and nature of the approvals processes.

PB recommended no adjustment be made to TransGrid's vehicle expenditure. Table B.22 sets out PB's recommendation on the prudence and efficiency of this project.

[548] PB, pp. 181−182.
[549] PB, p. 187.
[550] PB, p. 187.

Table B.22: PB's recommendations – vehicles ($m, 2007–08)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Proposal	9.3	9.3	5.9	4.6	10.0	39.1
PB's recommendation	9.3	9.3	5.9	4.6	10.0	39.1

Source: PB, p. 187.

AER assessment

Based on PB's analysis and the documentation provided by TransGrid, the AER considers that the process used by TransGrid for establishing the cost of vehicle expenditure forecasts is sound, the need for investment is reasonable and that the proposed expenditure is efficient given the degree and nature of the approvals processes. The AER is therefore satisfied that TransGrid's proposed expenditure for vehicle replacements reasonably reflects the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the capex objectives, consistent with the capex criteria. The AER, therefore, has not made any adjustment to TransGrid's proposed capex allowance as a result of this review.

Appendix C: Cost escalators

C.1 Introduction

In recent decisions for electricity TNSPs (including Powerlink, SP AusNet and ElectraNet) the AER has allowed capex and/or opex allowances to be escalated in real terms for input cost increases.[551] This involves the disaggregation of expenditure allowances into specific inputs (e.g. labour, land and materials) which are priced in terms of a base year. These base year costs are increased or decreased for each year of the regulatory control period relative to changes in the nominal price level, which is taken into account when prices and revenues are adjusted at the aggregated level under the CPI – X control mechanism.

The methodology employed to determine the cost escalators generally combines independent forecast movements in the price of input components with 'weightings' for the relative contribution of each of the components to final equipment/project costs. This in turn generates real capex and opex forecasts for the regulatory control period. The weightings are typically specific to each regulated business given differences in composition of their respective expenditure forecasts.

The underlying objective of real cost escalations was to take account of the commodities boom and skills shortages in the engineering field in Australia. In light of these external factors, it was considered that cost escalation at CPI no longer reasonably reflected a realistic expectation of the movement in some of the equipment and labour costs faced by electricity network service providers (NSPs).[552] It was also communicated by the AER at the time of allowing real cost escalations that the regime should symmetrically allow for real cost decreases.[553] This was to allow end-users to receive the benefit of real cost reductions as well as facing the cost of real increases.

Given that there is no futures market for the procurement and installation of electrical equipment (e.g. transformers, switchgear), in previous decisions cost escalations have been estimated with reference to the expected growth in key input 'cost factors' such as:

- copper
- aluminium
- crude oil
- construction costs

---

551 AER, *Decision – Powerlink Queensland transmission network revenue cap 2007-08 to 2011-12*, 14 June 2007, pp. 60-70;
AER, *Draft Decision – SP AusNet transmission determination 2008–09 to 2013-14*, 31 August 2007, pp. 87-91, 316-331;
AER, *Final Decision – ElectraNet transmission determination 2008–09 to 2012-13*, 11 April 2008, pp. 29-48..

552 NER, clause 6A.6.7(c)(3).

553 AER, *Final Decision – SP AusNet transmission determination 2008–09 to 2013-14*, January 2008, p. 80.

- electricity, gas and water (EGW) sector labour costs
- land/easement costs
- other inputs (such as steel) were escalated at CPI.

During its revenue reset process, ElectraNet engaged the Competition Economists Group (CEG) to develop forecasts for each of the cost factors and used them to escalate its proposed capex program.[554] In its final decision, the AER accepted its consultant Sinclair Knight Merz's (SKM) recommendation that CEG's proposed real cost escalators for materials are reasonable, subject to a number of adjustments.[555] In particular the AER accepted SKM's recommendations that:

- London Metal Exchange (LME) forward contract prices (i.e. 27 months) provide the best estimate of the price of aluminium and copper for a relevant future date
- monthly average futures prices should be used rather than a single day price
- Consensus Economics' 5−10 year forecasts for aluminium and copper prices represent the best available long-term forecast
- CEG's proposed adjustment to the long-term Consensus Economics aluminium and copper forecasts to reflect the higher LME futures forecast prices is not reasonable
- for the purposes of interpolation, Consensus Economics' 5−10 year forecast for aluminium and copper prices should be interpreted as the mid-point of 7.5 years, rather than 10 years as proposed by CEG.[556]

The AER has been mindful of the arguments presented and conclusions reached in its determination for ElectraNet when assessing TransGrid's proposal. This appendix presents the AER's assessment of the methodology and data sources for the proposed escalators. Where possible, the values of the escalators presented here will be updated at the time of the AER's final decision and determination.

C.2 Current proposal

As part of its revenue proposal, TransGrid engaged CEG to develop real cost escalation forecasts for the next regulatory control period.[557] For the most part CEG has maintained its methodology used to forecast aluminium, copper, crude oil prices and construction costs based on the report it prepared for ElectraNet, including its proposed adjustments to the Consensus Economics aluminium and copper price forecasts.

---

554 AER, *Final Decision – ElectraNet transmission determination,* pp. 37–39.

555 AER, *Final Decision – ElectraNet transmission determination 2008–09 to 2012-13*, 11 April 2008, pp. 29–48.

556 Consensus Economics is an international economic survey organisation. See: http://www.consensuseconomics.com/.

557 CEG, *Escalation factors affecting expenditure forecasts: a report for NSW electricity businesses*, April 2008.

The AER considers that its conclusions from the recent ElectraNet decision are still applicable with respect to the methodology used for estimating each of these cost factors (i.e. copper, aluminium and crude oil). In most cases, CEG has not presented any new compelling evidence justifying a departure from the approach previously accepted by the AER. The AER has also calculated forecasts for this draft decision using the latest available data, and intends to update this data for its final decision.

In its latest report CEG has proposed a number of additional cost factors not previously applied to the overall cost escalation methodology, including:[558]

- variances in prices charged by equipment manufacturers to reflect their market power (producer margins)
- the proportion of general labour costs used in the manufacture of electrical equipment (producer labour costs)
- indirect general labour costs associated with the processing of raw materials (e.g. steel).

The AER has concerns that these additional cost factors represent a departure from the AER's intention to account for the effects of the recent commodities boom and skilled labour shortages in Australia. The effect of their addition would be to offset the expected declines in commodities prices and the symmetry of the cost escalators envisaged by the AER. Moreover, they represent a move towards compensation for all input costs at a fine level of detail and go beyond the AER's general obligation to provide businesses a reasonable opportunity to recover efficient costs, and in this sense are also inconsistent with the incentive frameworks for capex and opex.

Notwithstanding these general concerns, the AER also considers that these additional proposed real cost factors do not meet the underlying objective for inclusion in forecast costs under clause 6A.6.7(c) of the NER. Specifically, given the inherent uncertainties around the existence and estimation of real movements in these cost factors, the AER does not consider that changes in addition to CPI are warranted. It is important to note that the AER accepts that such costs are likely to be included in base (unit) cost estimates. However, what is questionable is the extent to which real growth is expected and whether it can be forecast on a reasonable basis.

C.3 Labour cost escalators

This section discusses the real labour cost escalations proposed by TransGrid to apply to its forecast capex and opex allowances over the next regulatory control period. The proposed labour cost escalators fall into two categories:

- electricity, gas and water (EGW) or utility sector-specific labour cost forecasts
- general labour cost forecasts.

These two categories of labour costs are discussed separately below.

[558] CEG, *NSW electricity businesses*, pp. 27–38.

C.3.1 Electricity, gas and water (EGW) sector labour escalators

C.3.1.1 CEG/TransGrid

TransGrid obtained advice from CEG on forecast annual labour escalation rates for the EGW sector.

CEG relied on forecasts produced by Macromonitor and Econtech to derive its labour escalators for the EGW or utility sector in NSW. The labour cost escalators from Macromonitor and Econtech are shown in table C.1.

Table C.1: CEG's real labour cost growth rates for the EGW sector (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Macromonitor (NSW)[a]	4.2	4.4	2.3	–1.2	1.7	3.7	4.2
Econtech (AUS)	2.0	2.8	5.6	5.0	3.9	3.4	3.1

Source: CEG, *NSW electricity businesses*, April 2008, p. 7.
(a) Productivity adjusted.

The Econtech national forecasts used by CEG are based on a report to the AER for the SP AusNet and VENCorp revenue resets.[559]

The report by Macromonitor was commissioned by TransGrid, Transend and the NSW DNSPs. The Macromonitor report calculates productivity adjusted or unit labour costs for the EGW sector in NSW and Tasmania.[560]

Macromonitor noted that the actual labour cost involved with undertaking a given amount of activity is not purely determined by the rate of wages per hour, but also by the number of hours work required. Macromonitor stated that in examining the changes in an organisation's labour costs over time, a more meaningful measure than nominal wages is labour cost per unit of output, or per unit of activity. The change in this measure over time reflects both changes in wages and changes in labour productivity.[561]

Macromonitor has forecast annual productivity declines in the utility sector over the next few years which becomes positive from 2011–12. Between 2007–08 and 2013–14, Macromonitor has forecast an average annual productivity reduction of 0.7 per cent in the NSW EGW sector.[562] Macromonitor attributes the decline in productivity to a continuing upturn in the economy, together with a tight labour market and difficulties in attracting and retaining skilled staff.

CEG deflated Macromonitor's nominal labour cost escalators using its estimate of CPI to obtain the real escalators.[563] CEG also calculated real unit labour costs by

[559] Econtech, *Labour cost growth forecasts*, Attachment D.
[560] Macromonitor, *Forecasts of cost indicators*, February 2008.
[561] Macromonitor, *Forecasts of cost indicators*, p. 8.
[562] CEG, *NSW electricity businesses*, p. 10.
[563] CEG use its own CPI forecasts to deflate Macromonitor's labour cost forecast.

using Macromonitor's forecast average annual change in productivity growth for the period, rather than individual forecasts for each year. CEG derived real unit labour costs by subtracting average productivity growth from growth in real wages.[564]

CEG recommended that averaging the escalation rates calculated by Econtech and Macromonitor provides an appropriate forecast of labour cost escalators for the EGW sector in NSW. CEG did not provide any justification for averaging data from the two sources. The labour cost escalators recommended by CEG are shown in table C.2.

Table C.2: CEG's real wage growth for the EGW sectors in NSW (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
NSW	3.1	3.6	3.9	1.9	2.8	3.5	3.7

Source: CEG, *NSW electricity businesses*, p. 8.

C.3.1.2 Econtech

The AER engaged Econtech to provide advice on wage forecasts for the EGW sectors in NSW, ACT and Tasmania.[565] Econtech's labour cost growth rates for the EGW sector in NSW, the ACT and nationally are shown in table C.3.

Table C.3: Econtech's real labour escalation rates for the EGW sector (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
NSW	1.2	2.8	3.9	3.4	3.0	2.8	2.1
ACT	9.4	2.0	3.7	3.6	3.3	3.1	2.4
Australia	–0.8	2.2	3.3	3.1	2.8	2.6	2.1

Source: Econtech, *Labour cost growth forecasts*, appendix D, p. 25 and pp. 10 – 12.

Econtech determined these forecasts using an updated version of the model it developed for its report to the AER in August 2007. In particular, the forecasts provided by Econtech incorporate:

- a simplified, but enhanced approach to labour cost forecasting
- national accounts data from December 2007 (which was published by the Australian Bureau of Statistics (ABS) in March 2008)
- average weekly earnings data obtained by request from the ABS in August 2008
- policy measures introduced in the 2008–09 Federal budget

564 CEG, *NSW electricity businesses*, p. 10.

565 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, 19 September 2008. Econtech is an economic consulting firm that specialises in economic modelling, forecasting and policy analysis. Econtech merged with KPMG in August 2008.

- an extension of the forecast period from 2015–16 to 2016–17.[566]

These forecasts are broadly consistent with Econtech's national forecasts. Over the next regulatory control period, Econtech has forecast an average growth rate of 2.8 per cent (real) for the NSW utilities sector, 2.3 per cent (real) for the Tasmanian utilities sector and 3.0 per cent (real) for the ACT utilities sector. In comparison, the forecast average growth rate for the utility industry in Australia is 2.6 per cent (real).

Econtech made the following observations on the utility sectors in NSW, Tasmania and the ACT:[567]

- The forecast annual wage growth rates for the utility sectors in NSW, Tasmania and the ACT are expected to be higher than the all-industry average over the forecast period.

- The shortage of skilled workers in the utility sectors continues to be a significant driver of labour costs. Electrical and engineering professionals are included in the Department of Education, Employment and Workplace Relations 'Skill Shortage List' for NSW, Tasmania and the ACT.

- A number of initiatives have been introduced to increase the supply of skilled workers. For example, the Australian Government, through its 'Skilling Australia Policy', will provide 450 000 new training places over the next four years. However, most of these initiatives represent a long-term solution and are therefore not expected to have a material impact in the short-term.

- The Australian Government has put in place a number of initiatives to lift permanent and temporary migration. Such initiatives have the potential to relieve skills shortages in the short-term, however, there are concerns over the ability of this additional labour to meet industry demand.

- An aging workforce in the utility industry may also put further strain on the supply of skilled labour.

- The fact that electricity, gas and water are essential services means that businesses have a greater imperative to attract and maintain skilled workers, and are more likely to absorb wage increases in order to maintain labour supply.

- The utility industry has had difficulty in retaining skilled staff due to demand booms in related industries. The utility industry employs a large proportion of electricians, electrical and other engineers which are occupations also employed extensively by the construction and mining industries.

Econtech reviewed the methodology used by CEG to forecast labour cost growth rates in the EGW sector in NSW.[568] Econtech stated that CEG's approach of averaging the Macromonitor and Econtech labour cost forecasts was misguided because these forecasts were not comparable. In particular, Econtech noted:

---

566 Econtech, *Labour cost growth forecasts*, p. 4.
567 Econtech, *Labour cost growth forecasts*, pp. 22–23 and 36–37.
568 Econtech, *Labour cost growth forecasts*, pp. 38 – 42.

- The report prepared by Macromonitor does not contain any description of the methodology used to forecast wages growth, which makes it difficult to evaluate the labour cost growth forecasts produced by Macromonitor. Further, Macromonitor does not use any econometric techniques to derive its forecasts.[569]

- While reasons were put forward in the Macromonitor report to explain forecasts of productivity, there was no clear methodology provided that outlined how productivity was forecast.[570]

- Unlike the Macromonitor forecasts, the Econtech forecasts of wages growth do not remove productivity growth. Econtech's forecasts of wage growth represent the general increase in labour costs over and above inflation as well as specific compensation to labour for increases in productivity.[571] Since Econtech's forecasts incorporate compensation for increases in productivity, they are not equivalent to the Macromonitor labour cost forecasts.[572]

- The 2007 Econtech labour forecasts adopted by CEG are based on the national economy, whereas the Macromonitor forecasts are specific for NSW.[573]

C.3.1.3 AER considerations

The AER has examined the EGW wage growth forecasts put forward by CEG for NSW. Based on Econtech's advice the AER does not consider that the averaging methodology employed by CEG to forecast wages growth in the utility sectors for NSW is sufficiently robust. In particular, the AER notes Econtech's advice that the Macromonitor and Econtech forecasts are not comparable and that averaging the two forecasts is likely to provide inaccurate forecasts of labour cost escalation.[574]

In addition to the inappropriateness of averaging data from Econtech and Macromonitor, the AER does not consider that the CEG proposed labour cost growth rates are a reasonable reflection of the likely future labour costs as they are not based on the most recent information. The AER notes Econtech's advice that since it provided forecasts of labour cost growth rates to the AER in August 2007 (which were used by CEG), the economic climate has changed considerably, resulting in some pressure being taken off wages growth.[575] In particular, Econtech stated that:

> Projections of annual labour cost growth rates for overall state and territories have moderated in the past 12 months. The Reserve Bank of Australia (RBA) raised the official cash rate by 25 base points on four separate occasions since August 2007. The extent of the slowdown in household spending and credit expansion from within the household and business sector lead to the RBA to cut interest rates by 25 base points in September 2008. Despite this interest rate cut, the outlook for economic growth remains weak and the

569 Econtech, *Labour cost growth forecasts*, p. 39.
570 Econtech, *Labour cost growth forecasts*, pp. 39–40.
571 Econtech, *Labour cost growth forecasts*, p. 41.
572 Econtech's labour cost model incorporates labour productivity via the employment forecasts used in MM2 (macroeconomic model of the Australian economy). MM2 incorporates labour productivity assumptions through its own labour productivity index, PSkill. PSkill is an input into the model and not an output. MM2 also incorporates assumptions regarding the growth in labour efficiency for each industry. Labour efficiency in each industry is then used to augment PSkill.
573 Econtech, *Labour cost growth forecasts*, p. 41.
574 Econtech, *Labour cost growth forecasts*, p. 42.
575 Econtech, *Labour cost growth forecasts*, p. 24.

> unemployment rate is expected to rise over the forecast period. These factors have combined to take some pressure off wages growth at the state and national level, since the last forecasts provided to the AER in 2007.[576]

The AER also does not consider it appropriate to rely on the forecasts presented by Macromonitor because there is no description of the methodology used to forecast wages growth or productivity.

For these reasons the AER does not consider CEG's proposed labour cost growth rates for the EGW sector in NSW provide reasonable inputs to deriving the efficient costs a prudent operator in the circumstances of TransGrid would require to achieve the opex and capex objectives, as required by clauses 6A.6.6(c) and 6A.6.7(c).

The AER notes that TransGrid operates under a work place award. The AER requested TransGrid to provide the actual wage increase set out under its award. The wage increase for 2007–08 is 5 per cent.[577] The AER notes this award will expire within the next six months, thus the actual wage increase for 2008–09 is not available.

Given that the actual wage data is available for 2007–08, the AER will apply the actual wage rate provided for under TransGrid's award, and from 2008–09 onwards will apply Econtech's NSW labour cost forecasts to TransGrid's opex and capex proposals.

C.3.1.4 AER conclusions

The AER's conclusions on EGW growth rates are provided in table C.4. On average, the Econtech labour cost growth forecasts are lower than the CEG forecasts for NSW during the next regulatory control period. This is largely because the economic climate has changed considerably since the last Econtech forecasts provided to the AER in 2007, resulting in some pressure being taken off wages growth.

Table C.4: AER's conclusion on TransGrid's EGW real labour growth rates (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
AER	0.5	2.8	3.9	3.4	3.0	2.8	2.1	3.0

Source: Econtech, *Forecasts of labour cost growth forecasts*, appendix D, p. 10.
Note: The AER derived the real award rate for 2007–08 using the actual CPI for 2007–08 of 4.5 per cent. The average is calculated for 2009–10 to 2013–14 (the next regulatory control period).

The AER considers that the application of the Econtech forecasts for wages growth in the EGW sector for NSW reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex and capex objectives, as required by clauses 6A.6.6(c) and 6A.6.7(c).

[576] Econtech, *Labour cost growth forecasts*, p. 24.
[577] TransGrid, response to AER request for information, confidential, 17 September 2008. Note that the AER derived the real per cent increase using the actual CPI for 2007–08 of 4.5 per cent.

C.3.2 General labour escalators

C.3.2.1 CEG

CEG recommended that TransGrid apply Econtech's forecast for wages across the Australian economy as an appropriate estimate of general labour costs. The general labour cost forecast recommended by CEG is taken from Econtech's Australian National State and Industry Outlook (ANSIO) December 2007 report and is outlined in table C.5.

Table C.5: CEG's real general wage growth (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
General wage	1.8	1.6	2.4	1.9	1.8	2.0	2.0

Source: CEG, *NSW electricity businesses*, p. 31.

TransGrid has applied CEG's recommended general labour escalator to aspects of its capex proposal, to account for real cost increases for more generic categories of direct labour.

TransGrid also applied the CEG forecast for general wages to escalate specific components of its capex, to account for real cost increases for indirect labour associated with manufactured equipment.

CEG recommended that TransGrid apply the Econtech general wage cost to escalate equipment cost inputs (incurred by equipment manufacturers) for the next regulatory control period.[578] CEG stated TransGrid could face higher equipment costs due to increased producers' wage costs and that these indirect labour costs should be recoverable under the AER's regulatory framework.

CEG produced its estimates for producer labour costs using the ABS input-output tables.[579] These tables examine the supply and use of goods and services in the Australian economy by identifying the inputs (including employee compensation) used by a particular industry relative to defined outputs. All the data in the ABS input-output tables are specific to the Australian economy.

CEG stated that it has:

> …estimated the proportion of inputs associated with labour in each relevant industry by calculating the ratio of the compensation of employees against the combined sum of this and the total value of production.[580]

CEG calculated the proportion of labour used to produce each relevant ABS output category to be 27 per cent.[581] The categories examined were:

- primary plant and materials supply

[578] CEG, *NSW electricity businesses*, p. 31.
[579] ABS, *Australian National Accounts: Input-Output Tables 2001/02*, Cat no: 5209.0.55.001, Table 2.
[580] CEG, *NSW electricity businesses*, p. 30.
[581] CEG, *NSW electricity businesses*, p. 31.

- secondary systems and materials supply
- transformers
- aluminium conductor
- copper cable/conductor.

CEG then recommended using Econtech's Australian general wage cost forecasts to escalate the labour component of the above equipment categories over the next regulatory control period.

C.3.2.2 AER considerations—direct labour costs

The AER accepts that a general labour cost forecast is appropriate to escalate direct labour costs (i.e. other than EGW) incurred by NSPs.

As part of its report to the AER, Econtech also provided advice on general wage forecasts for all industries across Australia. A comparison of Econtech's general wage forecast with the forecasts recommend by CEG is shown in table C.6.

Table C.6: CEG and Econtech's real labour escalators for general wages (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
CEG	1.8	1.6	2.4	1.9	1.8	2.0	2.0	2.0
Econtech	0.6	1.0	1.1	0.7	0.7	0.8	0.6	0.8

Source: CEG, *NSW electricity businesses*, p. 31;
Econtech, *Forecasts of labour cost growth forecasts*, p. 25.
Note: The average is calculated for 2009–10 to 2013–14.

As can be seen from table C.6 there is a material difference between the general wage forecasts provided by CEG and Econtech's general wage forecasts.

The AER notes that the general wage forecasts used by CEG were taken from Econtech reports published in 2007. Econtech stated that, since it provided forecasts of labour cost growth rates to the AER in August 2007, the economic climate has changed considerably.[582]

The AER notes that Econtech's latest ANSIO for June 2008 also predicts a decline in average earnings for general wages.[583]

Given the change in economic conditions since 2007, the AER does not consider that the general wage forecasts proposed by CEG are reasonable for the purposes of forecasting efficient input costs for the next regulatory control period required to meet the capex and opex objectives.

[582] Econtech, *Labour cost growth forecasts*, p. 5.
[583] Econtech, *Australian National, State and Industry Outlook*, 22 July 2008, p. 110.

Accordingly, where applicable the AER will apply Econtech's latest general wage forecasts to TransGrid's capex proposal.

C.3.2.3 AER conclusions—direct labour costs

The AER's conclusion on a general labour cost escalator is set out in table C.7.

Table C.7: AER's conclusion on real general wage growth (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
AER	0.6	1.0	1.1	0.7	0.7	0.8	0.6	0.8

Source: Econtech, *Forecasts of labour cost growth forecasts*, p. 25.

C.3.2.4 AER considerations—indirect labour costs

The AER notes that TransGrid has applied the Econtech labour cost escalator to equipment cost inputs. This is intended to represent the labour costs incurred by the producers of manufactured equipment that is purchased by NSPs.

The AER notes CEG's proposal to weight general labour costs at 27 per cent of the total costs of various electrical equipment. As noted in section C.2 of this appendix, the AER considers that the introduction of a labour component in equipment costs is inappropriate as it is:

- represents a movement beyond the AER's obligation to provide regulated businesses a reasonable opportunity to recover efficient costs towards providing compensation for changes in input costs at a very fine level of detail. The AER considers it sufficient to monitor whether the cost of finished goods, as opposed to the component parts, need to be escalated above or below CPI
- not supported by robust data.

The AER notes that some amount of producers' labour costs will already be embedded in the NSPs' base cost estimates of equipment (i.e. as at 30 June 2007). However, what is questionable is the extent to which the existing producers' labour costs embedded in base costs are expected to change in real terms over the next regulatory control period, and if a real change is expected, how to reliably measure it.

The data used by CEG assumes that Australian manufacturing conditions (as measured in the ABS input-output tables) and wage growth rates are the same as in those countries where equipment is purchased from. It also assumes that labour and other factor productivity is held constant. These issues have not been addressed by CEG to substantiate its recommended position.

C.3.2.5 AER conclusions—indirect labour costs

The AER does not accept the producer wage cost escalator proposed by CEG as it does not meet the underlying objective for inclusion in forecast costs under clause 6A.6.7(c) of the NER. On the basis of the information presented, the AER is not satisfied that expenditure associated with a real escalation of indirect labour costs is required to meet the capex objectives.

C.4 Land/easement cost escalators

This section discusses the real land/easement cost escalations proposed by TransGrid to apply to forecast capex and/or opex allowances over the next regulatory control period.

C.4.1 TransGrid

TransGrid obtained advice from CEG on forecast movements for land prices in NSW.[584] CEG based its average real annual escalation forecasts on estimates supplied by BIS Shrapnel.[585] CEG forecast 4.1 per cent per annum for both Sydney CBD B Grade[586] and non-CBD B Grade[587] properties.

CEG noted the difficulty in predicting annual changes in real estate growth, given the variability with investors' perceptions of expected growth in rental prices. Further, CEG noted the difficulty in forecasting real estate growth over widespread areas in which TransGrid operates.

TransGrid further commissioned Jones Lang LaSalle (JLL) to provide advice on land value escalation factors for 2008 to 2013.[588] JLL determined forecasts for the Sydney metropolitan region have a range of 5–10 per cent (nominal) and recommended an escalator of 6 per cent per annum. JLL further forecast non-metropolitan regions are expected to increase at a rate greater than metropolitan properties, having a range of 7–13 per cent (nominal). JLL recommended a more conservative level at the lower end of 9 per cent per annum be adopted for non-metropolitan areas.

CEG noted that its forecasts of 4.1 per cent are consistent with advice from JLL (when factoring in inflation to the real escalators proposed by CEG). Therefore, CEG concluded that adopting an average annual escalation factor of 4.1 per cent provides an appropriate estimate for land values in NSW.

The escalators recommended by CEG for land movements are outlined in table C.8.

Table C.8: CEG's real land escalators for NSW (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Land	4.1	4.1	4.1	4.1	4.1	4.1	4.1

Source: CEG, *NSW electricity businesses*, p. 1.

C.4.2 AER considerations

The AER notes that CEG did not outline a transparent methodology to derive its average land value escalators. Further, CEG's recommended average annual land escalators for Sydney CBD B Grade and non-CBD B Grade property of 4.1 per cent

584 CEG, *NSW electricity businesses*, pp. 40–41.
585 BIS Shrapnel, *Sydney Commercial Property Prospects 2007 – 2021*, May 2007.
586 B Grade property refers to non-price property, eg, land not typically suited for retail or office development.
587 Non-CBD B Grade property is based on the average forecast for North Sydney, Chatswood, Parramatta and North Ryde.
588 Jones Lang LaSalle, *Revenue Reset Program – Land Value Growth Factors*, January 2008.

(in real terms) is based on nominal estimates provided by BIS Shrapnel. The BIS Shrapnel report did not provide a clear methodology that it used to derive estimates and did not include non-CBD B Grade property data.

In previous transmission determinations, the AER utilised ABS long-term historical land data to develop forecast proxies for land and easement escalation rates.[589] The AER considers the use of a long-term historical average as a reasonable forecast due to long-term data being less exposed to business cycle fluctuations. Therefore, to test the appropriateness of the forecast land escalators proposed by CEG, the AER considered NSW land value data published by the ABS, using its entire data series (1989–2007).[590] The AER derived an equal weighted average rate based on NSW land types published by the ABS (residential, commercial and rural), deflated by CPI to calculate a real growth rate that is generally consistent with that recommended by CEG.

Based on the long-term historical trends of land value growth published by the ABS, the AER considers that the proposed average land/easement escalator of 4.1 per cent provides a reasonable measure of forecast real land value growth expected in NSW.

C.4.3 AER conclusions

The AER's conclusions on the real land escalators for NSW are set out in table C.9.

Table C.9: AER's conclusion on real land escalators for NSW (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
NSW	4.1	4.1	4.1	4.1	4.1	4.1	4.1

C.5 Materials cost escalators

This section discusses the real materials cost escalators proposed by TransGrid to apply to its forecast capex proposal over the next regulatory control period. The proposed materials cost escalators are as follows:

- copper and aluminium
- steel
- crude oil
- exchange rates (used to develop the materials cost escalators)
- producer margins
- construction costs (includes labour and materials costs).

589 AER *Draft Determination Powerlink revenue cap*, p. 76.
AER, *Draft decision – SP AusNet transmission determination*, pp. 189–190.
AER, *Final Decision – ElectraNet transmission determination*, p. 34.

590 ABS, *Australian System of National Accounts, 2006-07*, Cat No: 5204.0, Table 83.

These cost escalators are discussed separately below.

C.5.1 Aluminium and copper

C.5.1.1 ElectraNet transmission determination

Following the AER's draft decision which rejected ElectraNet's non-labour (materials) cost escalators, ElectraNet engaged CEG to develop forecast materials cost escalators for its capex program.

In determining escalators for aluminium and copper, CEG used London Metal Exchange (LME) actual and futures prices of these base metals for the period up to June 2009. From this point CEG determined forecasts through a straight-line interpolation between the latest available LME forecast and Consensus Economics' long-term forecast. The Consensus Economics' long-term forecast used in this calculation was adjusted by CEG to reflect the difference between the forecast for April 2010 (as implied by the 27-month LME futures price as at January 2008) and the mean Consensus Economics forecast for March 2010—an approach CEG considered to be consistent with the view that futures prices provides the most reliable forecasts of metals prices.[591]

SKM, in its final report for the AER, commented that applying an upward adjustment to Consensus Economics' long-term forecasts detracts from the economic assumptions made by forecasters and that they would have considered the latest market information (such as LME forward contracts) in their forecasts.[592] SKM consequently recommended that the upward adjustments be removed from the calculation of escalators for aluminium and copper.

In its final decision the AER accepted SKM's recommendation to not adjust Consensus Economics' long-term aluminium and copper price forecasts. It also accepted SKM's recommendations that:

- LME forward contract prices provide the best estimate of the price of aluminium and copper for a relevant future date
- a monthly average futures price be used rather than the single day futures price
- the interpolation of the Consensus Economics' long-term price forecast should be to the mid-point of 7.5 years, rather than 10 years.

For further discussion of these issues see chapter 3 of the AER's final decision for ElectraNet.[593]

C.5.1.2 CEG/TransGrid

TransGrid engaged CEG to develop aluminium and copper cost escalators. CEG used two data sources to develop its aluminium and copper price forecasts:

[591] In this case, CEG adjusted Consensus Economics' long-term forecasts for aluminium and copper by 9 per cent and 18 per cent respectively.
[592] SKM, *ElectraNet Transmission Network Revised Revenue Proposal 2008-2013*, 24 April 2008.
[593] AER, *Final Decision – ElectraNet transmission determination*, 11 April 2008.

- LME actual prices to March 2008, then forward contracts (3, 15 and 27 months) for short-term price forecasts out to June 2010
- Consensus Economics long-term price forecasts from July 2010 to 2017.

The Consensus Economics report provides a single mean price forecast of long-term aluminium and copper prices (among other commodities), which it developed from a survey of over 20 commodity price forecasters. As with the report it prepared for ElectraNet, for the purposes of data interpolation, CEG has defined the 'long-term' to be 10 years, being the end point of the 5 to 10 year period defined as 'long-term' by Consensus Economics.

To merge the LME forward contract price forecasts with Consensus Economics' long-term forecasts, CEG interpolated the LME forecasts as at June 2010 with an adjusted Consensus Economics' long-term forecast. As with the report it prepared for ElectraNet, CEG observed that the Consensus Economics' forecasts were lower than the LME 27-month forward contract price in the period out to June 2010 by an average of 21 per cent and 30 per cent for aluminium and copper respectively. Subsequently, CEG scaled up Consensus Economics' long-term forecast by these percentage differences.[594]

CEG's proposed real copper and aluminium cost escalators for the 2007–14 period are presented in table C.10.

Table C.10: CEG's proposed real cost escalators for copper and aluminium (per cent)

	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
Copper	–0.4	–3.7	–6.3	–4.2	–2.8	–3.1	–3.1
Aluminium	–5.6	3.5	–0.5	–0.2	0.3	0.0	0.0

Source: CEG, *NSW electricity businesses*, p. 1.

C.5.1.3 AER considerations

The AER considers that a linear interpolation between the LME forecasts and the Consensus Economics' long-term forecast appears to be the most reasonable approach to merge the short-term LME data with Consensus Economics long-term forecasts. The AER does not, however, consider that an upward adjustment (21 per cent and 30 per cent for aluminium and copper respectively) to Consensus Economics' data prior to interpolation is appropriate. Interpolation between these two data sources, without adjustment of Consensus data, is the same methodology approved by the AER in its determination for ElectraNet. The AER considers this methodology provides reasonable estimates of efficient cost inputs that the NSW DNSPs require to achieve their capex and opex objectives.

In the ElectraNet revenue reset process, the AER engaged SKM to review and provide advice on CEG's methodology. SKM provided a number of reasons why Consensus

[594] CEG, *NSW electricity businesses*, p. 17.

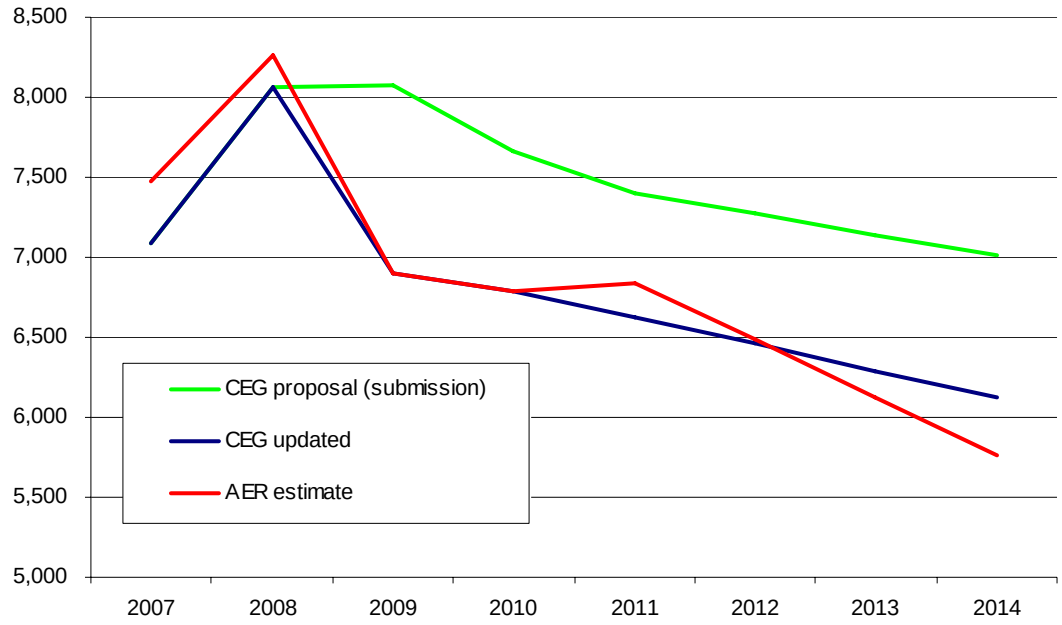
Economics' long-term forecasts should not be adjusted in accordance with the CEG proposal:

> … the assumption that the experienced forecasters developing the various predictions that constitute the long-term Consensus Economics prices, would be well aware of 27 month LME prices, and principles of linear interpolation, yet still chose to predict long-term prices at the levels presented.
>
> … CEG's adjustment, based on the difference between the LME 27 month contract price and the corresponding Consensus Forecast of the spot price 27 months out, is highly dependent on the volatility presented within the 27 month LME price. This methodology would therefore determine that the magnitude of the adjustment to the Consensus long term forecast prices would be subject to significant variations, depending on the specific date on which the 27 month LME price was sourced.[595]

The AER has therefore developed its own projections using LME futures prices up to 2010 and Consensus Economics' long-term (7.5 years) forecast, then interpolating between the two data sources.

The AER's updated (as at September 2008) estimates for copper and aluminium price forecasts are shown alongside CEG's proposed approach (based on January 2008 and updated August 2008 data) forecasts in figures C.1 and C.2.[596]

Figure C.1: AER's estimate and CEG's proposal on forecast copper price ($US/tonne, nominal)

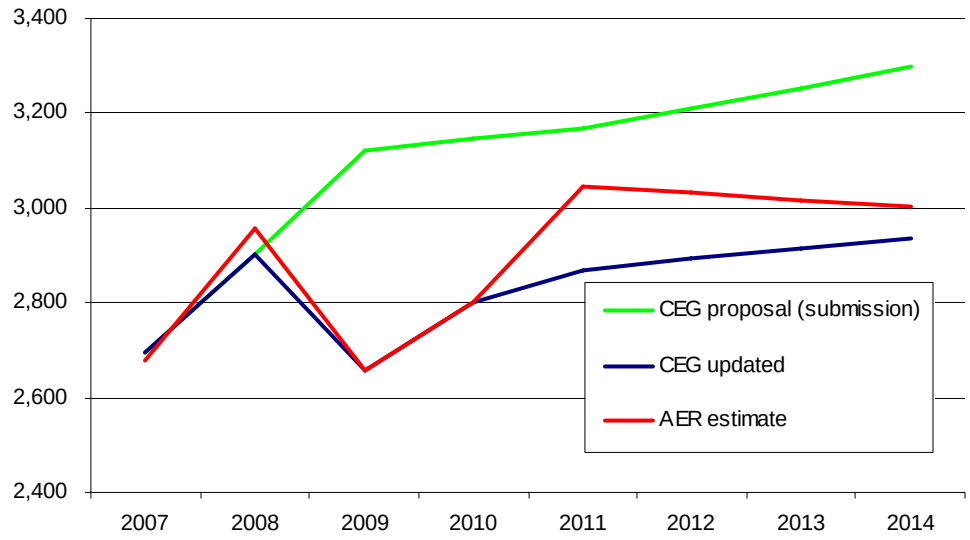


Source: CEG, *NSW electricity businesses*, pp. 11–17; AER analysis.

595 SKM, *ElectraNet Transmission Network Revised Revenue Proposal*, p. 38.

596 Note that figures 3 and 4 are in $USD prices/tonne to avoid complications associated with exchange rate movements. In $USD the individual impact of new data and the removal of the CEG adjustment can be more easily illustrated.

Figure C.2: AER's estimate and CEG's proposal on forecast aluminium price ($US/tonne, nominal)



Source: CEG, *NSW electricity businesses*, pp. 17–19; AER analysis.

As figures C.1 and C.2 illustrate, copper and aluminium price forecasts have decreased since CEG's proposal was made. For comparative purposes the AER has calculated the CEG forecasts using updated data. The difference between the 'AER estimate' and 'CEG updated' series over 2010–14 reflects the key difference in methodology, with the AER not escalating the Consensus Economics long-term forecast to reflect the difference between that forecast and LME futures prices.

The AER also assumes the mid-point (7.5 years) for Consensus Economics' long-term forecast, rather than the end point (10 years) as proposed by CEG.

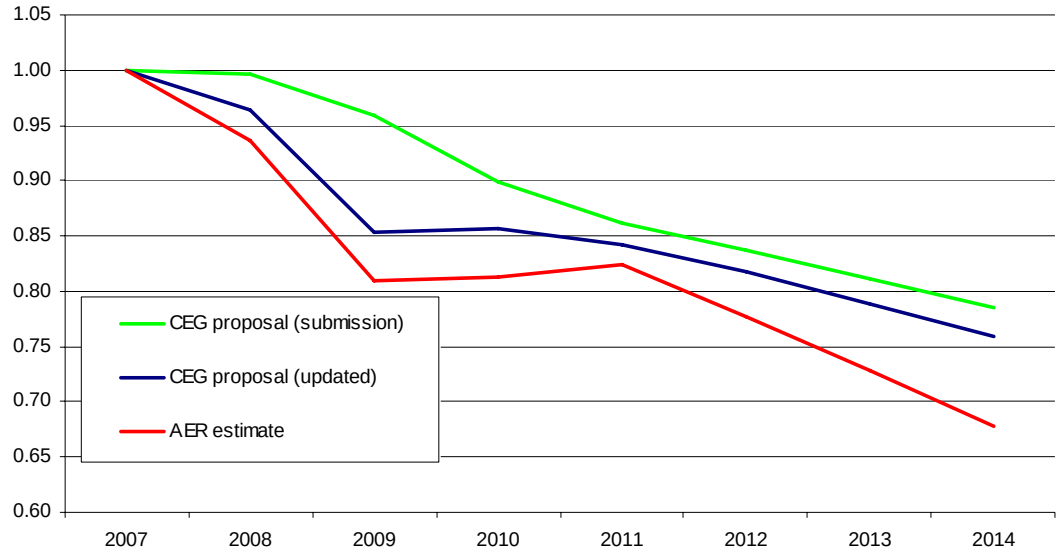
Since all aluminium and copper prices from LME and Consensus Economics were in nominal US dollar (USD) terms, all the projections were converted into nominal Australian dollars (AUD) using the following steps:

- convert nominal USD to nominal AUD using the RBA's latest actual and Econtech's forecast exchange rates[597] (see section A.5.4)
- convert nominal AUD to real AUD June 2009 using actual and forecast CPI based on the AER's methodology[598]
- convert into a real cost escalation index (with a base year of 30 June 2007).

The conversion to real AUD has quite a substantial impact on the results, as shown in figures C.3 and C.4.

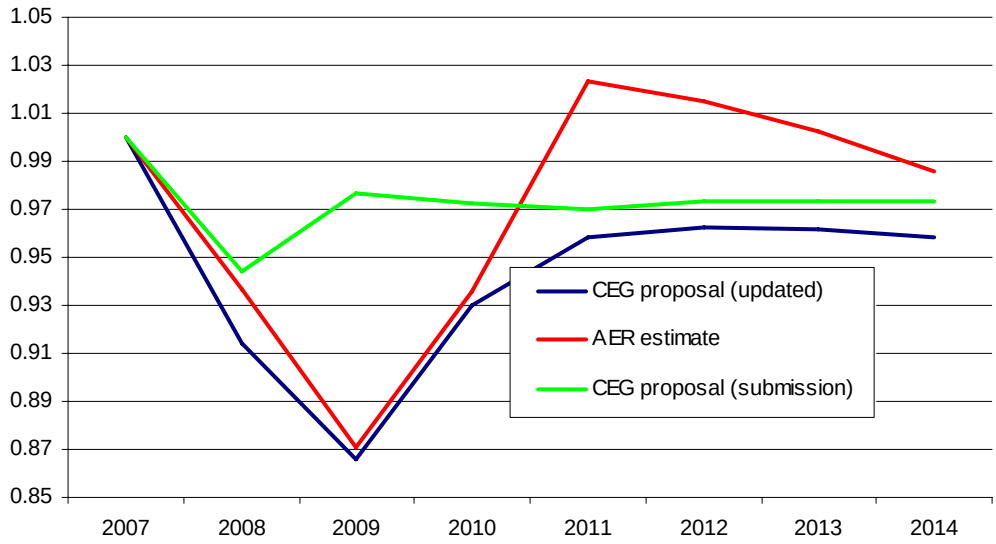
[597] Econtech, *ANSIO*, 22 July 2008.
[598] RBA, *Statement on Monetary Policy*, August 2008 and http://www.rba.gov.au/Statistics/measures_of_cpi.html.

Figure C.3: AER's estimate and CEG's proposal on copper cost escalators (index, real $AUD/tonne June 2009, base year = 2007)



Source: CEG *NSW electricity businesses*, pp. 11–17; AER analysis.

Figure C.4: AER's estimate and CEG's proposal on aluminium cost escalators (index, real $AUD/tonne June 2009, base year = 2007)



Source: CEG, *NSW electricity businesses*, pp. 17–19; AER analysis.

In accordance with its preference to use updated data where possible and based on the methodology applied in this draft determination, the AER will incorporate updated LME and Consensus Economics data for its final determination.

C.5.1.4 AER conclusions

The AER is not satisfied that the methodology recommended by CEG and relied upon by TransGrid reflects a realistic expectation of input costs required to meet the capex and opex objectives, over the next regulatory control period.

The AER considers it is appropriate to forecast copper and aluminium prices by using LME futures prices up to 2010 and the long-term Consensus Economics forecast (7.5 years), then interpolate between the two data sources. However, adjusting the long term price of copper and aluminium by the difference between the LME 27–month forward contract price and the corresponding Consensus Economics long-term forecast is inappropriate and unnecessary.

Based on September/October 2008 data for this draft determination, the AER's conclusions on real copper and aluminium escalators for the 2007–14 period using this methodology are presented in table C.11. The AER will use updated LME and Consensus Economics data for its final determination.

Table C.11: AER's conclusions on real copper and aluminium cost escalators (per cent)

	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
Copper	–6.3	–13.5	0.3	1.4	–5.6	-6.3	–7.0
Aluminium	–6.3	–7.0	7.5	9.3	–0.8	–1.3	–1.6

C.5.2 Steel

C.5.2.1 CEG/TransGrid

CEG stated that because there is currently no futures market for 'mill gate' steel to forecast steel prices, it has relied on Consensus Economics short and long-term price forecasts for hot rolled coil (HRC) steel traded in the US and in Europe.[599] CEG took the average of the US and European long-term forecasts over the 5 to 10 year horizon, which produced a forecast average decrease in real HRC prices of 11 per cent over next 10 years. CEG considered the long-term should be interpreted as 10 years and, based on this assumption, forecast an average annual real price reduction of 1.2 per cent for HRC steel.[600]

CEG then used ABS input-output data to derive the cost contribution of materials and inputs used by producers that transform HRC steel into products for use by Australian NSPs. CEG looked at three types of fabricated steel products, and derived the average weighting of 'iron and steel' content as 14 per cent and 'employee compensation' as 26 per cent of fabricated steel, by cost.[601]

CEG has applied its HRC real escalator of –1.2 per cent to the iron and steel component (weighted at 14 per cent), and adopted an Econtech general wage (real) growth forecasts from December 2007 for the employee compensation component (weighted at 26 per cent). The CEG methodology assumes that all other cost components (weighted at 60 per cent) of the fabricated steel product would remain unchanged in real terms. Table C.12 sets out CEG's recommended real escalators for steel products, as derived using the weighted input components discussed above.

599 Consensus Economics, *Energy & metals consensus forecasts: Minerals Monitor*, 28 January 2008.
600 CEG, *NSW electricity businesses*, p. 1.
601 CEG sourced these data from ABS catalogue No 5209.0.55.001. The three types of steel products categories referenced are structural metal products, sheet metal products and fabricated metal products.

Table C.12: CEG's proposed real escalators for steel products (per cent)

	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
Steel products	0.2	0.1	0.3	0.2	0.2	0.2	0.2

Source: CEG, *NSW electricity businesses*, p. 1.

C.5.2.2 AER considerations

The AER has concerns with the derivation of CEG's fabricated steel escalator and considers the approach should be modified to be consistent with the escalators used for other base metals such as copper and aluminium. The AER's reasoning and subsequent amendments to the CEG methodology, and the resulting steel escalator, are set out below.

HRC steel component

The Consensus Economics estimates applied by CEG are derived from commodity price forecasters' long and short-term HRC steel price expectations for trading in the US and European markets. The AER accepts that CEG's reliance on US and European forecasts may not produce an ideal forecast for the cost of fabricated steel used in the production of equipment purchased by NSPs, as this may be sourced from other markets. However, in the absence of more geographically accurate forecasts, the AER considers that the averaging of the US and European long-term market forecasts results in a reasonable approximation for the future price of HRC steel that affects the costs faced by Australian NSPs. The AER will reconsider the appropriateness of using these data should an alternative source arise in the future.

The AER notes that the updated Consensus Economics data reports price expectations in Europe relative to metric tonnes whilst those in the US represent 'short tons'.[602] This difference does not appear to have been noted by CEG in its original analysis. To allow meaningful average future price movements to be derived from these two data sets, the AER has scaled the US short ton data to metric tonnes, before taking the average of both series.

The AER has obtained the most recent Consensus Economics HRC steel price forecasts[603] and has recalculated the HRC component escalator, using the methodology set out in CEG's report, but taking the long-run forecast to represent 7.5 years for the purposes of data interpolation. This is consistent with the assumption that a 5 to 10 year horizon is reflective of the long-term, of which 7.5 years is the mid point. For the period to 2007–08 the AER has obtained Bloomberg historical data on HRC steel prices in the US and Europe.

As figure C.5 illustrates, HRC steel prices have increased significantly since 2007 and are expected to peak in 2008 before declining over the next regulatory control period. Table C.13 sets out the AER's updated actual and forecast HRC steel prices.

602 A metric tonne is equivalent to 1.1023 short tons.
603 Consensus Economics, *Energy & metals consensus forecasts: Minerals Monitor*, 28 July 2008.

Figure C.5: AER's estimate of HRC steel prices (real AUD/metric tonne, June 2009)

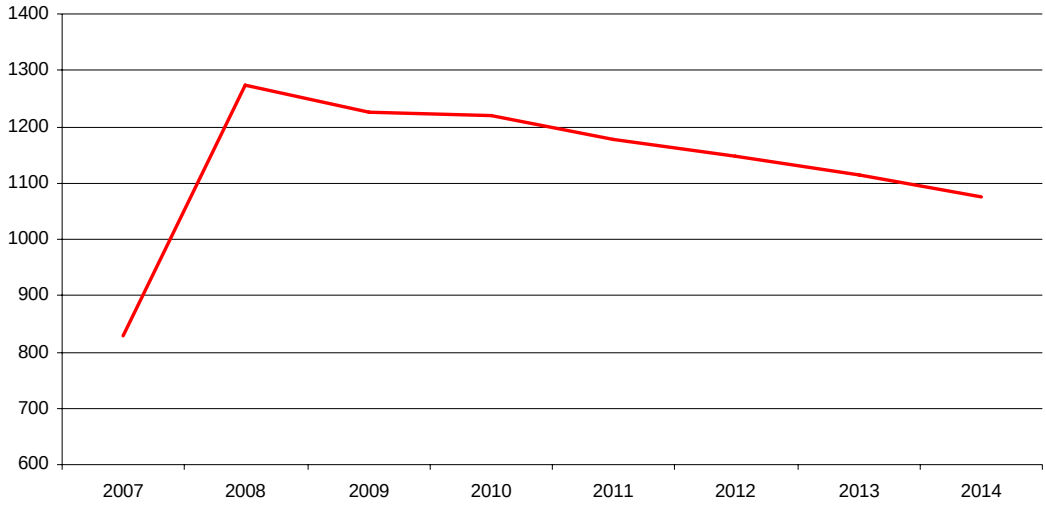


Table C.13: AER's estimate of real HRC steel prices (AUD/metric tonne)

	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
HRC prices	827.6	1273.3	1225.6	1218.89	1177.3	1147.9	1113.5	1075.7
% change		53.8	–3.7	–0.6	–3.4	–2.5	–3.0	–3.4

Source: Consensus Economics, June 2008; AER analysis.
Note: Average of US and European HRC contract prices.

Labour and 'other' components

CEG has incorporated a labour component into its estimate of fabricated steel escalators, weighted at 26 per cent of production cost. CEG has assumed that this cost component will experience positive real growth during the next regulatory control period. The rate of this growth has been estimated using Econtech's general wage forecasts across the Australian economy.[604]

The remaining input cost components of fabricated steel identified by CEG include profits margins and taxes. These are weighted at 60 per cent by input cost and are assumed to remain constant in real terms in the calculation of the CEG fabricated steel escalator.[605]

CEG has used Australian ABS input-output tables to derive the proportion of labour costs in fabricated steel production in Australia. The AER's considerations on the CEG methodology for applying a producers' labour input cost component to manufactured goods are set out above in section C.3.2.4 and are also applicable in the case of steel manufacturing. The AER has concerns about the introduction of this type of cost escalation factor, and also notes that CEG has not substantiated that the Australian input-output and wage data presented is relevant to its claims. Accordingly the AER does not accept CEG's proposed labour cost component for steel.

[604] CEG, *NSW electricity businesses*, p. 31.
[605] CEG, *NSW electricity businesses*, p. 29.

CEG has developed escalators for other base metals such as copper and aluminium, and has relied on the prices of less processed inputs as proxies for copper and aluminium products used in equipment purchased by NSPs. The AER considers the same approach should be applied for fabricated steel, and has decided to use the most recent long-term Consensus Economics HRC steel forecasts as a proxy for changes in the price of fabricated steel, weighted at 100 per cent. This therefore removes the distinction between CEG's proposed input components to the fabricated steel escalator and simplifies the derivation of the escalator, which is consistent with the approach to forecasting other metals cost escalators.

C.5.2.3 AER conclusions

The AER is not satisfied that the methodology for forecasting steel prices, including recognition of indirect labour, profits and taxes in these prices, recommended by CEG and relied upon by TransGrid reflects a realistic expectation of input costs over the next regulatory control period.

For this draft decision the AER has obtained updated Consensus Economics HRC steel price forecasts and has recalculated the HRC component escalator taking the long-run Consensus forecast to represent 7.5 years for the purposes of data interpolation. For the period to 2007–08 the AER has obtained Bloomberg historical data on HRC steel prices in the US and Europe. For its final decision and determination the AER will consider the use of latest data under this methodology.

The AER's draft decision on TransGrid's proposed real steel cost escalators for the next regulatory control period is set out in table C.14.

Table C.14: AER's conclusion on real fabricated steel escalators (per cent)

	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
AER	53.8	–3.7	–0.6	–3.4	–2.5	–3.0	–3.4

C.5.3 Crude oil

C.5.3.1 CEG/TransGrid

CEG stated that the New York Mercantile Exchange (NYMEX) crude oil light futures price is a reliable predictor of future crude oil prices.[606]

The escalations are calculated using:

- US Department of Energy for historical data to June 2007
- the NYMEX crude oil light futures data, converted to Australian dollars (AUD) using Reserve Bank of Australia (RBA) historical exchange rate data and the AUD/US exchange rate forecast from the Econtech 2007 ANSIO report.

CEG has proposed (based on data downloaded on 6 January 2008) escalation rates for crude oil set out in table C.15.

606 CEG, *NSW electricity businesses*, p. 25.

Table C.15: CEG's proposed real escalators for crude oil ($nominal)

	2006-07	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
USD prices	60.0	85.3	99.4	96.9	96.5	97.0	96.3	96.7
% change		42.2	16.6	–2.5	–0.5	0.5	–0.7	0.5
AUD price	76.3	97.8	112.9	111.2	112.4	114.6	115.1	116.9
% change		28.1	15.4	–1.4	1.0	2.0	0.5	1.5

Source: CEG, *NSW electricity businesses*, p. 25.

C.5.3.2AER considerations

In its recent ElectraNet transmission determination, the AER accepted CEG's proposed data sources and considered that they can be used to provide reliable estimates of both actual and forecast crude oil price escalators.[607] The AER remains of this view and maintains its position that the NYMEX crude oil light futures prices should be averaged over 20 trading days to remove day-to-day volatility.

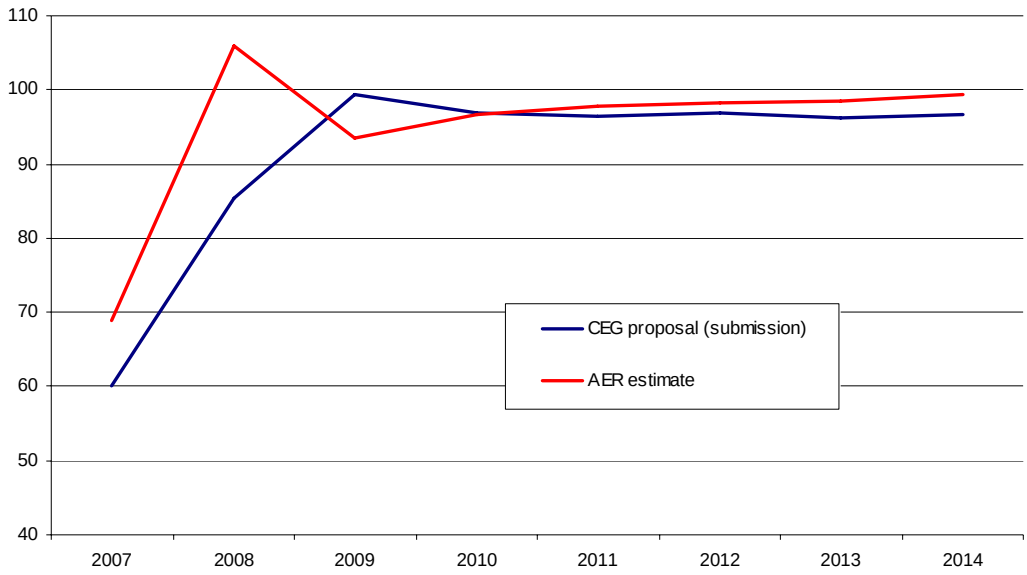
The AER has taken a 20-day average of daily NYMEX crude oil light futures prices, which results in updated crude oil forecasts.[608] The AER's updated estimate of crude oil prices ($US/barrel, nominal) is presented alongside CEG's proposed estimates in figure C.6.

As figure C.6 indicates, crude oil futures prices are relatively unchanged since the CEG report.

The AER converted the NYMEX forecasts into real Australian dollars using Econtech's forecast exchange rate (see section C.5.4), and the AER's methodology for forecast CPI (see chapter 4).

[607] AER, *ElectraNet final decision*, pp. 42–45.
[608] The AER's sample period was between 22 September and 17 October 2008.

Figure C.6: AER's estimate of crude oil prices ($US/barrel, nominal)



C.5.3.3 AER conclusions

The AER considers that the 20 day average of NYMEX crude oil light futures prices produces forecasts that reflect a realistic expectation of input costs, required to meet the capex and opex objectives over the next regulatory control period. In accordance with the AER's preference to use the most recent data where possible, the AER's final determination will incorporate updated NYMEX data when the determination is published in April 2009.

Using data published at the time of this draft decision, the AER's conclusion on crude oil escalators is set out in table C.16.

Table C.16: AER's conclusion on real crude oil (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
AER	43.5	–13.4	1.5	1.7	0.1	–0.6	–0.1

C.5.4 Exchange rate

C.5.4.1 CEG/TransGrid

CEG proposed using Econtech's 2007 ANSIO report forecast of AUD/USD exchange rates, as set out in table C.17.

Table C.17: CEG's proposal on AUD/USD exchange rate forecast, as at 1 July

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
AUD per USD	0.85	0.88	0.88	0.87	0.85	0.84	0.83

Source: CEG, *NSW electricity businesses*, p. 40.

C.5.4.2 AER considerations

The AUD/USD exchange rate forecasts are used to convert escalators based on futures/market prices (e.g. crude oil, steel prices etc) which are only quoted in US dollar terms.

Exchange rates are a particularly volatile economic variable, driven by numerous factors and are consequently notoriously difficult to forecast both in the short, medium and long-term. While the AER accepted the use of an Econtech exchange rate forecast in its recent ElectraNet transmission determination, it notes that the potential volatility of exchange rates brings any single source of forecast into question.

Table C.18 sets out Econtech's June 2008 AUD/USD exchange rate forecast.

Table C.18: Econtech's AUD/USD exchange rate forecast, as at 1 July

	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
AUD per USD	0.85	0.96	0.88	0.84	0.82	0.80	0.75

Source: Econtech, *Australian National State and Industry Outlook*, 22 June 2008, p. 110.

Events in recent months demonstrate the volatility of exchange rate movements, with the AUD/USD exchange rate peaking at US$0.98 on 16 July 2008 before falling back (by 42 per cent) towards US$0.69 on 17 October 2008. The peak in July was heavily influenced by positive sentiment towards the AUD driven by Australian/US interest rate differentials, strong commodity prices, the downturn in the US economy, housing market and US bank write-downs. The recent reduction resulted from negative sentiment on the AUD stemming from reductions in official interest rates and slowing commodity price growth.

The exchange rate forecasts proposed by both CEG and SKM from Econtech use forecasts of an exchange rate at five points in time only through the next regulatory control period—that is, the exchange rate on 1 July of each year. However, irrespective of the accuracy of the Econtech's exchange rate forecasting, the very nature of a point in time forecast, particularly in a volatile market, is not necessarily likely to be representative of the AUS/USD exchange rate faced by businesses purchasing equipment throughout the next regulatory control period.

The AER notes that there is little apparent difference between Econtech's latest forecasts and those used as part of TransGrid's proposal and will rely on the Econtech forecasts. As current exchange rates have moved significantly since TransGrid submitted its proposal the AER will take account of the actual exchange rate at the time of its final decision and determination in 2009.

C.5.4.3 AER conclusions

The AER considers that an exchange rate forecast prepared by Econtech at the time of the final decision will represent a realistic expectation of forecast exchange rates over the next regulatory control period. Using more recent data from this source, the AER's conclusion on the AUD/USD exchange rate forecast for this draft decision is

set out in table C.19. The AER will obtain updated data from this source for its final determination.

Table C.19: AER's conclusion on AUD/USD exchange rate forecast, as at 1 July

	2007−08	2008−09	2009−10	2010−11	2011−12	2012−13	2013−14
AUD per USD	0.85	0.96	0.88	0.84	0.82	0.80	0.79

Sources: Econtech, *Australian National State and Industry Outlook*, 22 June 2008, p. 110.

C.5.5 Producer's margin

C.5.5.1 CEG/TransGrid

CEG has recommended that TransGrid apply a producer's margin to escalate equipment cost inputs for the next regulatory control period.[609]

CEG proposed that this is a legitimate cost that NSPs could face in the current economic environment, and should be recoverable under the AER's regulatory framework. According to CEG, a producer's margin reflects the currently limited global supply of transmission and distribution equipment compared to large growth in global demand.[610]

The CEG methodology for calculating a real forecast producer's margin is based on averaging the growth rate of forecast margins from JP Morgan and Goldman Sachs for three European producers of electricity equipment – ABB, Prysmian and Nexans.[611] Table C.20 sets out CEG's findings on a producer's margin escalator.

CEG noted that JP Morgan's figures are based on earnings before interest and taxes (EBIT) while Goldman Sachs figures are based on earnings before interest, taxes, depreciation and amortization (EBITDA).[612] CEG also acknowledged that given the limited data sources available to measure producers' margins:

> …it is always possible that ABB, Prysmian and Nexans are 'special cases' of equipment suppliers that, peculiar to the rest of their competitors, can expect to earn high margins in future years. However, while we cannot locate similar long term forecasts for other firms, we note that short term forecasts by Goldman Sachs has similarly robust forecasts of earnings growth across all firms in the sector.[613]

CEG also stated that it has assumed zero growth in producers' margins beyond the forecast horizon to 2011, given the absence of data.[614]

609 CEG, *NSW electricity businesses*, pp. 29–38.
610 CEG, *NSW electricity businesses*, pp. 32–34.
611 CEG, *NSW electricity businesses*, p. 37.
612 CEG, *NSW electricity businesses*, p. 34.
613 CEG, *NSW electricity businesses*, p. 35.
614 CEG, *NSW electricity businesses*, p. 37.

Table C.20: CEG's proposal on real escalators for producer's margin (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
ABB Power Products (JP Morgan)	3.6	2.9	n/a	n/a	n/a	n/a	n/a
ABB Power Systems (JP Morgan)	7.5	5.8	n/a	n/a	n/a	n/a	n/a
Prysmian (JP Morgan)	18.8	9.9	6.3	7.6	n/a	n/a	n/a
ABB (Goldman Sachs)	5.1	3.0	n/a	n/a	n/a	n/a	n/a
Prysmian (Goldman Sachs)	9.9	5.4	6.0	n/a	n/a	n/a	n/a
Nexans (Goldman Sachs)	11.8	5.3	n/a	n/a	n/a	n/a	n/a
CEG's average producer's margin	9.5	5.4	6.1	7.6	0.0	0.0	0.0

Source: CEG, *NSW electricity businesses*, p. 37.

C.5.5.2 Consultant review

PB examined the CEG methodology for estimating a producer's margin as part of its review of TransGrid's revenue proposal. PB noted that the methodology is based on the forecast growth in EBIT and EBITDA margins for a sample of electrical equipment producers. PB stated that the forecast company margins used to determine the escalation of a producer's margin also includes the effect of increased efficiencies associated with the higher utilisation of facilities, plant and administrative overheads that occur during periods of high manufacturing demand. Therefore in PB's view, the use of the EBIT and EBITDA margin is only applicable for companies that remain at full capacity for a sustained period of time. In all other cases the resulting escalation based on EBIT would be higher than the escalation of the margin charged on contracts.[615]

PB acknowledged that sufficient documented anecdotal evidence supports the implicit assumption that electrical equipment producers are currently near full production capacity, have been for some time, and are likely to remain at or near full capacity for some time to come. Therefore, PB accepted the underlying basis for the CEG forecast.[616]

PB noted that the producer's margin escalation for 2009–10 and 2010–11 is based on a forecast for one company only (Prysmian). PB reported that there is a 99% and 84% variance between the two Prysmian forecasts for 2007–08 and 2008–09, respectively. PB noted CEG's view that the cause of this variance is a lag in the timing between the two forecasts:

> These large differences are primarily differences in the timing of increases – with Goldman Sachs predicting slightly earlier margin growth than JP Morgan followed by lower margin growth in 2008 and 2009. However, when

[615] PB, p. 98.
[616] PB, p. 98.

> taken across all of the relevant years the average forecast increase in margins is broadly similar (12.0% vs 13.5%).[617]

PB is of the view that the forecast based solely on Prysmian results significantly overstates the forecast average industry producer's margin growth. On this basis, PB remained of the view that a single company forecast for Prysmian is not a reasonable basis for predicting the forecast industry average producer's margin increases for 2009–10 to 2010–11. PB therefore recommended that no real escalation for producer's margin be applied beyond 2009.[618]

C.5.5.3 AER considerations

As noted in section C.2 of this appendix, the AER considers that the introduction of a new producer's margin escalator is inappropriate as it:

- represents a movement beyond the AER's obligation to provide regulated businesses a reasonable opportunity to recover efficient costs towards providing compensation for changes in input costs at a very fine level of detail. The AER considers it sufficient to monitor whether the cost of finished goods, as opposed to the component parts, need to be escalated above or below CPI
- is not supported by robust data.

Producers' margins will already be embedded in base cost estimates (i.e. as at 31 June 2007). What is in question is the extent to which the existing producers' margins are expected to change in real terms over the next regulatory control period and, if a real change is expected, how to reliably measure it.

CEG has recommended the use of EBIT and EBITDA to measure producers' margins. The producers' margin being measured is defined as the difference between the price of a unit and the cost of producing that unit. Increases in EBIT (or EBITDA) could be the result of:

- an increase in prices, and/or
- an increase in volumes, and/or
- a decrease in costs.

This was noted by ABB (one of the equipment suppliers examined by CEG), in its latest financial report:

> EBIT and EBIT margin rose, mainly reflecting the improved cost efficiency of higher factory loadings, continuing operational improvements and a supportive pricing environment.[619]

On this basis the AER considers that it is unreasonable to use EBIT (or EBITDA) as a direct proxy for margins (or increased prices). The AER does not consider it

---

617 PB, p. 98.
618 PB, p. 99.
619 ABB, 2008 second quarter results, accessible at: <http://www.abb.com/cawp/seitp202/b4ca86e07eeda409c125749000162bcb.aspx>.

appropriate to allow NSPs to recover costs associated with other aspects of an increase in EBIT.

The AER also notes CEG's acknowledgement that there are limited long-term forecasts of producers' margins available, and considers this to be a significant issue in forming an estimate with any degree of reliability. CEG has used six forecasts (see table C.20). Effectively CEG is basing its forecasts on a sample of three firms. In doing so CEG has not demonstrated that these firms are representative of the entire market supplying equipment to Australian electricity network service providers. Furthermore, as noted by PB, the forecasts of margins beyond 2009 are dependent on six data points of three companies from two different forecasters (Goldman Sachs and JP Morgan).

C.5.5.4 AER conclusions

As noted above the AER has general concerns regarding the introduction of a producer's margin escalator. Also, the data used to substantiate these costs are not robust. In the AER's view, the estimates of a producer's margin presented by CEG:

- are highly uncertain
- are based on forecasts of few equipment suppliers
- contain unreasonable assumptions about the relationship between EBIT (and EBITDA) and price increases.

The AER rejects the producer's margin escalators proposed by CEG as it does not meet the underlying objective for inclusion in forecast costs under clause 6A.6.7(c) of the NER. Specifically, the information presented by CEG is not sufficient to satisfy the AER that the associated expenditure reasonably reflects a realistic expectation of cost inputs over the next regulatory control period. The AER considers the addition of a producer's margin escalator would represent a movement beyond the AER's obligation to provide a reasonable opportunity to recover efficient costs and also represent a level of compensation for costs that is inconsistent with the general incentive framework.

The effect of the AER's decision to not apply real cost increases associated with the producer's margin escalator is to allocate the portion of costs assigned to this escalator to the "other" escalation category, which is escalated by CPI only.

C.5.6 Construction costs

C.5.6.1 CEG/TransGrid

TransGrid engaged CEG to forecast construction cost escalators.[620] The construction cost escalator incorporates both materials and labour costs. CEG concluded that an average of the total engineering construction cost escalators calculated by Econtech[621]

[620] CEG, *NSW electricity businesses*, pp. 26–27.

[621] The Econtech forecast was obtained from the Construction Forecasting Council website at: <http://www.cfc.acif.com.au/>. CEG advised that the data it used was updated on 15 November 2007.

and Macromonitor[622], deflated by CPI, provides an appropriate real estimate of construction costs.[623] The Econtech, Macromonitor and CEG construction cost forecasts are set out in table C.21.

Table C.21: CEG's proposal on real construction cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Econtech	0.2	0.6	1.3	1.1	1.2	1.8	2.4
Macromonitor	4.3	3.5	0.5	0.3	1.0	2.1	2.8
CEG	2.3	2.1	0.9	0.7	1.1	1.9	2.6

Source: CEG, *NSW electricity businesses*, p.27.

C.5.6.2 AER considerations

The Econtech engineering construction cost forecasts used by CEG were obtained from the Construction Forecasting Council's website. The AER has obtained updated engineering construction cost forecast from this source and deflated them by CPI in order to provide real forecasts.[624] The AER notes that there is no publicly available updated data on engineering construction costs from Macromonitor. The updated Econtech forecasts for engineering construction costs are shown in table C.22.

Table C.22: Econtech's real engineering construction cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
Updated Econtech engineering	–0.3	–1.9	0.4	1.2	1.1	1.0	1.0	0.9

Source: Construction Forecasting Council, website <http://www.cfc.acif.com.au/>.
Note: The average is calculated for 2009–10 to 2013–14.
The figures provided on Construction Forecasting Council's website take into account data and other information available up to 1 May 2008.

There is some difference between the construction cost forecasts provided by CEG and the updated Econtech construction cost forecast. Given the change in economic conditions since 2007, the AER considers that it is reasonable to adopt the updated Econtech construction cost forecasts as they reflect the most recent information and

622 Macromonitor, *Australian Construction Outlook 2008*, November 2007; Macromonitor, *Forecasts of cost indicators*, p. 19.

623 The total engineering construction cost forecasts used by Macromonitor and Econtech are based on ABS, *Engineering Construction Activity, Australia* (Cat no: 8762.0). This publication contains estimates of engineering construction activity in Australia, which were complied from the Engineering Construction Survey. This survey measures the value of all engineering construction work undertaken in Australia. This value excludes the cost of land, repair and maintenance activity, the value of any transfers of existing assets, the value of installed machinery and equipment not integral to the structure and the expenses for relocation of utility services. However, a contract for the installation of machinery and equipment which is an integral part of a construction project is included. The type of construction projects covered by the survey include bridges, railways, pipelines, power stations, and transmission/distribution electricity lines.

624 Econtech, *ANSIO,* 22 July 2006.

therefore are a reasonable expectation of movements in construction costs into the next regulatory control period.

Further, the AER does not consider it appropriate to rely on the forecasts presented by Macromonitor because there is little information available on the methodology used to forecast engineering construction costs.

Accordingly, the AER is not satisfied that CEG's construction cost escalators reflect a realistic expectation input costs, required to meet the capex and opex objectives over the next regulatory control period. The AER will apply the updated Econtech construction cost forecasts to TransGrid's capex proposal.

C.5.6.3 AER conclusions

The AER's conclusion on forecast construction cost escalators is set out in table C.23.

Table C.23: AER's conclusion on real construction cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
AER	–0.3	–1.9	0.4	1.2	1.1	1.0	1.0	0.9

Appendix D: Contingent projects

This appendix sets out the drivers of approved contingent projects, their scope and specific trigger events. Under clause 6A.8.2 of the NER, TransGrid must demonstrate to the AER's satisfaction that the relevant trigger event in relation to a contingent project has occurred before an assessment of any adjustments to TransGrid's maximum allowed revenue (MAR). Where a trigger event occurs, the scope of a contingent project must not include any projects (or associated project scope) contained in TransGrid's approved capex allowance.

Where TransGrid makes a contingent project application, it is expected to comply with the *Process guideline for contingent project applications under the National Electricity Rules – September 2007* and accordingly, either before or during the pre-lodgement consultation, it is expected to develop feasible options and costs that address the need for the project. Generally, the AER expects TransGrid to provide supporting information with its contingent project application that includes:

- the final regulatory test assessment
- tender submissions
- contracts
- other investment appraisals.

The AER's decision on the drivers, scope and triggers for each of the contingent projects proposed by TransGrid is set out below.

Kemps Creek – Liverpool 330 kV line – Undergrounding of all or part of the proposed connection

The driver for this project is the possibility of ongoing load growth and subsequent increasing power flows across:

- the lines supplying the Sydney South, Liverpool and Ingleburn load centres
- the Beaconsfield West and Haymarket 330 kV substations.

The scope of the project involves undergrounding all or part of a double circuit 330 kV transmission line between Kemps Creek and Liverpool. The indicative cost of this project is $108 million.

The trigger for this project is twofold:

1. A determination by the environmental consent authority that a specific amount of undergrounding is required for the project to be approved.

   And

2. The project with undergrounding satisfies the regulatory test.

Hunter Valley to coast 500 kV development of a double circuit 500 kV line development

The driver for this project is the possibility of power station development in the Hunter Valley area to help address the increased load in the Newcastle – Sydney – Wollongong load corridor.

The scope of the project involves the development of a double circuit 500 kV line between the Hunter Valley and Eraring. The indicative cost of this project is $270 million.

The trigger for this project is either a northern or western NSW power station development exceeding 400 MW, or the development of the Queensland network interconnection that enables an increase in NSW import capability that exceeds 400 MW or a spot load development in the Newcastle area exceeding 200 MW, and (for all of these triggers), TransGrid is directed to undertake a regulatory test for a line development under the Last Resort Planning Power provisions of the NER..

Darlington – Balranald system upgrade 275 kV

The driver for this project is possible NSW regulatory amendment that requires TransGrid to address specific environmental challenges (greenhouse gas abatement).

The scope of this project involves an upgrade of the current 220 kV Darlington Point – Balranald – Buronga system to 275 kV through the use of new transformers at Darlington Point and Buronga, new shunt reactors, new switchgear and minor works. The indicative cost of this project is $51 million.

The trigger for this project is the NSW Government directing TransGrid to upgrade these transmission lines to improve its greenhouse gas emissions.

Yass to Wagga 500 kV double circuit transmission line

The driver for this project is the possibility that TransGrid will not be able to meet the power transfer capability between the Yass area and Victoria and the Wagga area. This applies in two situations:

- high power flows towards the NSW west area and Victoria
- high import from Victoria and Snowy towards NSW.

The scope of this project involves developing a new double circuit 500 kV (operating at 330 kV) between Yass and Wagga largely on the route on the existing Yass – Wagga 132 kV line. The indicative cost of this project is $329 million.

The triggers for this project are:

1. A set of coal-fired or gas-fired generators, with a combined output exceeding 200 MW, is committed for connection to the network in the following southern areas of the NSW system south of the Yass/Canberra area:

   Wagga

   Jindera

Buronga / Broken Hill area

Snowy area.

Or

2. The Victorian export capability to Snowy and NSW is increased by 200 MW above the present capability.

   And (for either of these triggers)

The generation development or increased export capability causes a network limitation to arise on the system between Murray and Upper Tumut/Lower Tumut and between Upper Tumut/Lower Tumut and Yass/Canberra.

Liddell – Tamworth 330 kV

The driver for this project is the possibility that TransGrid will need to improve the power transfer capability between Liddell and Tamworth. This requirement applies in two situations:

- high power flow from the north towards the Hunter Valley
- high export to Queensland, over the Queensland network interconnection, leading to high power transfer from Liddell towards the north.

The scope of this project involves replacing the existing lines with a double circuit 330 kV line. The indicative cost of this project is $163 million.

The triggers for this project are:

1. A set of coal-fired or gas-fired generators, with a combined output exceeding 600 MW (or wind farm developments that provide the equivalent output at time of high NSW load), is committed for connection to the network in NSW in the Tamworth or Armidale area.

   Or

2. The NSW import capability from Queensland is increased by 600 MW above the present capability.

   Or

3. The NSW export capability to Queensland is increased by 200 MW above the present capability.

   And (for all three triggers)

The generation development or increased interconnection capability causes a network limitation to arise on the system between Liddell and Tamworth.

Tamworth – Armidale 330 kV line

The driver for this project is the possibility that TransGrid will be unable to transfer the required energy to and from Queensland and connect potential northern NSW generation.

The scope of this project involves the replacement of the No. 86 line with a new double circuit 330 kV line. The indicative cost of this project is $130 million.

The triggers for this project are:

1. A set of coal-fired or gas-fired generators, with a combined output exceeding 300 MW (or wind farm developments that provide the equivalent output at time of high NSW load), is committed for connection to the network in NSW in the Armidale to north coast area.

   Or

2. The NSW import capability from Queensland is increased by 300 MW above the present capability.

   Or

3. The NSW export capability to Queensland is increased by 200 MW above the present capability.

   And (for all three triggers)

The generation development or increased export capability causes a network limitation to arise on the system between Tamworth and Armidale.

Bannaby – Yass reinforcement

The driver for this project is the possibility that TransGrid will be unable to transfer the required power from the south at Snowy or from Victoria due to line rating constraints.

The scope of this project involves the uprating of the Bannaby to Yass (No. 39) 330 kV line and the Marulan to Yass (No. 4 and No. 5) 330 kV lines to 100 degree Celsius design conductor clearance. The indicative cost of this project is $45 million.

The triggers for this project are:

1. A set of coal-fired or gas-fired generators, with combined output exceeding 200 MW, is committed for connection to the network in the following southern areas of the NSW system south of the Bannaby/Marulan area:

- Yass
- Canberra
- Wagga
- Jindera

- Buronga/Broken Hill area
- Snowy area.

Or

2. The Victorian export capability to Snowy and NSW is increased by 200 MW above the present capability.

And (for either of these triggers)

The generation development or increased export capability causes a network limitation to arise on the system between Yass and Bannaby.

Cooma area

The driver for this project is the possible development of a number of gas-fired and wind generation developments in the Comma/Bega area. If a sufficient number of these developments proceed, TransGrid will require additional transmission capacity.

The scope of this project involves the construction of either a 132 kV or 330 kV line between Williamsdale and the Cooma area. The indicative cost of this project is $40 million.

The trigger for this project is the emergence of one or more generators totalling 225 MW (or more) to be connected to the transmission network that services the Cooma area.

New 500/330 kV substation at Richmond Vale

The drivers for this project are either major load development in the Newcastle area or by generation development in NSW. In particular, the need for this project may arise if:

- a significant industrial load is required in the Newcastle area, such as an aluminium smelter, and there is a need to reinforce the 300 kV system supporting the Newcastle area

- the 330 kV supply to the Newcastle area needs supporting due to the 500 kV line development between the Hunter Valley and the coast.

The scope of this project involves the establishment of a 500/330 kV substation at Richmond Vale. The indicative cost of this project is $80 million.

The trigger for this project is two fold:

1. The environmental consent authority determines that a 500 kV transmission line between the Hunter Valley and Eraring must utilise the route of an existing 330 kV line that supplies the Newcastle area in order to be approved.

And

2. The project including the 500/ 330 kV substation satisfies the regulatory test.

Appendix E: Self insurance

This appendix sets out the AER's assessment of TransGrid's proposed self insurance allowance in its opex forecast for the next regulatory control period.

AER considerations

Self insurance is not specifically addressed in the NER, consequently TransGrid's self insurance claims have been assessed by the AER against the opex objectives and criteria in clause 6A.6.6 of the NER. Specifically, the AER has assessed TransGrid's self insurance claims to determine whether the proposed allowance reasonably reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives.

The self insurance premiums proposed by TransGrid's consultant (SAHA) have been derived by estimating the annual probability of each proposed self insurance event occurring and the costs associated with each of those events occurring.[625]

The AER has assessed the efficiency and prudence of the proposed self insurance claims by considering whether the probability of an event occurring and the costs associated with the event (and therefore the associated insurance premium) have been reasonably determined.

Having reviewed the analysis by SAHA, and the assessment by PB[626], the AER is satisfied that TransGrid's proposed allowances for self insurance for the following risks reasonably reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives:

- fraud risk
- insurers' credit risk
- counterparty credit risk
- risk of non-terrorist impact of planes and helicopters.

However, the AER does not consider that all of TransGrid's proposed self insurance premiums reflect the efficient costs that a prudent operator in the circumstances of TransGrid would incur to achieve the opex objectives, and is concerned that in several areas they do not present a realistic expectation of the costs of self insurance required in the next regulatory control period. These areas of concern are discussed further below.

---

625 SAHA, *TransGrid Self Insurance Risk Quantification*, Final Report, confidential, 20 May 2008; SAHA, *TransGrid Self Insurance Risk–supplementary report-response to AER/PB*, confidential, 5 August 2008

626 PB, pp. 214–219.

Environmental contamination[627]

Self insurance is sought in relation to aspects of TransGrid's business that could potentially expose it to the risk of unintentionally polluting its surrounding environment which could lead to a range of legal and financial consequences for it. This may include settlement of claims by an individual or group of individuals who have suffered health effects or financial losses, legal costs associated with negotiating that settlement, and the cost of remediation of any contaminated site.

The proposed self insurance premium for environmental contamination is $500 000 per annum.

SAHA has assumed that TransGrid's external insurance only covers personal property belonging to the insured party. Therefore, SAHA indicated that "it appears that TransGrid might be fully exposed to any third party liability claims stemming from gradual pollution events".

The AER considers that without a thorough understanding of TransGrid's potential exposure it is not possible to determine a reliable self insurance premium.

SAHA noted that it is very difficult to generate a robust data set upon which a forward looking estimation of exposure can be made. SAHA therefore based the future probability and costs associated with such an event on historical information provided by TransGrid.

However, the AER notes that there is insufficient information regarding historical incidents to determine a robust estimate of the frequency of occurrence or historical costs.

The AER notes that PB recognised that there were a number of uncertainties regarding the potential for environmental damage both in terms of the number of potential sites and the cost of remediation. PB suggested that TransGrid consider undertaking a survey of its sites in order to provide a better understanding of the risk faced from environmental damage. PB noted that the results of such a survey would improve the accuracy of the estimated cost of environmental damage.

While PB considered the proposed self insurance allowance for this risk to be a reasonable estimate, the AER has rejected the claim for self insurance on the basis that the estimates of the probability of occurrence and the costs of future events is not sufficiently robust to be used to calculate the self insurance premium. Based on the information provided, the AER is not satisfied that the proposed allowance reasonably reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c). Accordingly, the AER does not accept the proposed self insurance premium for this risk of $500 000 per annum.

[627] SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 42–47; SAHA, *Supplementary report*, pp. 7–8.

Bomb threat/hoax, terrorism[628]

TransGrid faces the risk that a malicious and deliberate act of sabotage by way of a bomb threat and or extortion attempt is undertaken by a third party. This would impact on TransGrid's ability to provide transmission services, and/or the costs associated with providing such services.

The proposed self insurance premium for this risk is $23 500 per annum which is made up of the self insurance component for the impact of a bomb threat, hoax or extortion ($5200) and a component for acts of terrorism ($18 300).

The AER is satisfied with the assumptions used by SAHA to calculate the self insurance premium for the impact of a non-terror related bomb threat, hoax or extortion on TransGrid.

In respect of an extortion or bomb threat that pertains to a terrorist related event, TransGrid is eligible under the Terrorism Act 2003 to claim any loss or damage done to its property and consequential third party liability as a result of a stated "terrorist act". However, the Terrorism Act 2003 only covers eligible insured assets, with any financial costs resulting from terrorist acts on self insured assets being borne by the TNSP.

In calculating the self insurance premium for the risk of a terrorism event, SAHA noted that it is difficult to determine the probability of how often TransGrid's assets may be subject to acts of terrorism and what the cost of a successful terrorism event would be. Nonetheless, SAHA made certain assumptions about the probability to calculate the risk premium for self insurance purposes.

Under the NER a terrorism event is a defined pass through event.

Given the difficulty associated with calculating a risk premium for a terrorism event and that a terrorism event is listed as a defined pass through event under the NER, the AER considers that the claim for self insurance should be rejected.

The AER does not consider that the proposed self insurance premium for a terrorism event reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c). Accordingly, the AER will reduce the self insurance premium for this risk from $23 500 per annum to $5200 per annum ($23 500 − $18 300).

Earthquake[629]

The SAHA analysis focused on the probability and consequence associated with an earthquake of magnitude 5 and 6 impacting TransGrid's network.

The proposed self insurance premium for the impact of an earthquake on TransGrid's assets is $165 000 per annum. This premium is made up of an amount for the impact of an earthquake of magnitude 5 ($146 000) and an amount for the impact of an earthquake of magnitude 6 ($19 000). The self insurance premium reflects the costs

628 SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 48–54.
629 SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 55–64; SAHA, *Supplementary report*, pp. 11–13.

associated with repairing TransGrid's assets and an amount for public liability in the event of an earthquake.

SAHA examined the number of earthquakes impacting NSW over the last 166 years to determine the future probability of an event for TransGrid.[630]

In the case of earthquakes of a magnitude 5, SAHA observed that 22 such earthquakes have occurred in NSW over the past 166 years. The data also allowed SAHA to examine how many of these earthquakes occurred in TransGrid's network area and provide an estimate of potential costs. SAHA calculated the potential cost associated with a magnitude 5 earthquake based on the average length of line affected by an earthquake.

The AER is satisfied that the assumptions used by SAHA to calculate the self insurance premium for the cost impact of a magnitude 5 earthquake on TransGrid's network are reasonable. The AER therefore accepts the self insurance premium of $146 000 for the impact of earthquakes of a magnitude 5.

In the case of magnitude 6 earthquakes, SAHA indicated that no such earthquakes were recorded in NSW over the 166 year period. However, SAHA assumed that there was a potential for at least one magnitude 6 earthquake to occur in NSW over this period and therefore adopted a probability of 1 in 166 years.

PB noted that while a magnitude 6 earthquake has never been experienced in NSW, a number of magnitude 6 earthquakes have been experienced in the adjoining states of South Australia and Queensland. PB stated that the estimate of frequency of 1 in 166 years used to calculate the costs indicates that a magnitude 6 earthquake is considered to be a very remote event.

The AER notes that earthquake forecasting can be regarded, at best, as imprecise. Where there are no historical observations, as is the case for magnitude 6 earthquakes in NSW, earthquake prediction could be considered virtually impossible. The AER considers that SAHA has provided no reasonable rational basis for the adoption of a 1 in 166 year probability of a magnitude 6 earthquake in NSW.

While PB considered the assumptions and costs used to calculate the risk premium for earthquakes to be reasonable, based on the information provided the AER rejects the self insurance claim for a magnitude 6 earthquake. This is on the basis that the estimate of the probability of occurrence is not sufficiently robust to be used to determine the self insurance allowance and therefore the proposed allowance does not reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

Accordingly, the AER has reduced TransGrid's proposed self insurance allowance for earthquakes from $165 000 per annum to $146 000 per annum ($165 000 − $19 000).

[630] Sourced from Geoscience Australia − compiled by SAHA.

Bushfires[631]

SAHA noted that NSW has proven to be one of the bushfire prone states in Australia. It stated that bushfire events can cause significant damage to electricity transmission assets and considered that TransGrid should be provided with a self insurance premium.[632]

The proposed self insurance premium for bushfires is $267 000 per annum. SAHA's assessment of this risk was separated into two types of bushfires—those ignited by TransGrid's assets, and those ignited by a third party. Each of these scenarios is examined below.

Bushfires ignited by TransGrid's assets[633]

The self insurance premium for bushfires ignited by TransGrid's own assets consists of a premium associated with "very minor" bushfires ($3000), a premium for minor bushfires ($50 000) and a premium for major bushfires ($8000).

In terms of "very minor" bushfires—that is, bushfires causing damage below $1 million—SAHA assumed that the average value of TransGrid's past very minor bushfire costs provided a reasonable proxy for future incidents and costs. The AER considers this approach to be appropriate based on the timeframe of historical observations and the significant number of events over that period. Therefore, the AER accepts the self insurance premium of $3000 per annum.

In the case of "minor" bushfires—that is, bushfires causing damage above $1 million—TransGrid indicated that its assets have not started a bushfire that has lead to damage of greater than its $1 million insurance deductible. However, SAHA considered it reasonable to assume that TransGrid could potentially ignite one minor bushfire once every 20 years, which equates to a probability of 0.05.

The AER considers that SAHA has not provided robust basis for the adoption of a 1 in 20 year probability of a minor bushfire. As a consequence, the AER rejects the claim for the self insurance premium of $50 000 per annum relating to minor bushfires on the basis that the probability of such an event has not been reasonably determined. The AER does not consider that the proposed allowance reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

The SAHA approach to determining the probability of "major" bushfires—that is, bushfires causing more than $10 million damage—ignited by TransGrid's assets is summarised below:

- SAHA determined the number of bushfires in NSW caused by electricity assets (8 per annum over the past 13 years).[634] SAHA indicated that this translated to

631 SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 72–81; SAHA, *Supplementary report*, pp. 14–16.
632 SAHA, *TransGrid Self Insurance Risk Quantification*, p. 72.
633 SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 75–79.
634 Based on information provided to SAHA by the NSW electricity businesses (incorporates very minor and minor bushfires ignited by electricity assets).

approximately 104 (i.e. 8 × 13) bushfires caused by electricity assets over the past 13 years since the inception of the TransGrid.

- SAHA noted that over this (13 year) period, only one major bushfire had occurred – the Appin fire started by Integral Energy. SAHA therefore calculated the probability of a minor bushfire ignited by electricity assets becoming a major bushfire as 1 in 104 (or 1 in 13 years).

- SAHA then applied the average annual number of very minor bushfires caused by TransGrid's assets to the expected probability of a bushfire (of any size) becoming a major bushfire (i.e. 1 in 104) to determine the individual probability of a major bushfire for TransGrid.

- SAHA then reduced this probability to reflect the fact that TransGrid's operating region covers both NSW and the ACT.

The AER considers that the basis for determining the probability of these events is not capable of being supported. In particular:

- there is no rationale for the application of a 13 year historical period. The AER notes that there is nothing inherently important about TransGrid's inception date

- the fact that one bushfire has occurred since the inception of TransGrid does not provide a basis for assuming that another major bushfire will occur in 13 years. There are other factors that impact on the probability of such an event rather than 1 historical observation over an arbitrary timeframe

- the SAHA data concerning the number of bushfires in NSW caused by electricity assets includes those caused by both transmission and distribution assets. Given the differences in coverage between the transmission and distribution networks, it is not clear that the combined total can be used as the basis for determining the probability of a bushfire caused by TransGrid's assets

- it is not clear that TransGrid's experience with very minor bushfires can be used to predict the possibility of a major bushfire.

In calculating the costs associated with a major bushfire ignited by TransGrid's assets, SAHA relied on information from the Centre for International Economics (CIE).[635] In particular, SAHA relied upon a functional relationship between damage costs and area burnt by bushfires proposed by CIE.[636] The CIE report was not undertaken in connection with TransGrid's revenue proposal.

The AER considers that the functional relationship between damage costs and area burnt proposed by CIE cannot be relied upon. In particular, based on an examination of the historical data underpinning the CIE modelling, the AER is unable to comprehensively match the values provided in the CIE report with those in the base data.[637] In addition, for those values that can be identified, it appears that the damage

---

635 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, November 2000.

636 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, pp. 112−113.

637 <http://www.ema.gov.au/ema/emadisasters.nsf/webEventsByCategory?OpenView&Start=1&Count=30&Expand=1#1>. While this assessment is based on an examination of the data source in its

costs used by CIE to forecast the relationship have not been converted to constant dollars. As such, the observations are not comparable over time.

Notwithstanding the data issues set out above, the explanatory power of the proposed CIE functional relationship is, in any event, poor. The coefficient of determination is reported as 0.39, implying that only 39 per cent of the variance in bushfire damage cost can be explained by the amount of hectares burnt.[638] This leaves over 60 per cent of the variation in bushfire damage costs unexplained.

While PB considered the assumptions and costs used to calculate the risk premium for bushfires ignited by TransGrid's assets to be reasonable, based on the information provided the AER rejects the associated self insurance premium of $8000 per annum on the basis that the probability of occurrence and associated costs have not been reasonably determined. The proposed allowance does not reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

In total, the AER has reduced the self insurance premium for bushfires ignited by TransGrid's assets to $3000 per annum.

Bushfire ignited by third party[639]

The self insurance premium for bushfires ignited by a third party consists of a premium for minor bushfires ($200 000) and a premium for major bushfires ($6000).

SAHA noted that there is no history of a (minor or major) bushfire ignited by a third party impacting TransGrid's network. However, SAHA suggested that the sheer magnitude of bushfires ignited by third parties in NSW—around 300 per year—indicated that there was a considerable chance that one such minor bushfire could cause damage to TransGrid's assets.[640] As a result, SAHA suggested that it was reasonable to assume TransGrid will be affected by a minor bushfire incident caused by a third party once every 15 years.

The AER notes that the NSW bushfire data referred to by SAHA reflects bushfire incidents in only one year (2002–03) and represented one of the worst bushfire seasons in NSW history.[641] Notwithstanding this issue, the AER considers that SAHA has not established a robust relationship between the incidence of bushfires in NSW and the adoption of a 1 in 15 year probability.

In the case of a major bushfire ignited by a third party, SAHA used the CIE report to derive the probability of a major bushfire in NSW. SAHA combined this information with the previously derived probability of a third party causing a bushfire incident in NSW to derive the probability of a major third party fire in NSW.

---

current format, given the historical nature of the data, the AER would not expect any deviation between this data set and that used by CIE over the observed timeframe.

638 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, p. 113.

639 SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 79–81.

640 SAHA obtained this information from a 2002–03 NSW Rural Fire Services report. However, the report has not been provided to the AER.

641 NSW Rural Fire Service, *Annual Report 2003*.

The AER notes that the proportion of major bushfires accounted for in NSW (from the CIE report) appears to relate to minor rather than major bushfires as proposed by SAHA.[642] Further, as mentioned above, SAHA provided no explanation for assuming a 1 in 15 year possibility of a minor bushfire incident caused by a third party impacting TransGrid (and used as the basis for determining a major bushfire).

As a result, based on the information provided, the AER considers that the probabilities for both minor and major bushfires ignited by a third party do not provide a reasonable basis to calculate the self insurance premium.

In addition, the AER notes that SAHA's forecast costs associated with minor and major bushfires ignited by third parties were derived on the same basis as those for a major bushfire ignited by TransGrid's assets—that is, based on the CIE proposed relationship between damage costs and damage area. As noted, the AER has identified a number of issues associated with the functional relationship used by the CIE.

While PB considered the assumptions and costs used to calculate the risk premium for bushfires to be reasonable, based on the above assessment, the AER rejects the self insurance premium of $206 000 per annum ($200 000 + $6000) in relation to both minor and major bushfires ignited by a third party on the basis that the probability of occurrence and associated costs have not been reasonably determined. The proposed allowance does not reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

In total, the AER has reduced TransGrid's proposed self insurance allowance for bushfires from $267 000 per annum to $3000 per annum ($267 000 – $50 000 − $8000 − $200 000 − $6000).

Risk of non-terrorist impact of planes and helicopters[643]

The proposed self insurance premium for the risk of a non-terrorist impact of aircraft on TransGrid's assets is $128 000 per annum. This self insurance premium is made up of two components of cost associated with wire strikes from aircraft—third party liability and damage to assets.

The calculation of the risk premium associated with third party liability is based on the deductible amount of $250 000 and a frequency estimate of 1 every 3 years. SAHA has analysed the Air Transport Safety Bureau data and ascertained that there are 5.1 aviation wire strikes per year in NSW. TransGrid appears to have experienced three aviation strikes since 2000.[644] PB considered that it is likely that TransGrid suffers fewer aviation strikes per year than a distribution business due to both the length of line and also the design of TransGrid's assets which are generally physically larger and more prominent than distribution assets.

---

642 CIE, *Assessing the contribution of CSIRO - CSIRO pricing review*, p. 108 and Table 7.5.

643 SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 82–87;
SAHA, *Supplementary report*, pp. 16–17.

644 The three air strikes are the strike recorded in the SAHA report, a further strike advised by TransGrid (glider striking the Yass – Marulan 33 kV line) on 16 July 2008 and the a recent strike (RAAF plane striking Armidale – Coffs Harbour 330 kV line) on 13 August 2008.

Given that TransGrid has experienced three aviation strikes over the past eight years and that there are a number of aviation strikes on lines in NSW, PB considered that a frequency of 1 in 3 years was reasonable.

PB considered the assumptions used by SAHA to calculate the self insurance premium for the cost of an aviation strike resulting in damage to TransGrid's assets to be reasonable. The AER is satisfied with the assumptions used by SAHA to calculate the self insurance premium for the cost of an aviation strike resulting in damage to TransGrid's assets and therefore, accepts the self insurance premium.

SAHA assumed that every aviation strike results in third party liability equal to the deductible of $250 000. PB noted that neither TransGrid's submission or the SAHA report provides any information to make an estimate of the proportion of aviation strikes that will result in a third party claim. PB noted that there is no historical evidence of third party claims resulting from aviation strikes. It stated that there is no specific information that assists in estimating the proportion of aviation strikes that will result in a third party claim. However, PB considered it unlikely that more than 50 per cent of aviation strikes would result in a third party claim. PB recommended that the probability that an aviation strike results in a third party claim be reduced by 50 per cent.

The AER notes that TransGrid appears to have experienced three aviation strikes since 2000. Given that TransGrid has experienced such events, the AER notes that a future aviation strike could involve a third party claim. PB has recommended that the probability of a third party claim be reduced by 50 per cent. However, in the absence of any information to support the recommended reduction to reflect a proportion of aviation strikes that will result in a third party claim, the AER does not consider it appropriate to reduce the probability by 50 per cent. The AER accepts the self insurance premium for this risk of $128 000 per annum.

Poles and towers[645]

This category of self insurance covers the cost of damage to towers, lines and cables from an exogenous event (other than earthquake, bushfire, terrorism and impact of aircraft). Damage in this category is generally caused by events such as storms, falling trees and ground subsidence affecting cables.

The proposed self insurance premium for damage to TransGrid's towers, lines and cables is $1.3 million per annum. This self insurance premium includes amounts for towers and wires ($208 000), conductors ($172 000), underground cable ($918 000) and an amount for third party damage ($12 000).

The costs of repairs have been calculated using an average between the weighted average repair and replacement cost, and the actual recorded cost. The frequency of incidents and the number of poles or towers affected has been calculated based on historical data.

The AER considers that, unless historical data is verified to be inaccurate or insufficient, then the historical frequency of events should be multiplied by historical

[645] SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 88–93; SAHA, *Supplementary report*, pp. 18–21.

costs to determine a risk premium. TransGrid provided further information which suggests that the historical recorded repair cost is not likely to be representative of future repair costs.[646] PB accepted the explanation provided by TransGrid and considered that the average used was a reasonable estimate of the repair cost. The AER is satisfied with the explanation provided by TransGrid and accepts the self insurance premium for towers and lines of $208 000 per annum.

For the self insurance premium relating to incidents resulting in damage to TransGrid's tower and pole conductors, the AER is satisfied with the assumptions used by SAHA to calculate the frequency and cost of these events and accepts the self insurance premium of $172 000 per annum.

In relation to the self insurance claim for underground cable incidents, SAHA has relied on two historical incidents recorded by TransGrid over the period 2004 to 2007. SAHA noted the wide divergence between the costs for these incidents—one being $4309 and the other being $3.7 million. SAHA therefore assumed the cost of a future underground cable incident to be the average of these two observations—that is, $1.84 million. Based on this information (2 incidents in 4 years), SAHA assumed the probability of future occurrence to be 0.5.

The AER considers that there are too few observations and too much variance in the costs associated with these observations for a reasonable future cost estimate to be determined. Further, it is not clear that the costs associated with the larger of the two events have been incurred by TransGrid.[647] While noting that PB considered the self insurance premium to be reasonable, based on the information provided, the AER has rejected the claim for self insurance in relation to underground cable incidents on the basis that the estimate of the costs for underground cable incidents is not sufficiently robust to be used to determine the self insurance allowance. This will reduce the self insurance premium by $918 000 per annum.

TransGrid has also sought self insurance in relation to third party damage as a result of damage to TransGrid's towers and wires.

TransGrid indicated that it had not experienced any third party claims in relation to damage to its towers and wires. Notwithstanding this, SAHA considered it reasonable to assume that once every 20 years, a large scale incident involving TransGrid's towers and lines could lead to consequential third party damage in excess of TransGrid's current $250 000 deductible.

The AER notes that SAHA has provided no information in support of this conclusion. While PB considered the self insurance premium associated with third party damage to be reasonable, based on the information provided, the AER has rejected the claim for self insurance on the basis that the probability and cost estimates have not been reasonably determined. This will reduce the self insurance premium for towers and wires by $12 000 per annum. The AER does not consider that the proposed self insurance premium for this component of towers and wires reflects the efficient costs

646 TransGrid, response to PB draft report, confidential, 10 September 2008.

647 SAHA indicated that it had assumed that TransGrid self insures for underground cables and the cost of this incident is unrecoverable from (a) third party.

that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

In total the AER has reduced the self insurance premium for towers and wires from $1.3 million per annum to $380 000 per annum ($208 000 + $172 000). The AER consider that this revised estimate reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

Key assets[648]

This claim relates to the failure of transformers and circuit breakers and the associated costs for TransGrid and consequential third party claims. The proposed self insurance premium for key assets is $672 000 per annum. This consists of self insurance premiums for transformers ($650 000), circuit breakers ($10 000) and third party claims caused by these assets failing ($12 000).

The self insurance premiums for power transformers and circuit breakers have been calculated based on historical costs and frequencies. PB considered the use of historical frequencies to be appropriate as TransGrid has a comprehensive asset monitoring, maintenance and replacement regime that should result in little change to the failure rate over the next regulatory control period.

Given that the self insurance premiums calculated for power transformers and circuit breakers are based on historical costs and frequencies, the AER considers these premiums to be a reasonable estimate of the cost of self insurance.

TransGrid indicated that it had not experienced any third party claims in relation to failure of these key assets. However, SAHA considered it reasonable to assume that such an incidence could occur, and believed that a 1 in 20 year probability of consequential third party damage occurring was reasonable.

The AER notes that SAHA has provided no information in support of this conclusion. As such, based on the information provided, the AER has rejected the claim for self insurance for third party claims on the basis that the estimate of the probability of occurrence is not sufficiently robust to be used to determine the self insurance allowance. The AER does not consider that the proposed self insurance premium for this component of key assets reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c). Accordingly, the AER will reduce the self insurance premium for key assets by $12 000 per annum.

As a result, the AER has reduced the self insurance premium for key assets from $672 000 per annum to $660 000 per annum ($672 000 − $12 000).

Key staff[649]

Key person risk represents the risk that TransGrid could bear an adverse financial impact due to the sudden departure, or death of a key employee.

---

[648] SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 94–101; SAHA, *Supplementary report*, pp. 22–23.

[649] SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 102–105.

The proposed self insurance premium for key person risk is $31 000 per annum.

Generally, key person insurance is available to a business to cover against business interruptions and costs arising from the sudden departure or death of a key employee. However, TransGrid has not retained any external insurance arrangements, choosing instead to self insure for exposure to key person risk.

TransGrid indicated that approximately 27 per cent of total employees were considered key employees. SAHA calculated the proposed self insurance premium as the probability of these employees departing multiplied by the costs associated with that departure.

The AER is not satisfied that a prudent operator would seek insurance for the sudden departure or death of almost 30 per cent of its staff and that the coverage of a simultaneous event of the magnitude of this type would be possible. Further, the analysis provided by SAHA is not supported by information concerning the history of sudden departure or death of employees from either TransGrid or similar businesses.

Notwithstanding the above, it is noted that the self insurance premium is calculated on the basis of the sudden departure or death of all key employees identified by TransGrid. The AER notes, however, that in any year it would be expected that only a fraction of these key employees would suddenly depart or die. The AER considers, therefore, that the self insurance premium is overstated.

Based on the above, the AER considers the proposed self insurance premium for the sudden departure or death of key employees does not reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c). Accordingly, the AER does not accept the proposed self insurance premium of $31 000 per annum for this risk.

Contractual risk[650]

This self insurance claim refers to a situation where the terms or conditions of a contract made between a third party and TransGrid exposes TransGrid to some residual risk—that is, TransGrid does not have mitigation mechanisms within the contract itself for a risk that would be reasonably expected to occur in relation to the provision of the service in question. The proposed self insurance premium for this risk is $11 500 per annum.

SAHA has identified two scenarios of contractual risk for TransGrid:

- the risk that a major design and construction contractor defaults, incurring transition costs
- the risk that Mincom defaults as TransGrid's IT provider, and as such, TransGrid incur unforseen transition costs when transferring to a new provider

The AER considers that the onus is on TransGrid to ensure that the contractual arrangements between itself and a third party are sufficient to mitigate against contractual risk. To the extent this is not the case, the AER would expect that

650 SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 106–109.

TransGrid, rather than its customers, would bear the associated costs. As a result, the AER rejects the proposed self insurance allowance because it does not reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c). The AER does not accept the proposed self insurance premium of $11 500 per annum for this risk.

General public liability[651]

General public liability risk covers incidents where TransGrid is liable for injuries or other losses suffered by member(s) of the general public as a result of its (or its employees') negligence or fault. The self insurance premium for this risk is $12 500 per annum.

SAHA indicated that TransGrid has not incurred any third party general liability claims since its inception. While SAHA noted the lack of industry wide information, the lack of TransGrid specific data, and the infrequent nature of such events, SAHA considered it reasonable to assume that a large scale general public liability event, with a consequence in excess of TransGrid's current $250 000 deductible, could occur 1 in every 20 years.

The AER considers that SAHA has not provided sufficient rationale for the proposed probability and cost estimates associated with general public liability risk and therefore rejects the self insurance claim. Based on the information provided, the AER considers that the proposed allowance does not reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c). Accordingly, it does not accept the proposed self insurance premium of $12 500 per annum for this risk.

Failure to supply[652]

This represents the risk that TransGrid will be unable to supply electricity to the NEM, or that it will be unable to make its network available to generators. The self insurance premium proposed for this risk is $19 000 per annum.

SAHA noted that TransGrid experienced 5 minor events that have resulted in a failure to supply, of which only 3 were the responsibility of TransGrid. Further, SAHA indicated that the cost in claims for each of these has been less than $5000. The AER notes, however, that no information concerning the period over which these events occurred has been provided.

SAHA indicated that TransGrid had not recorded any failure to supply incident that resulted in a cost above the deductible. However, SAHA considered it reasonable to assume at least 1 occurrence of an above deductible failure to supply incident every 15 years.

The AER notes that SAHA has provided no information in support of this conclusion. As such, based on the information provided, the AER has rejected the claim for self insurance on the basis that the probability of occurrence has not been reasonably determined and the proposed allowance therefore does not reflect the efficient costs

[651] SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 110–112.
[652] SAHA, *TransGrid Self Insurance Risk Quantification*, pp. 113–115.

that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c). The AER does not accept the proposed self insurance premium of $19 000 per annum for this risk.

AER conclusion

For the reasons set out above, the AER is not satisfied that SAHA has provided robust analysis which supports the probability of certain events occurring or that the costs of those events are reasonable. Accordingly it has not accepted the calculation of the self insurance premiums.

The AER considers TransGrid's proposed self insurance allowance does not reflect the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

As a result of its analysis of the information provided the AER is satisfied that the revised estimate of the self insurance allowance for the next regulatory control period set out in table E.1, based on the above accepted self insurance premiums, reflects the efficient costs that a prudent operator in the circumstances of TransGrid would require to achieve the opex objectives, as required by clause 6A.6.6(c).

Table E.1: AER's conclusion on TransGrid's self insurance allowance for the next regulatory control period ($m, 2007−08)

	TransGrid's proposal	AER's adjustments	AER's conclusions
Total self insurance risk premium	15.84	–9.09	6.76

Appendix F: Efficiency carry forward mechanism calculation

Table F.1: Calculation of carry forward amounts for the next regulatory control period under the efficiency carry forward mechanism

Year	2003–04	2004–05	2005–06	2006–07	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2003–14	Total
Actual CPI inflation rate(a)	1.98%	2.36%	2.98%	2.44%	4.24%	2.80%						
Target ($m, 2003–04)		116.94	116.50	116.13	115.84	115.65						581.07
Actual ($m, nominal)		117.23	120.73	120.69	119.70	127.59						605.93
Target ($m, 2008–09)		135.32	134.81	134.38	134.04	133.83						672.37
Actual ($m, 2008–09)		134.07	134.48	130.90	125.63	129.36						654.46
Efficiency gain/loss ($m, 2008–09)		1.24	–0.92	3.15	4.92	–3.94						
Carryover ($m, 2008–09)												
2004–05			1.24	1.24	1.24	1.24	1.24					
2005–06				–0.92	–0.92	–0.92	–0.92	–0.92				
2006–07					3.15	3.15	3.15	3.15	3.15			
2007–08						4.92	4.92	4.92	4.92	4.92		
2008–09							–3.94	–3.94	–3.94	–3.94	–3.94	
Forecast carryover amounts ($m, 2008–09)							4.46	3.22	4.14	0.98	–3.94	8.86

(a) Actual CPI inflation rates based on March−March quarters. This is consistent with the actual inflation figures used in the roll forward model (RFM). The 2008–09 inflation figure is a forecast and will updated with the actual figure at the time of the final decision.

Appendix G: Performance incentive curves

The following tables and figures represent the scale of the financial penalty or reward (y-axis) resulting from TransGrid's performance (x-axis) against each of its parameters. Tables G.1 to G.6 show the set of linear equations represented in figures G.1 to G.6.

In accordance with the service target performance incentive scheme the s-factor result for each calendar year should be determined by the following formula:

$$S_{ct} = S_1 + S_2 + S_3 + S_4 + S_5 + S_6$$

where:

S_{ct} = the total service standards factor (s-factor)

ct = the time period/calendar year

S_1 = s-factor for transmission line availability

S_2 = s-factor for transformer availability

S_3 = s-factor for reactive plant availability

S_4 = loss of supply event frequency > 0.05 system minutes

S_5 = loss of supply event frequency > 0.25 system minutes

S_6 = average outage duration

Figure G.1: Transmission line availability

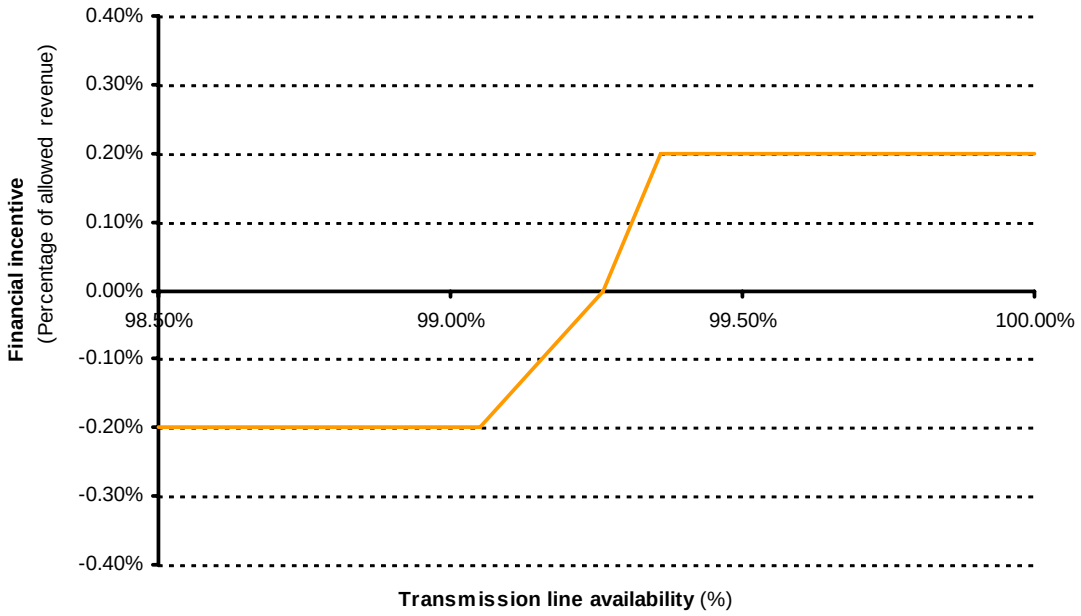


Table G.1: Transmission line availability

							Where:					
S1	=	–0.002000						Availability	<	99.05%		
S1	=	0.952381	x	Availability	+	–0.945333	99.05%	≤	Availability	≤	99.26%	
S1	=	2.000000	x	Availability	+	–1.985200	99.26%	≤	Availability	≤	99.36%	
S1	=	0.002000					99.36%	<	Availability			

Figure G.2: Transformer availability

Table G.2: Transformer availability

							Where:					
S2	=	–0.001500							Availability	<		97.26%
S2	=	0.116279	x	Availability	+	–0.114593	97.26%	≤	Availability	≤		98.55%
S2	=	0.517241	x	Availability	+	–0.509741	98.55%	≤	Availability	≤		98.84%
S2	=	0.001500					98.84%	<	Availability			

Figure G.3: Reactive plant availability

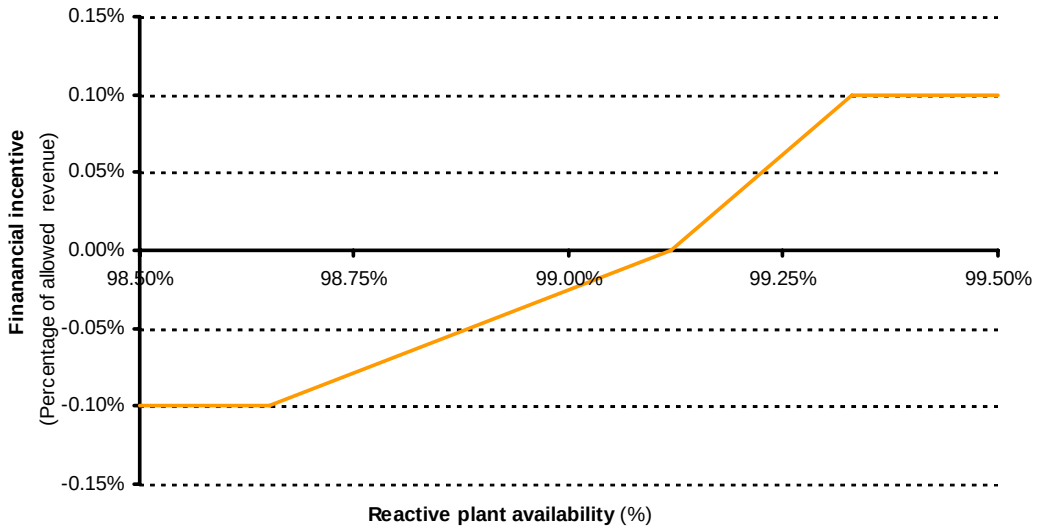


Table G.3: Reactive plant availability

								Where:				
S3	=	–0.001000							Availability	<	98.65%	
S3	=	0.212766	x	Availability	+	-0.210894		98.65%	≤	Availability	≤	99.12%
S3	=	0.476190	x	Availability	+	-0.472000		99.12%	≤	Availability	≤	99.33%
S3	=	0.001000						99.33%	<	Availability		

Figure G.4: Loss of supply event frequency > 0.05 system minutes

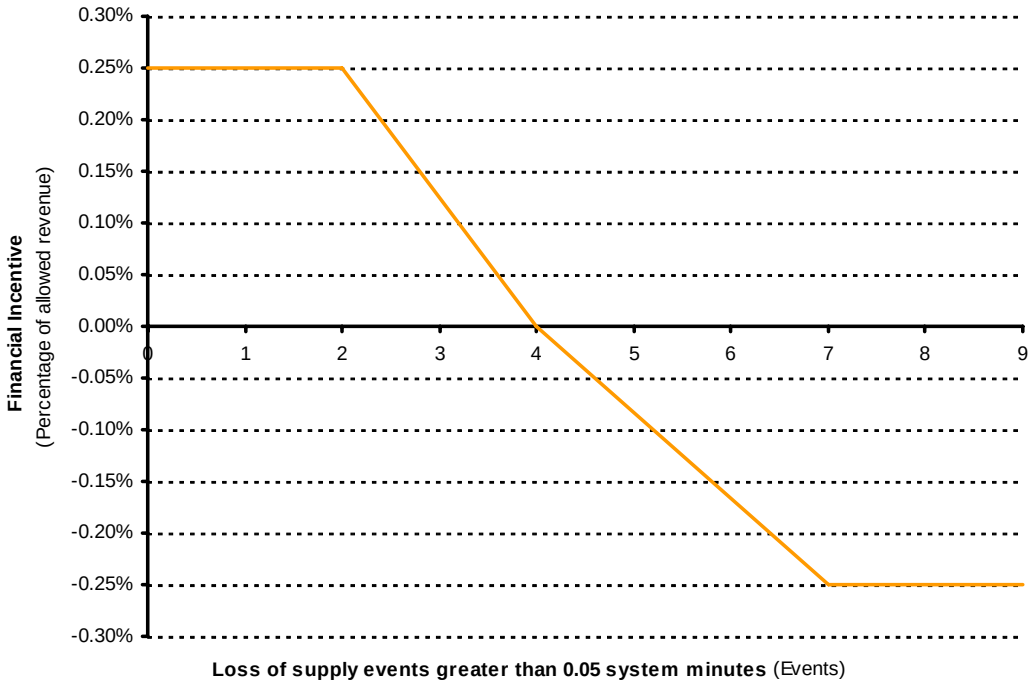


Table G.4: Loss of supply event frequency > 0.05 system minutes

							Where:					
S4	=	–0.002500					7	<	No. of events			
S4	=	–0.000833	x	No. of events	+	0.003333	4	≤	No. of events	≤	7	
S4	=	–0.001250	x	No. of events	+	0.005000	2	≤	No. of events	≤	4	
S4	=	0.002500							No. of events	<	2	

Figure G.5: Loss of supply event frequency > 0.25 system minutes

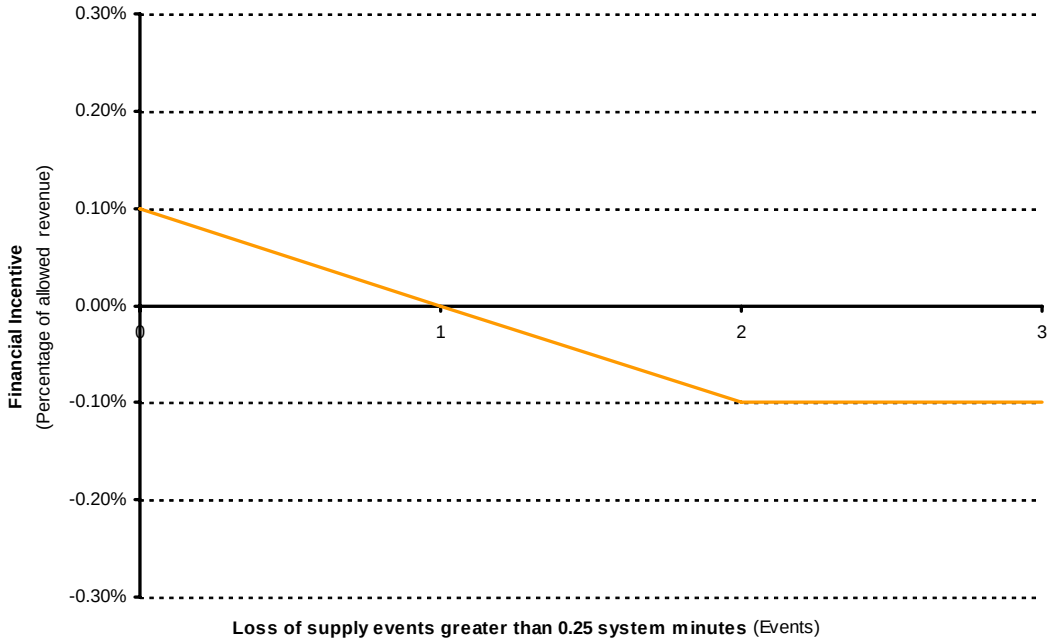


Table G.5: Loss of supply event frequency > 0.25 system minutes

							Where:				
S5	=	–0.001000					2	<	No. of events		
S5	=	–0.001000	x	No. of events	+	0.001000	1	≤	No. of events	≤	2
S5	=	–0.001000	x	No. of events	+	0.001000	0	≤	No. of events	≤	1
S5	=	0.001000							No. of events	<	0

Figure G.6: Average outage duration

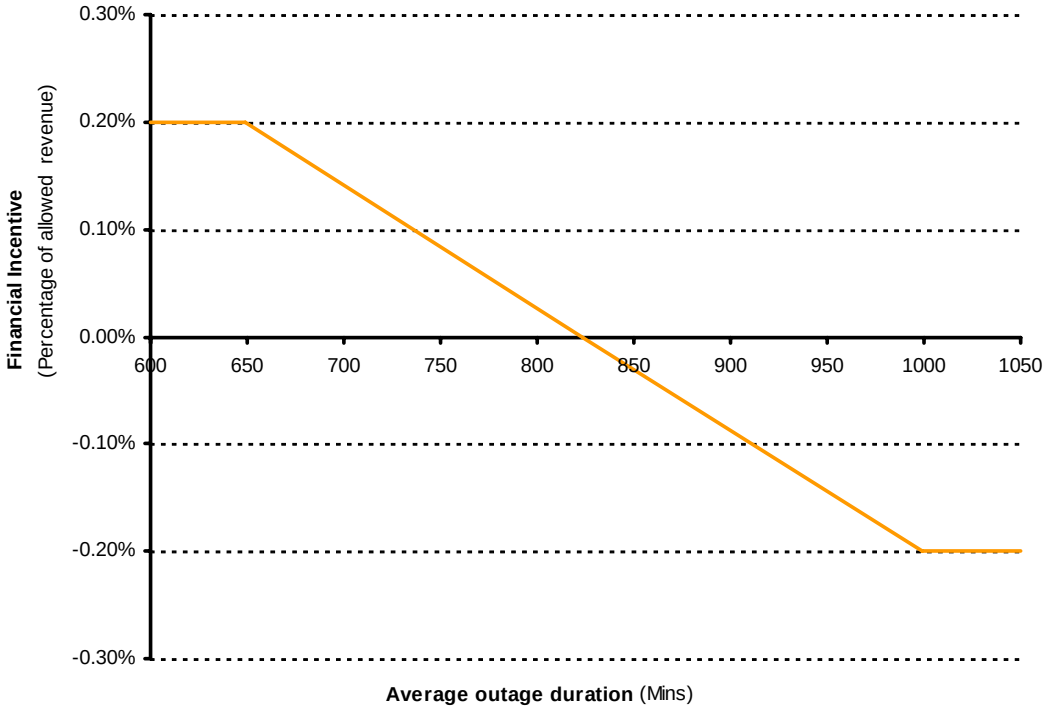


Table G.6: Average outage duration

								Where:				
S6	=	–0.002000							Average outage duration	>	999	
S6	=	–0.000011	x	Average outage duration	+	0.009417	824	≤	Average outage duration	≤	999	
S6	=	–0.000011	x	Average outage duration	+	0.009417	649	≤	Average outage duration	≤	824	
S6	=	0.002000							Average outage duration	<	649	

Appendix H: TransGrid's negotiating framework

Proposed Negotiating Framework for Provision of a Negotiated Transmission Service

1 July 2009 to 30 June 2014

30 May 2008

Table of contents

Background

A. Clause 6A.9.5 of the National Electricity Rules ("NER") provides that:

(a) Transmission Network Service Providers must prepare a document setting out the procedure to be followed during negotiations between that provider and any person who wishes to receive a Negotiated Transmission Service as to the terms and conditions of access for the provision of the service;

(b) the negotiating framework must comply with and be consistent with the applicable requirements of a transmission determination applying to the provider; and

(c) the negotiating framework must comply with and be consistent with the applicable requirements of clause 6A.9.5(c) which sets out the minimum requirements for a negotiating framework.

B. TransGrid is registered with NEMMCO as a Transmission Network Service Provider.

C. This document has been prepared in fulfilment of TransGrid's obligations under clause 6A.9.5 of the NER to establish a negotiating framework.

D. This document applies to TransGrid and any Service Applicant who applies to receive a Negotiated Transmission Service.

E. A Negotiated Transmission Service is any of the following services:

(a) a shared transmission service that:

(1) exceeds the network performance requirements (whether as to quality or quantity) (if any) as that shared transmission service is required to meet under any jurisdictional electricity legislation; or

(2) except to the extent that the network performance requirements which that shared transmission service is required to meet are prescribed under any jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as are set out in schedule 5.1a or 5.1;

(b) connection services that are provided to serve a Transmission Network User or group of Transmission Network Users, at a single transmission network connection point, other than connection services that are provided by one Network Service Provider to another Network Service Provider to connect their networks where neither of the Network Service Providers is a Market Network Service Provider; or

(c) use of system services provided to a Transmission Network User and referred to in rule 5.4A(f)(3) in relation to augmentations or extensions

required to be undertaken on a transmission network as described in rule 5.4A;

but does not include an above-standard system shared transmission service or a market network service.

TransGrid's Negotiating Framework

1. Application of negotiating framework

1.1 This negotiating framework applies to TransGrid and each Service Applicant who has made an application in writing to TransGrid for the provision of a Negotiated Transmission Service.

1.2 TransGrid and any Service Applicant who wishes to receive a Negotiated Transmission Service from TransGrid should comply with the requirements of this negotiating framework.

1.3 The requirements set out in this negotiating framework are additional to any requirements or obligations contained in Chapters 4, 5 and 6A of the NER. In the event of any inconsistency between this negotiating framework and any other requirements in the NER, the requirements of the NER will prevail.

1.4 Nothing in this negotiating framework or in the NER will be taken as imposing an obligation on TransGrid to provide any service to the Service Applicant.

2. Obligation to negotiate in good faith

2.1 TransGrid and the Service Applicant should negotiate in good faith the terms and conditions of access for the provision by TransGrid of the Negotiated Transmission Service sought by the Service Applicant.

2.2 Consistent with Clause 6A.9.1(1) of the NER the price for a *negotiated transmission service* should be based on the costs incurred in providing that service, determined in accordance with the principles and policies set out in the *Cost Allocation Methodology* which has been approved for TransGrid by the Australian Energy Regulator.

3. Timeframe for commencing, progressing and finalising negotiations

3.1 Paragraphs 3.3 and 3.4 set out the timeframe for commencing, progressing and finalising negotiations in relation to applications for Negotiated Transmission Services under Chapter 5 of the NER, and for applications for Negotiated Transmission Services other than under Chapter 5 of the NER respectively.

3.2 The timeframes set out in paragraphs 3.3 and 3.4 may be suspended in accordance with paragraph 8.

3.3 Applications for Negotiated Transmission Services under Chapter 5 of the NER

3.3.1 Where the Negotiated Transmission Service is a service sought under Chapter 5, the specified time for commencing, progressing and finalising negotiations with a Service Applicant for the purposes of clause 6A.9.5 of the Rules is as set out in Chapter 5 of the NER.

3.3.2 TransGrid and the Service Applicant shall use reasonable endeavours to adhere to the time periods specified in paragraph 3.3.1 during the negotiation for the supply of the Negotiated Transmission Service.

3.4 Applications for Negotiated Transmission Services other than under Chapter 5 of the NER

3.4.1 Where the application is in respect of a Negotiated Transmission Service other than a service sought under Chapter 5, the specified time for commencing progressing and finalising negotiations with a Service Applicant for the purposes of clause 6A.9.5 of the NER is as set out in Table 1.

3.4.2 TransGrid and the Service Applicant shall use reasonable endeavours to adhere to the time periods specified in Table 1.

3.4.3 The preliminary program finalised under C in Table 1 may be modified from time to time by agreement of the parties, where such agreement must not be unreasonably withheld. Any such amendment to the preliminary program shall be taken to be a reasonable period of time for commencing, progressing and finalising negotiations with a Service Applicant for the provision of the Negotiated Transmission Service for the purposes of 6A.9.5(5) of the NER. The requirement in paragraph 3.4.2 applies to the last amended preliminary program.

Table 1

	Event	Indicative timeframe
A.	Receipt of written application for a Negotiated Transmission Service	X
B.	Parties meet to discuss a preliminary program with milestones for supply of the Negotiated Transmission Service that represent a reasonable period of time for commencing, progressing and finalising negotiations for the provision of the Negotiated Transmission Service	X + 20 business days
C.	Parties finalise preliminary program, which may include, without limitation, milestones relating to: ▪ the request and provision of commercial information; and ▪ notification and consultation with NEMMCO and / or any affected Transmission Network Users.	X + 30 business days
D.	TransGrid provides Service Applicant with an offer for the Negotiated Transmission Service;	X + 120 business days

	Event	Indicative timeframe
E.	Parties finalise negotiations	X + 160 business days

3.5 Subject to paragraph 3.3 and 3.4, TransGrid and the Service Applicant must, following a request by the Service Applicant, use their reasonable endeavours to:

3.5.1 hold a meeting within 20 Business Days of receipt of the application by the Service Applicant, or such other period as agreed by the parties, in order to agree a timetable for the conduct of negotiations and to commence discussion regarding other relevant issues;

3.5.2 progress the negotiations for the provision of a Negotiated Transmission Service by TransGrid such that the negotiations may be finalised in accordance with paragraph 3.5.1;

3.5.3 adhere to any timetable established for the negotiation and to progress the negotiation in an expeditious manner; and

3.5.4 finalise the negotiations for the provision of a Negotiated Transmission Service by TransGrid within a time period agreed by the parties.

3.6 Notwithstanding paragraph 3.1, or any other provision of this negotiating framework, the timeframes set out in paragraphs 3.3 and 3.4 :

3.6.1 do not commence until payment of the amount to TransGrid pursuant to paragraph 10;

3.6.2 re-commence if there is a material change in the Negotiated Transmission Network service sought by the Service Applicant, unless TransGrid agrees otherwise.

4. Provision of Initial Commercial Information by Service Applicant

Obligation to provide Initial Commercial Information

4.1 Within a time agreed by the parties TransGrid must use its reasonable endeavours to give notice to the Service Applicant requesting Commercial Information held by the Service Applicant that is reasonably required by TransGrid to enable it to engage in effective negotiations with the Service Applicant in relation to the application and to enable TransGrid to submit Commercial Information to the Service Applicant.

4.2 Subject to paragraphs 4.3 and 4.4, the Service Applicant must use its reasonable endeavours to provide TransGrid with the Commercial Information

requested by TransGrid in accordance with paragraph 4.1 within 10 Business Days of that request, or within a time period as agreed by the parties.

4.3 Notwithstanding paragraph 4.1, the obligation under paragraph 4.1 is suspended as at the date of notification of a dispute if a dispute under this negotiating framework arises until conclusion of the dispute in accordance with paragraph 9.

Confidentiality Requirements – Commercial Information

4.4 For the purposes of this paragraph 4, Commercial Information does not include:

4.4.1 confidential information provided to the Service Applicant by another person; or

4.4.2 information that the Service Applicant is prohibited, by law, from disclosing to TransGrid.

4.5 Commercial Information may be provided by the Service Applicant subject to conditions including the condition that TransGrid must not disclose the Commercial Information to any other person unless the Service Applicant consents in writing to the disclosure. The Service Applicant may require TransGrid to enter into a confidentiality agreement, on terms reasonably acceptable to both parties, with the Service Applicant in respect of any Commercial Information provided to TransGrid.

4.6 A consent provided by the Service Applicant in accordance with paragraph 4.5 may be subject to the condition that the person to whom TransGrid discloses the Commercial Information must enter into a separate confidentiality agreement with the Service Applicant.

5. Provision of additional Commercial Information by the Service Applicant

Obligation to provide additional Commercial Information

5.1 TransGrid may give a notice to the Service Applicant requesting the Service Applicant to provide TransGrid with any additional Commercial Information that is reasonably required by TransGrid to enable it to engage in effective negotiations with the Service Applicant in relation to the provision of a Negotiated Transmission Service or to clarify any Commercial Information provided pursuant to paragraph 4.

5.2 The Service Applicant must use its reasonable endeavours to provide TransGrid with the Commercial Information requested by TransGrid in accordance with paragraph 5.1 within 10 Business Days of the date of the request under paragraph 5.1, or such other period as agreed by the parties.

Confidentiality requirements

5.3 For the purposes of this paragraph 5, Commercial Information does not include:

5.3.1 confidential information provided to the Service Applicant by another person; or

5.3.2 information that the Service Applicant is prohibited, by law, from disclosing to TransGrid; and

5.4 Commercial Information may be provided by the Service Applicant subject to conditions including the condition that TransGrid must not disclose the Commercial Information to any other person unless the Service Applicant consents in writing to the disclosure. The Service Applicant may require TransGrid to enter into a confidentiality agreement, on terms reasonably acceptable to both parties, with the Service Applicant in respect of any Commercial Information provided to TransGrid.

5.5 A consent provided by the Service Applicant in accordance with paragraph 5.4 may be subject to the condition that the person to whom TransGrid discloses the Commercial Information must enter into a separate confidentiality agreement with the Service Applicant.

6. Provision of Commercial Information by TransGrid

Obligation to provide Commercial Information

6.1 TransGrid shall provide the Service Applicant with all Commercial Information held by TransGrid that is reasonably required by a Service Applicant to enable it to engage in effective negotiations with TransGrid for the provision of a Negotiated Transmission Service within a timeframe agreed by the parties, including the following information:

6.1.1 a description of the nature of the Negotiated Transmission Service including what TransGrid would provide to the Service Applicant as part of that service;

6.1.2 the terms and conditions on which TransGrid would provide the Negotiated Transmission Service to the Service Applicant;

6.1.3 the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the Negotiated Transmission Service to the Service Applicant which demonstrate to the Service Applicant that the charges for providing the Negotiated Transmission Service reflect those costs and/or the cost increment or decrement (as appropriate).

Confidentiality requirements

6.2 For the purposes of paragraph 6.1, Commercial Information does not include:

6.2.1 confidential information provided to TransGrid by another person; or

6.2.2 information that TransGrid is prohibited, by law, from disclosing to the Service Applicant.

6.3 TransGrid may provide the Commercial Information in accordance with paragraph 6.1 subject to relevant conditions including the condition that the Service Applicant must not disclose the Commercial Information to any other person unless TransGrid consents in writing to the disclosure. TransGrid may require the Service Applicant to enter into a confidentiality agreement with TransGrid, on terms reasonably acceptable to both parties, in respect of Commercial Information provided to the Service Applicant.

6.4 A consent provided by a Service Applicant in accordance with paragraph 6.3 may be subject to the condition that the person to whom the Service Applicant discloses the Commercial Information must enter into a separate confidentiality agreement with TransGrid.

7. Determination of impact on other Transmission Network Users and consultation with affected Transmission Network Users

7.1 TransGrid should determine the potential impact on Transmission Network Users, other than the Service Applicant, of the provision of the Negotiated Transmission Service.

7.2 TransGrid should notify and consult with any affected Transmission Network Users and ensure that the provision of the Negotiated Transmission Service does not result in non-compliance with obligations in relation to other Transmission Network Users under the NER.

8. Suspension of Timeframe for Provision of a Negotiated Transmission Service

8.1 The timeframes for negotiation of provision of a Negotiated Transmission Service as contained within this negotiating framework, or as otherwise agreed between the parties, are suspended if:

8.1.1 within 15 Business Days of TransGrid providing the Commercial Information to the Service Applicant pursuant to paragraph 6.1, the Service Applicant does not formally accept that Commercial

Information and the parties have agreed a date for the undertaking and conclusion of commercial negotiations;

8.1.2 a dispute in relation to the Negotiated Transmission Service has been notified to the AER under clause 6A.30.1, from the date of notification of that dispute to the AER until:

(a) the withdrawal of the dispute under clause 6A.30.1(c) of the NER;

(b) the termination of the dispute by the commercial arbitrator in accordance with clause 6A.30.5(d) or (e) of the NER; or

(c) determination of the dispute by the commercial arbitrator under clause 6A.30.6(b) of the NER;

8.1.3 within 10 Business Days of TransGrid requesting additional Commercial Information from the Service Applicant pursuant to paragraph 5, the Service Applicant has not supplied that Commercial Information;

8.1.4 without limiting paragraphs 8.1.1 to 8.1.3, either of the parties does not promptly conform with any of its obligations as required by this negotiating framework or as otherwise agreed by the parties;

8.1.5 TransGrid has been required to notify and consult with any affected Transmission Network Users under paragraph 7.2 or NEMMCO at any time, from the date of notification to the affected Transmission Network Users or NEMMCO until the end of the time limit specified by TransGrid for any affected Transmission Network Users or NEMMCO, or the receipt of such information from the affected Transmission Network Users or NEMMCO whichever is the later regarding the provision of the Negotiated Transmission Service.

9. Dispute Resolution

9.1 All disputes between the parties as to the terms and conditions of access for the provision of a Negotiated Transmission Service are to be dealt with in accordance with Part K of Chapter 6A of the NER.

10. Payment of TransGrid's Costs

10.1 Prior to commencing negotiations, the Service Applicant shall pay an application fee to TransGrid. Where the application is for a Negotiated Transmission

Service under Chapter 5 of the NER, this payment is made in accordance with clause 5.3.3(c)(5).

10.2 The application fee lodged pursuant to paragraph 10.1 will be deducted from the reasonable Costs incurred in processing the Service Applicant's application to TransGrid for the provision of a Negotiated Transmission Service.

10.3 From time to time, TransGrid may give the Relevant Service Applicant a notice setting out the reasonable Costs incurred by TransGrid and the off-set of any amount applicable under paragraph 10.1.

10.4 If the aggregate of the Costs exceed the amount paid by the Service Applicant pursuant to paragraph 10.1, the Service Applicant must, within 20 Business Days of the receipt of a notice in accordance with paragraph 10.3, pay TransGrid the amount stated in the notice.

10.5 TransGrid may require the Service Applicant to enter into a binding agreement addressing conditions, guarantees and other matters in relation to the payment of on-going Costs.

11. Termination of Negotiations

11.1 The Service Applicant may elect not to continue with its application for a Negotiated Transmission Service and may terminate the negotiations by giving TransGrid written notice of its decision to do so.

11.2 TransGrid may terminate a negotiation under this framework by giving the Service Applicant written notice of its decision to do so where:

11.2.1 TransGrid believes on reasonable grounds that the Service Applicant is not conducting the negotiation under this negotiating framework in good faith;

11.2.2 the Service Applicant consistently fails to comply with the requirements of the negotiating framework;

11.2.3 the Service Applicant fails to comply with an obligation in this negotiating framework to undertake or complete an action within a specified or agreed timeframe, and does not complete the relevant action within 20 Business Days of a written request from TransGrid;

11.2.4 An act of Solvency Default occurs in relation to the Service Applicant.

12. Giving notices

12.1 A notice, consent, information, application or request that must or may be given or made to a party under this document is only given or made if it is in writing and delivered or posted to that party at its address set out below.

If a party gives the other party 5 Business Days' notice of a change of its address, a notice, consent, information, application or request is only given or made by that other party if it is delivered or posted to the latest address.

TransGrid

Name:	TransGrid
Address:	201 Elizabeth Street (cnr Park Street) Sydney NSW 2000

Service Applicant

Name:	Service Applicant
Address:	The nominated address of the Service Applicant provided in writing to TransGrid as part of the application

Time notice is given

12.2 A notice, consent, information, application or request is to be treated as given or made at the following time:

12.2.1 if it is delivered, when it is left at the relevant address; or

12.2.2 if it is sent by post, 2 Business Days after it is posted.

12.2.3 If sent by facsimile transmission, on the day the transmission is sent (but only if the sender has a confirmation report specifying a facsimile number of the recipient, the number of pages sent and the date of transmission); or.

12.2.4 If sent by email once acknowledged as received by the addressee.

12.3 If a notice, consent, information, application or request is delivered after the normal business hours of the party to whom it is sent, it is to be treated as having been given or made at the beginning of the next Business Day.

13. Definitions and interpretation

Definitions

13.1 In this document the following definitions apply:

Business Day means a day on which all banks are open for business generally in Sydney, New South Wales.

Commercial Information shall include at a minimum, the following classes of information:

- details of corporate structure;
- financial details relevant to creditworthiness and commercial risk;
- ownership of assets;
- technical information relevant to the application for a Negotiated Transmission Service;
- financial information relevant to the application for a Negotiated Transmission Service;
- details of an application's compliance with any law, standard, NER or guideline.

Costs means any costs or expenses incurred by TransGrid in complying with this negotiating framework or otherwise advancing the Service Applicant's request for the provision of a Negotiated Transmission Service.

TransGrid trades under it's own name, ABN 19 622 755 774.

Solvency Default means the occurrence of any of the following events in relation to the Service Applicant:

(a) An originating process or application for the winding up of the Service Applicant (other than a frivolous or vexatious application) is filed in a court or a special resolution is passed to wind up the Service Applicant, and is not dismissed before the expiration of 60 days from service on the Service Applicant;

(b) A receiver, receiver and manager or administrator is appointed in respect of all or any part of the assets of the Service Applicant, or a provisional liquidator is appointed to the Service Applicant;

(c) A mortgagee, chargee or other holder of security, by itself or by or through an agent, enters into possession of all or any part of the assets of the Service Applicant;

(d) A mortgage, charge or other security is enforced by its holder or becomes enforceable or can become enforceable with the giving of notice, lapse of time or fulfilment of a condition;

(e) The Service Applicant stops payment of, or admits in writing its inability to pay, its debts as they fall due;

(f) The Service Applicant applies for, consents to, or acquiesces in the appointment of a trustee or receiver of the Service Applicant or any of its property;

(g) A court appoints a liquidator, provisional liquidator, receiver or trustee, whether permanent or temporary, of all or any part of the Service Applicant's property;

(h) The Service Applicant takes any step to obtain protection or is granted protection from its creditors under any applicable legislation or a meeting is convened or a resolution is passed to appoint an administrator or controller (as defined in the *Corporations Act 2001*), in respect of the Service Applicant;

(i) A controller (as defined in the *Corporations Act 2001*) is appointed in respect of any part of the property of the Service Applicant;

(j) Except to reconstruct or amalgamate while solvent, the Service Applicant enters into or resolves to enter into a scheme of arrangement, compromise or reconstruction proposed with its creditors (or any class of them) or with its members (or any class of them) or proposes re-organisation, re-arrangement moratorium or other administration of the Service Applicant's affairs;

(k) The Service Applicant is the subject of an event described in section 459C(2)(b) of the *Corporations Act 2001*; or

(l) Anything analogous or having a substantially similar effect to any of the events specified above happens in relation to the Service Applicant.

Interpretation

13.2 In this document, unless the context otherwise requires:

13.2.1 terms defined in the NER have the same meaning in this negotiating framework;

13.2.2 a reference to any law or legislation or legislative provision includes any statutory modification, amendment or re-enactment, and any subordinate legislation or regulations issued under that legislation or legislative provision;

13.2.3 a reference to any agreement or document is to that agreement or document as amended, novated, supplemented or replaced from time to time;

13.2.4 a reference to a paragraph, part, schedule or attachment is a reference to a paragraph, part, schedule or attachment of or to this document unless otherwise stated;

13.2.5 an expression importing a natural person includes any company, trust, partnership, joint venture, association, corporation, body corporate or governmental agency; and

13.2.6 a covenant or agreement on the part of two or more persons binds them jointly and severally.

Appendix I: Negotiated transmission service criteria

National electricity objective

1. The terms and conditions of access for a negotiated transmission service, including the price that is to be charged for the provision of that service and any access charges, should promote the achievement of the national electricity objective.

Criteria for terms and conditions of access

Terms and conditions of access

2. The terms and conditions of access for a negotiated transmission service must be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER.
3. The terms and conditions of access for a negotiated transmission service (including, in particular, any exclusions and limitations of liability and indemnities) must not be unreasonably onerous taking into account the allocation of risk between the TNSP and the other party, the price for the negotiated transmission service and the costs to the TNSP of providing the negotiated transmission service.
4. The terms and conditions of access for a negotiated transmission service must take into account the need for the service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER.

Price of services

5. The price for a negotiated transmission service must reflect the costs that the TNSP has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the Cost Allocation Methodology.
6. Subject to criteria 7 and 8, the price for a negotiated transmission service must be at least equal to the avoided cost of providing that service but no more than the cost of providing it on a stand alone basis.
7. If the negotiated transmission service is a shared transmission service that:
    i. (i) exceeds any network performance requirements which it is required to meet under any relevant electricity legislation; or
    ii. (ii) exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER

    then the difference between the price for that service and the price for the shared transmission service which meets network performance requirements must reflect the TNSP's incremental cost of providing that service (as appropriate).

8. If the negotiated transmission service is the provision of a shared transmission service that does not meet or exceed the network performance requirements, the difference between the price for that service and the price for the shared transmission service which meets, but does not exceed, the network performance requirements should reflect the amount of the TNSP's avoided cost of providing that service (as appropriate).

9. The price for a negotiated transmission service must be the same for all Transmission Network Users unless there is a material difference in the costs of providing the negotiated transmission service to different Transmission Network Users or classes of Transmission Network Users.

10. The price for a negotiated transmission service must be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person, in which case such adjustment must reflect the extent to which the costs of that asset is being recovered through charges to that other person.

11. The price for a negotiated transmission service must be such as to enable the TNSP to recover the efficient costs of complying with all regulatory obligations associated with the provision of the negotiated transmission service.

Criteria for access charges

Access charges

Any access charges must be based on costs reasonably incurred by the TNSP in providing Transmission Network User access and (in the case of compensation referred to in clauses 5.4A(h) to (j) of the NER) on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to in clauses 5.4A(h) to (j) of the NER where an event referred to in those paragraphs occurs (as appropriate).