Final Decision

Transend
Transmission Determination
2009–10 to 2013–14

28 April 2009

AUSTRALIAN
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Contents

Shortened forms

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AP	Australian Paper
AR	allowed revenue
Aurora	Aurora Energy
BPO	base planning object
capex	capital expenditure
CPI	consumer price index
DNSP	distribution network service provider
DRP	*Draft statement of principles for the regulation of transmission revenues, 27 May 1999*
EUAA	Energy Users Association of Australia
FDC	finance during construction
GWh	gigawatt hour
Hydro	Hydro Tasmania
kV	kilovolt (one thousand volts)
MAR	maximum allowed revenue
MEG	Major Employers Group
MVA	megavolt ampere
MW	megawatt (one thousand kilowatts)
MWh	megawatt hour
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules

NPV	net present value
opex	operating and maintenance expenditure
POE	probability of exceedence
PPI	producer price index
PTRM	post-tax revenue model
RAB	regulated asset base
RFM	roll forward model
RTA	Rio Tinto Alcan
SRP	*Statement of principles for the regulation of electricity transmission revenues*, 8 December 2004
SAE	scope and estimate
TEC	Tasmanian Electricity Code
the current regulatory control period	1 January 2004 to 30 June 2009
the next regulatory control period	1 July 2009 to 30 June 2014
TNSP	transmission network service provider
WACC	weighted average cost of capital
WorleyParsons	WorleyParsons Services Pty Ltd

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).

Transend submitted its revenue proposal, proposed negotiating framework and proposed pricing methodology for the 1 July 2009 to 30 June 2014 regulatory control period to the AER on 31 May 2008, seeking revenues of $1,141.1 million.[1]

The AER released its draft decision on 21 November 2008. The AER was not satisfied that all aspects of Transend's revenue proposal were consistent with the requirements of the NER, and proposed to allow total revenues for Transend of $1,043.1 million. In the draft decision the AER noted that Transend had overspent its capital expenditure allowance for the current period. The draft decision proposed to allow projected expenditure of $415 million. Based on updated data for actual expenditure incurred, work-in-progress and inflation the final decision has reduced this allowance to $386 million.

Transend submitted a revised revenue proposal on 14 January 2009, as is permitted by the NER. A revised revenue proposal may only incorporate revisions to make changes required by, or to address matters raised in a draft decision. Although Transend accepted much of the draft decision, in its revised revenue proposal Transend sought to reinstate its claim for additional capital expenditure to address its program of equipment renewal and replacement, amongst other matters.

Following the release of its draft decision the AER held a public consultation meeting in Hobart in December 2008. That meeting was well attended by numerous stakeholders including major energy users in Tasmania. Subsequently many stakeholders made formal submissions to the AER's process and those submissions are discussed in detail throughout the final decision. A theme of a number of submissions was that economic circumstances had changed rapidly as a consequence of the Global Financial Crisis and the AER's final decision should, where possible, take the changed economic circumstances into account. Within the NER framework the AER has taken into account updated input and other relevant costs to ensure the required allowance meets the NER objectives. These matters are discussed in detail in chapters 4 and 6 and the appendices.

This final decision allows revenues for Transend that increase from $164.7 million in 2009–10 to $222.4 million in 2013–14 and approved a total maximum allowed revenue (MAR) of $962.3 million for the next regulatory control period. The AER's process has therefore resulted in some downward adjustment to the amounts approved between the draft and final decisions. Although some additional capital and operating expenditure has been allowed in response to the revised proposal, the final review of labour and material escalations has produced offsetting reductions in the final amounts approved. There remains a net reduction in these allowances when compared to the draft decision. The reductions in the capital and operating expenditure

[1] All figures in this overview are in nominal dollars unless stated otherwise.

allowances result from the lower estimates of labour and material costs that have emerged since the draft decision. In addition, a lower cost of capital, reflecting weaker economic conditions, has resulted in lower required revenues in the next regulatory control period.

In its May 2008 revenue proposal (original revenue proposal) Transend's forecast capex proposal was $681 million ($2008–09). In the draft decision the AER reduced this to $615 million. Following the AER draft decision, Transend revised its forecast capex proposal to $711 million. While this revised forecast reflected some of the adjustments made in the AER draft decision, Transend also included revised forecasts for some projects where the AER had concluded in the draft decision that it was not satisfied with the project scope and estimates. Taking into consideration the additional information provided by Transend in its revised revenue proposal, the AER has approved a forecast capex allowance of $607 million for Transend over the next regulatory control period. In addition, the AER has provided an indicative contingent project allowance of $412 million.

In its original revenue proposal Transend's forecast opex proposal was $280 million ($2008–09). In the draft decision the AER reduced this to $260 million. In response to matters raised in the AER draft decision, Transend revised its forecast opex proposal back to $283 million. After considering the additional information in Transend's revised revenue proposal, the AER has approved a forecast opex allowance of $254 million. This amount represents an increase of 20 per cent compared with Transend's level of opex in the last five years. The increase in forecast opex is largely driven by the condition of Transend's assets, cost increases and the growth of the asset base over the next regulatory control period.

The revenues allowed in this final decision provide for increasing investment and refurbishment of Transend's transmission network as assets reach the end of their useful lives, so that reliability and security of supply can be maintained throughout the forthcoming regulatory control period. In particular, Transend has been subject to increased jurisdictional network reliability standards since 1 January 2008. As a result, meeting these requirements continues to be a major driver of capital expenditure (capex) for the 2009–10 to 2013–14 regulatory control period.

Other major capital projects Transend plans to undertake in the 2009-14 period will involve new Aurora connection point requests such as those for the Hobart eastern shore, and the Wynyard and Newstead substations. Transend will also undertake a number of augmentation projects including:

- Waddamana-Lindisfarne 220 kV transmission line and substation
- Norwood-Mowbray 110 kV transmission line and
- George Town substation 220 kV security upgrade.

Transend is subject to the AER's service target performance incentive scheme, which encourages TNSPs to improve or maintain their service performance levels against measures of network security and reliability (known as parameters). This final decision includes performance targets for the seven parameters and sub-parameters currently applying to Transend under the scheme. These performance targets are higher than those that applied during Transend's current regulatory period. The increased capex associated with Transend's need to meet the new standards specified in the Tasmanian Electricity Code (TEC) is also expected to deliver increased reliability and security of supply for customers in Tasmania during the next regulatory period.

The AER has estimated that, in nominal terms, the revenue increase during the next regulatory control period consists of an initial increase of 13.9 per cent from 2008-09 to 2009–10 and then a 7.8 per cent increase for each subsequent year of the next regulatory control period. This is equivalent to an annual average increase of 9.0 per cent from the last year of the current regulatory period to the end of the next regulatory period.

The increase in the average transmission charges is greater than the average growth in the level of peak demand in Tasmania, which is forecast to increase by 1.9 per cent per annum over the next regulatory control period. The increase in average transmission charges is primarily because of:

- a higher opening RAB than was forecast in the 2003 revenue cap decision
- the need to replace and maintain ageing assets
- the need for increased capex associated with the new reliability standards specified in the revised Tasmanian Electricity Code
- 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 12 per cent on average of end user electricity charges in Tasmania. The increase proposed in Transend's revised revenue proposal would have resulted in a $37 increase in 2009-10 and $13 for each subsequent year of the regulatory control period. The AER estimates, in nominal terms, that the rise in average transmission charges under this final decision will result in an increase to the average medium residential customer's annual bill of $1 400 by around $18.44 in the first year and $9.52 for each following year of the regulatory period. This equates to an increase of approximately $11.31 or 6.0 per cent per year.

Summary

Under chapter 6A of the NER the AER must make transmission determinations for TNSPs in respect of both prescribed and negotiated transmission services. This decision is the AER's final decision on the transmission determination that will apply to Transend for the regulatory control period 1 July 2009 to 30 June 2014.

This final decision on the transmission determination for Transend should be read in conjunction with the AER draft decision on the transmission determination for Transend, together with the consultants' reports. Except as specified in this final decision, the AER maintains its conclusions set out in the draft decision.

The key components of this final decision are:

- The AER's final revenue determination for Transend in respect of the provision by Transend of prescribed transmission services, including:
  - confirmation of the prudence of capex undertaken by Transend during the current regulatory period,
  - the opening RAB value for Transend
  - an assessment of the forecast capex allowance for Transend over the next regulatory control period
  - an estimate of the efficient benchmark WACC for Transend
  - an assessment of the forecast opex allowance for Transend over the next regulatory control period
  - an assessment of the methodology to determine the caps and collars for the loss of supply parameters that apply under the service target performance incentive scheme
  - the amount of the estimated maximum allowed revenue over the next regulatory control period.
- The AER's final determination on Transend's negotiating framework for negotiated transmission services.
- The AER's final determination on the negotiated transmission service criteria that will apply to Transend.
- The AER's final determination on Transend's pricing methodology.

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

Past capital expenditure

AER draft decision

In the draft decision the AER determined that Transend's expenditure of $415 million on commissioned assets during the current regulatory period and $55 million of its assets under construction were prudent. The AER also determined that allowances for finance during construction (FDC) costs of $26 million for commissioned assets and $1.3 million for assets under construction should be included in Transend's RAB.

Transend revised proposal

Transend has implemented all aspects of the AER draft decision. It has also included the actual capex for 2007-08 of $60 million and an updated estimate for 2008-09 of $80 million along with updated forecasts of assets under construction in the current regulatory period in establishing its past capex of $387 million.

AER conclusion

As part of finalising its decision on the amount of capex to be included in the RAB, the AER stated that it would update the roll forward of Transend's RAB with the actual capex for 2007–08, and the most recent capex estimates for the final year (2008–09) of the current regulatory period along with the latest consumer price index (CPI) data. The capex spend for the current regulatory period is summarised in table 1.

Table 1: Transend's past capital expenditure for the current regulatory control period ($m, nominal)

	2004 (Jan to Jun)	2004–05	2005–06	2006–07	2007–08	2008–09	Total
AER Draft Decision	29.9	52.3	67.6	96.8	71.5	96.4	414.5
Transend Revised Proposal	29.9	52.3	67.6	96.8	59.6	80.4	386.6
AER Final Decision	29.9	52.3	67.6	96.8	59.6	79.7	385.9

Opening asset base

AER draft decision

Based on the roll forward methodology, the AER determined Transend's opening RAB to be $994 million for the next regulatory control period (as at 1 July 2009) using the 2007-08 and 2008-09 estimated capex values and forecast CPI for March 2009.

Transend revised proposal

Transend's revised opening RAB for the next regulatory control period is $961 million.

AER conclusion

Using the updated values for commissioned assets and assets under construction, the AER's application of the roll forward methodology has determined that Transend's opening RAB is $951 million for the next regulatory control period (as at 1 July 2009). The AER's RAB roll forward calculations are set out in table 2.

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

	2004 (Jan to Jun)	2004–05	2005–06	2006–07	2007–08	2008–09[a]
Opening RAB	603.6	628.7	696.1	737.3	811.4	850.5
Forecast capex (adjusted for actual CPI)[b]	28.6	84.4	56.0	95.1	46.0	40.0
Straight-line depreciation (adjusted for actual CPI)	–3.5	–17.0	–14.8	–21.0	–6.9	–6.0
Closing RAB	628.7	696.1	737.3	811.4	850.5	884.5
Add: prudent capex over 2003 decision[c]						33.8
Add: return on difference[d]						–5.9
Add: prudent assets under construction						55.3
Opening RAB at 1 July 2009						951.4

(a) Updated with actual CPI for 2007–08 (March to March).
(b) 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.
(c) Includes the difference between actual and forecast capex for the $16.8 million underspend from 1 July to 31 December 2003 and a $50.6 million overspend from 1 January 2004 to 30 June 2009. The cash values for disposal of assets have been deducted.
(d) This relates to the return on difference between actual and forecast capex for the period 1 July 2003 to 31 December 2003.

Forecast capex expenditure

AER draft decision

In the draft decision the AER did not accept Transend's proposed ex ante capex allowance of $681 million ($2008–09) and explained the reasons in respect of the proposal not meeting the capex criteria under clause 6A.6.7(c) of the NER. The AER made several adjustments to Transend's proposal and considered that an ex ante forecast capex allowance of $615 million represented the total capex that a prudent operator in the circumstances of Transend would require to achieve the capex objectives. In addition, the AER approved an indicative contingent projects allowance of $412 million.

Transend revised proposal

Transend has implemented the AER draft decision in respect of forecast capex except those related to:

- renewal capex projects
- labour and non-labour cost escalation
- contingent projects.

Transend has also proposed moving the second Waddamana–Lindisfarne 220 kV transmission line second circuit project from contingent project to ex ante capex.

Transend's revised ex ante capex proposal is $711 million ($2008–09). Its revised revenue proposal includes 8 contingent projects. The total indicative cost for these projects is $390 million.

AER conclusion

The AER is not satisfied that the revised total forecast capex proposed by Transend reasonably reflects the capex criteria under clause 6A.6.7(c). The AER is therefore required under clause 6A.14.1(2)(ii) to provide an estimate of the total capex that Transend will require over the next regulatory control period which the AER is satisfied reasonably reflects the capex criteria, taking into account the capex factors set out in clause 6A.6.7(e).

The AER has considered the analysis and advice of Nuttall Consulting and has reduced Transend's revised ex ante capex proposal by $42 million ($2008–09). The AER also updated cost escalation factors which further reduced the total by $63 million. This represents a total reduction of $105 million or almost 15 per cent of Transend's revised forecast capex allowance. The AER's amended ex ante capex allowance for the next regulatory control period is $606 million and is set out in table 3 along with the adjustments made to Transend's revised capex proposal. In addition, the AER has approved an indicative contingent projects allowance of $412 million.

This amended allowance represents the AER's estimate of the total capex that a prudent operator in the circumstances of Transend would require to achieve the capex objectives. The AER is satisfied that the amended ex ante capex allowance of $606 million over the next regulatory control period, reasonably reflects the capex criteria, taking into account the capex factors.

Table 3: AER's conclusion on Transend's ex ante allowance ($m, 2008–09)

	2009–10	**2010–11**	**2011–12**	**2012–13**	**2013–14**	**Total**
Transend's proposal (31 May 2008)	158.0	173.4	106.5	118.5	124.3	680.7
AER Draft Decision	154.6	166.6	101.2	96.8	96.0	615.1
Transend's revised proposal (14 January 2009)	181.8	187.6	105.7	116.9	118.7	710.8
Adjustment resulting from detailed project reviews	–8.5	–11.8	–1.2	–8.8	–11.6	–41.9
Application of annual escalators	–14.8	–18.7	–10.8	–9.4	–9.3	–63.1
AER's total adjustments	–23.3	–30.5	–11.9	–18.3	–20.4	–104.4
AER's ex ante capex allowance	**158.5**	**157.1**	**93.8**	**98.6**	**98.4**	**606.4**

Note: Total may not add up due to rounding.

Cost of capital

AER draft decision

In the draft decision the AER determined a nominal vanilla WACC for Transend of 9.64 per cent. The AER noted that it would update the values of the risk-free rate and debt risk premium to reflect more current market data, based on the agreed averaging period, at the time of its final decision.

Transend revised proposal

Transend recognised that the risk-free rate and debt risk premium would be updated for the AER's final decision using the averaging period requested by Transend on a confidential basis. Subject to these changes being made in the final decision, Transend has implemented all aspects of the AER draft decision with the exception of the expected inflation rate.

AER conclusion

The AER has determined a nominal vanilla WACC of 8.80 per cent for Transend, based on the updated risk-free rate and debt risk premium, and other parameters prescribed by the NER. Table 4 sets out the WACC parameter values for this final decision.

Table 4: AER's conclusion on WACC parameters

Parameter	AER's Conclusion
Risk–free rate (nominal)	4.30%
Risk–free rate (real)	1.78%
Expected inflation rate	2.47%
Debt risk premium	3.49%
Market risk premium	6.00%
Gearing	60%
Equity beta	1
Nominal pre–tax return on debt	7.79%
Nominal post–tax return on equity	10.30%
Nominal vanilla WACC	8.80%

(a) The real risk-free rate was derived using the Fisher equation.

The AER has applied a methodology to determine a forecast inflation rate over a 10-year period by referencing the Reserve Bank of Australia's (RBA) inflation forecasts for the first two years and the mid-point of the RBA's target inflation range for the remaining eight years. The AER considers that, based on a simple average, an inflation forecast of 2.47 per cent per annum produces the best estimate of a 10-year inflation forecast to be applied in the post-tax revenue model.

Operating and maintenance expenditure

AER draft decision

In the draft decision the AER rejected Transend's forecast opex requirement of $281 million ($2008–09) and explained the reasons in respect of the proposal not meeting the opex criteria under clause 6A.6.6(c) of the NER. The AER substituted a forecast opex requirement of $260 million which represented the total opex costs that a prudent operator in the circumstances of Transend would require to achieve the opex objectives.

Transend revised proposal

Transend has implemented the AER draft decision in respect of forecast opex except those related to:

- debt and equity raising costs
- labour and non labour escalators
- labour escalation for telecommunication costs.

Transend's revised opex forecast proposal is $283 million ($2008–09).

AER conclusion

The AER is not satisfied that Transend's total forecast opex reasonably reflects the opex criteria under clause 6A.6.6(c). The AER is therefore required under clause 6A.14.1(3)(ii) to provide an estimate of the total opex that Transend will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors set out in clause 6A.6.6(e).

On the basis of its analysis of Transend proposed opex forecast and the advice of Econtech and Nuttall Consulting, the AER has applied a reduction of $29 million ($2008–09) to Transend's revised proposed opex. This results in an amended forecast opex allowance of $254 million for the next regulatory control period is as shown in table 5.

Table 5: AER's conclusion on Transend's total opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER's total opex allowance (draft decision)	50.3	51.0	50.9	53.8	54.2	260.2
Transend's revised proposed total opex	54.2	55.6	55.6	58.7	59.2	283.3
Adjustment to equity raising costs – capex[a]	-2.3	-2.3	-2.3	-2.3	-2.3	11.4
Adjustments arising from modelling[b]	-2.3	-3.0	-3.4	-4.1	-4.9	-17.6
AER's total adjustments	-4.6	-5.2	-5.6	-6.4	-7.2	-29.0
AER's total opex allowance	49.7	50.3	50.0	52.3	52.0	254.3

(a) These adjustments reflect changes to asset growth (resulting from amended capex allowance), actual CPI for 2007–08 and 2008–09, removal of replacement capex for transitional services, and debt raising costs (resulting from amended capex allowance).

This amended allowance represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of Transend would require to achieve the opex objectives. The AER is satisfied that the amended total forecast opex of $254 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors.

Efficiency Benefits Sharing Scheme

AER draft decision

In the draft decision the AER rejected Transend's proposed exclusion of redundancy costs from the EBSS and accepted debt and equity raising costs, insurance, self-insurance and superannuation provision should be excluded.

Transend revised proposal

Transend has implemented all aspects of the AER draft decision.

AER conclusion

The AER confirms the draft decision's conclusions on the EBSS. The AER has updated the controllable opex for EBSS purposes for the changes that have occurred in the opex section in table 6.

Table 6: Transend's forecast controllable opex for EBSS purposes ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14
Total forecast opex	**49.7**	**50.3**	**50.0**	**52.3**	**52.0**
Debt and equity raising costs	0.5	0.5	0.6	0.6	0.6
Insurance and self-insurance costs	1.8	1.8	1.9	2.1	2.2
Superannuation provisions	0.0	0.0	0.0	0.0	0.0
Non-network alternatives	3.9	2.6	0.0	0.0	0.0
Forecast opex for EBSS purposes	**43.5**	**45.3**	**47.4**	**49.7**	**49.2**

Service target performance incentive

AER draft decision

In the draft decision the AER rejected many elements of Transend's service target performance incentive proposal including the use of deadbands on all targets. Table 7 sets out the AER's draft decision's conclusions on performance targets, caps, collars and weightings for each parameter that applies to Transend.

Table 7: Caps, collars, targets and weightings to apply to Transend

Parameter	Recommended values			
	Collar	Target	Cap	Weighting
Circuit availability (%)				*MAR (%)*
Transmission circuit availability (critical)	97.90	99.13	99.75	0.20
Transmission circuit availability (non-critical)	98.48	98.97	99.47	0.10
Transformer circuit availability	98.67	99.28	99.90	0.15
Loss of supply event frequency (no.)				*MAR (%)*
> 0.1 (x) system minutes	21	15	8	0.20
> 1.0 (y) system minutes	4	2	0	0.35
Average outage duration (minutes)				*MAR (%)*
Transmission Lines	259	326	124	0.0
Transformers	1428	712	354	0.0

Transend revised proposal

Transend has implemented all aspects of the AER draft decision with the exception of changes to the caps for transformer circuit availability and loss of supply > 0.1 system minutes. Transend has proposed the cap for the transformer circuit availability measure be 99.59 per cent and the cap for loss of supply > 0.1 system minutes be 9 events. Transend has provided the methodologies for calculating these caps.

Transend also proposed to be able to opt into the market impact of transmission congestion (MITC) parameter.

AER conclusion

The AER confirms the conclusions from the draft decision for the caps, collars, performance targets and weightings to be applied to Transend during the next regulatory control period with the exception of the cap for the loss of supply >0.1 system minutes. The AER has accepted Transend alteration to the methodology applied in the draft decision as reasonable. The AER rejects the alteration to the cap for the transformer circuit availability measure proposed by Transend.

The AER has also rejected Transend's proposal to be able to opt into the MITC during the next regulatory period as they are specifically excluded under the scheme from having the MITC apply to them and under the rule 6A.7.4(f) the guidelines cannot be changed until the next regulatory period.

Table 8: Caps, collars, targets and weightings to apply to Transend

Parameter	**Recommended values**			
	Collar	**Target**	**Cap**	**Weighting**
Circuit availability (%)				*MAR (%)*
Transmission circuit availability (critical)	97.90	99.13	99.75	0.20
Transmission circuit availability (non-critical)	98.48	98.97	99.47	0.10
Transformer circuit availability	98.67	99.28	99.90	0.15
Loss of supply event frequency (no.)				*MAR (%)*
> 0.1 (x) system minutes	21	15	9	0.20
> 1.0 (y) system minutes	4	2	0	0.35
Average outage duration (minutes)				*MAR (%)*
Transmission Lines	259	326	124	0.0
Transformers	1428	712	354	0.0

Maximum allowed revenue

AER draft decision

In the draft decision the AER determined an annual building block revenue requirement for Transend that increased from $176 million in 2008–09 to $240 million in 2013–14 ($nominal). The net present value (NPV) of the annual building block revenue requirement for the next regulatory control period was calculated to be $787 million. Based on this NPV amount, the AER determined a nominal expected MAR (smoothed) for Transend that increases from $176 million in 2008–09 to $244 million in 2013–14. The maximum allowed revenue for Transend over the next regulatory control period was calculated to be $1044 million.

Transend revised proposal

Transend stated that it has applied the post-tax building block approach to calculate its proposed revenues. Transend's proposed revenues were determined on the basis of an opening RAB of $961 million. It requested nominal unsmoothed revenues of $181 million in 2008–09, increasing to $255 million in 2013–14. Transend's MAR for the final year of its current regulatory period (2008–09) is $145 million.

AER conclusion

The AER has determined an annual building block revenue requirement for Transend that increases from $165 million in 2008–09 to $219 million in 2013–14 ($nominal).

The NPV of the annual building block revenue requirement for the next regulatory control period has been calculated to be $743 million. Based on this NPV amount, the AER has determined a nominal expected MAR (smoothed) for Transend that increases from $165 million in 2008–09 to $222 million in 2013–14, as shown in table 9. The MAR for Transend over the next regulatory control period is $962 million.

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 –5.19 per cent in subsequent years. The AER's revenue determination for Transend is set out in part 1 of the transmission determination.

Transend's MAR for the next regulatory control period is established through a building block approach. While the AER assesses Transend's proposed pricing methodology, actual transmission charges established at particular connection points are not approved by the AER. Transend establishes its transmission charges in accordance with its approved pricing methodology and the NER.

Table 9: AER's final decision on the maximum allowed revenue ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Return on capital	83.7	96.2	108.7	115.8	123.3	527.6
Regulatory depreciation	26.3	27.7	22.8	27.3	30.8	134.8
Opex allowance	50.9	52.9	53.8	57.7	58.8	274.0
Opex efficiency (glide path) allowance[a]	0.0	0.0	0.0	0.0	0.0	0.0
Net tax allowance	3.8	4.4	5.0	5.6	6.2	25.0
Annual building block revenue requirement (unsmoothed)	164.7	181.1	190.3	206.5	219.0	961.5
MAR (smoothed)	164.7	177.5	191.4	206.3	222.4	962.3
X factor	–[a]	–5.19 %	–5.19 %	–5.19%	–5.19 %	–

(a) An allowance for opex efficiency resulting in the current regulatory period.

The effect of the AER's final decision on average transmission charges can be estimated by taking the annual MAR and dividing it by forecast annual energy delivered in Tasmania. Based on this approach, the AER estimates that this final decision will result in an 6.0 per cent per annum (nominal) increase in average transmission charges over the next regulatory control period or an increase of 3.5 per cent per annum in real terms ($2008–09). The AER estimates that the increase in average transmission charges for customers under this final transmission determination will add approximately $18 (or 1.3 per cent) in 2009-10, and approximately $9.50 for each subsequent year of the forthcoming regulatory control period to the average residential customer's annual bill.

For comparison, the AER has calculated that under the revised proposal the implied energy delivered unit cost of Transend proposed revised MAR (average transmission charges) is $16.57 per MWh in 2008–09 increasing at a nominal average annual rate of 9.2 per cent to $20.82 per MWh in 2013–14. In nominal terms, the average increase in transmission charges would increase the average residential customer bill of $1 400 by approximately $37.30 in the first year and about $13.20 for each following year. This would be approximately $18 or 8.9 per cent per year over the regulatory period in nominal terms.

Negotiating framework

AER draft decision

The AER assessed Transend's proposed negotiating framework against the NER requirements. The AER determined that Transend's negotiating framework complied with clause 6A.9.5(c) of the NER.

Transend revised proposal

Transend did not address the negotiating framework in its revised revenue proposal.

AER conclusion

The AER has affirmed its draft decision and the negotiating framework set out in part 2 of the transmission determination will apply to Transend for the regulatory control period 1 July 2009 to 30 June 2014.

Negotiated transmission service criteria

AER draft decision

As required by the NER, the AER determined the negotiated transmission service criteria that gave effect to, and were consistent with, the negotiated transmission service principles set out in clause 6A.9.1.

Transend revised proposal

Transend did not address the negotiated transmission service criteria in its revised revenue proposal.

AER conclusion

The AER has affirmed its draft decision and therefore the negotiated transmission service criteria set out in part 3 of the transmission determination will apply to Transend for the regulatory control period 1 July 2009 to 30 June 2014.

Pricing methodology

AER draft decision

In the draft decision the AER assessed Transend's May 2008 proposed pricing methodology against the AER's final pricing methodology guidelines issued on 29 October 2007. While most of the proposed pricing methodology complied, a section did not meet the requirements of the guidelines. Consequently, Transend's proposed pricing methodology was not approved by the AER in its draft decision and Transend was required to submit a revised proposed pricing methodology by 14 January 2009.

Transend revised proposal

On 14 January 2009 Transend submitted its revised proposed pricing methodology to the AER. Transend's revised proposed pricing methodology included several amendments namely:

- the treatment of radial lines
- locational component prices for prescribed TUOS services
- editorial changes and specifying the points in the transmission network where costs will be allocated and prices determined.

The remainder of the proposed pricing methodology remained unchanged from the draft decision. Transend stated that its revised proposed pricing methodology addressed the requirements of the pricing methodology guidelines.

AER conclusion

The AER has considered Transend's revised proposed pricing methodology and request that Transend make several changes to improve the methodology's clarity and to ensure it complies with the guidelines and the NER. The AER is satisfied that Transend's amended revised proposed pricing methodology complies with the NER and the guidelines and therefore approves it, subject to the amendments required in section 12.6 of this final decision.

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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 is required to make a transmission determination in accordance with chapter 6A of the NER in respect of certain services provided by TNSPs. 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 Australian Competition and Consumer Commission (ACCC) determined Transend's current revenue cap for a five-and-a-half-year period from 1 January 2004 to 30 June 2009 (the current regulatory control period) under the National Electricity Code, which has been superseded by the NER.[2]

On 31 May 2008 Transend submitted to the AER its revenue proposal, proposed negotiating framework and proposed pricing methodology for the period 1 July 2009 to 30 June 2014 (the next regulatory control period).[3] On 26 June 2008 the AER published these and the proposed negotiated transmission service criteria for Transend as required by clause 6A.11.3 of the NER. Stakeholders were invited to make a written submission to the AER on Transend's revenue proposal, proposed negotiated framework and the AER's proposed negotiated transmission service criteria.

Rule 6A.12 of the NER requires the AER to consider any written submissions made under clause 6A.11.3 and to make a draft decision. Following publication of the draft decision, the AER was required to hold a predetermination conference and invite submissions on its draft decision.

Transend, in addition to tendering a written submission, is permitted to submit to the AER a revised revenue proposal and a revised proposed negotiated framework (if relevant). In accordance with clause 6A.12.3(b) of the NER, any revised revenue proposal may only make revisions so as to incorporate the substance of any changes required by, or to address matters raised in the draft decision.

[2] ACCC, *Tasmanian transmission network revenue cap 2004–2008/09: Decision*, 10 December 2003.

[3] Transend, *Transend transmission revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014,* 31 May 2008.

On 14 January 2009 Transend submitted its revised revenue proposal to the AER. The AER published Transend's January 2009 revised revenue proposal (revised revenue proposal) as required by clause 6A.12.3(f) of the NER.[4]

Under clause 6A.13.1(a) of the NER, the AER is required to consider any submissions made on its draft decision or on Transend's revised revenue proposal or revised proposed negotiating framework (if relevant) and make a final decision.

1.2 AER draft decision

On 21 November 2008 the AER made its draft decision on Transend's transmission determination.[5] In the draft decision the AER approved a MAR for Transend over the next regulatory control period of $1044 million. The annual maximum allowed revenue (MAR) for Transend increases from $176 million in 2009–10 to $240 million in 2013–14 ($ nominal). Table 1.1 shows the annual building block calculations including the opex efficiency allowance and smoothed MAR.

Table 1.1: AER's draft decision on the maximum allowed revenue ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Return on capital	95.8	109.2	124.3	132.9	141.1	603.2
Regulatory depreciation	24.4	25.0	23.1	26.2	29.9	128.6
Opex allowance	51.6	53.7	54.9	59.5	51.5	281.1
Opex efficiency (glide path) allowance[a]	0.0	0.0	0.0	0.0	0.0	0.0
Net tax allowance	4.6	5.4	6.1	6.7	7.3	30.2
Annual building block revenue requirement (unsmoothed)	176.4	193.3	208.4	225.4	239.8	1043.1
MAR (smoothed)	176.4	191.3	207.4	225.0	244.0	1044.0
X factor	–18.9	–5.8	–5.8	–5.8	–5.8	–

(a) An allowance for opex efficiency resulting in the current regulatory period.

The AER assessed Transend's negotiating framework for negotiated services and, subject to minor drafting amendments agreed between the AER and Transend, considered that the negotiating framework complied with clause 6A.9.5(c) of the NER.

The AER's draft decision approved a forecast capital expenditure (capex) allowance of $615 million ($2008–09), with the indicative cost of approved contingent projects

4 Transend, *Transend transmission revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 14 January 2009.

5 AER, *Transend transmission determination 2008–09 to 2013–14: Draft decision*, 21 November 2008.

totalling $412 million. A total operating and maintenance expenditure (opex) allowance of $260 million for Transend was also approved.

The AER's draft decision approved the values that are to be attributed to the service target performance incentive scheme parameters. Table 1.2 sets out the AER's conclusions on performance targets, caps, collars and weightings for each of the parameters that are to apply to Transend under the performance incentive scheme.

Table 1.2: AER's draft decision on caps, collars, targets and weightings to apply to Transend

Parameter	Recommended values			
	Collar	Target	Cap	Weighting
Circuit availability (%)				*MAR (%)*
Transmission circuit availability (critical)	97.90	99.13	99.75	0.20
Transmission circuit availability (non-critical)	98.48	98.97	99.47	0.10
Transformer circuit availability	98.67	99.28	99.90	0.15
Loss of supply event frequency (no.)				*MAR (%)*
> 0.1 (x) system minutes	21	15	8	0.20
> 1.0 (y) system minutes	4	2	0	0.35
Average outage duration (minutes)				*MAR (%)*
Transmission Lines	259	326	124	0.0
Transformers	1428	712	354	0.0

The AER assessed Transend's negotiating framework for negotiated services and, subject to minor drafting amendments agreed between it and Transend, considered that the negotiating framework complied with clause 6A.9.5(c) of the NER.

The AER draft decision also specified the negotiated transmission service criteria for Transend over the next regulatory control period.

1.3 Transend revised proposal

On 14 January 2009 Transend submitted its revised revenue proposal in accordance with chapter 6A of the NER. This revised revenue proposal indicated where Transend has implemented changes required by the AER's draft decision. Where Transend has not fully accepted the requirements of the draft decision, its revised revenue proposal provided additional information to address the matters raised by the AER and sought to demonstrate that its revised revenue proposal satisfied the requirements of the NER.

Transend's revised revenue proposal sets out a MAR requirement that increases from $181 million in 2009–10 to $255 million in 2013–14 ($nominal) with a total MAR of $1084 million over the next regulatory control period.

Transend's revised opening RAB is $987 million (as at 1 July 2009). Transend has implemented all aspects of the AER's draft decision relating to the opening RAB. In establishing its revised opening RAB proposal, Transend has also included updated data for actual capex in 2007–08, estimates for 2008–09, forecasts of commissioned assets, and assets under construction in the current regulatory control period.

Transend's revised capex forecast for the next regulatory control period is $711 million ($2008–09). Transend has implemented most aspects of the AER's draft decision relating to forecast capex. The exceptions related to:

- the timing of asset renewal projects
- labour cost escalation
- non-labour construction (materials) cost escalation
- contingent projects.

Transend's revised total forecast opex for the next regulatory control period is $283 million ($2008–09). Transend has implemented most aspects of the AER's draft decision relating to forecast opex. The exceptions related to:

- debt raising costs
- equity raising costs
- telecommunication costs.

Transend has implemented most aspects of the AER's draft decision relating to the service target performance incentive scheme. The exception relates to the caps for loss of supply > 0.1 system minutes and transformer circuit availability.

1.4 Review process

Using the review process outlined in part E of chapter 6A of the NER, the AER has assessed Transend's original revenue proposal, proposed negotiating framework and proposed pricing methodology (May 2008), its revised revenue proposal (January 2009) and revised proposed pricing methodology (January 2009). The review process involved:

- Proposal—Transend submitted its revenue proposal, proposed negotiating framework and proposed pricing methodology to the AER on 31 May 2008, 13 months before the end of its current regulatory control period. The AER assessed Transend's proposal against chapter 6A of the NER and the AER's guidelines as set out in appendix A of the final decision.[6]
- Public consultation—The AER published Transend's proposal and the AER's proposed negotiated transmission service criteria for Transend and called for submissions from interested parties. The AER held a public forum on Transend's

[6] AER, *Transend draft decision*, op. cit. p.262.

proposal on 6 August 2008, where Transend and interested parties made presentations.

- Submissions—The AER received five submissions on Transend's proposal and the proposed negotiated transmission service criteria. The parties who tendered submissions were the Energy Users Association of Australia, Australian Paper, Hydro Tasmania, Major Employers Group and Rio Tinto Alcan.
- Assessment by a technical expert—The AER engaged Worley Parsons Services Pty Ltd (WorleyParsons) as a technical expert to advise the AER on a number of key aspects of Transend's original revenue proposal. Specifically, the AER asked WorleyParsons to provide its opinion on:

  - whether the investment processes and procedures adopted by Transend for capex are likely to result in efficient outcomes
  - the prudence of capex undertaken by Transend during the current regulatory period
  - the adequacy, efficiency and appropriateness of the capex projects planned by Transend to meet its present and future service requirements
  - the effectiveness of Transend's operating practices and procedures and asset management system
  - the appropriateness of Transend's methodology to forecast its opex requirements
  - the efficiency of Transend's forecast opex
  - the appropriate performance incentive scheme for service standards.

  WorleyParsons provided its opinion to the AER on these matters. WorleyParsons' advice represents its independent assessment based on its analysis. The terms of reference guiding WorleyParsons' review are summarised in each chapter of its report.[7]

- Additional technical/specialist advice—The AER engaged Nuttall Consulting Pty Ltd (Nuttall Consulting) to provide the AER with technical and engineering advice throughout the review process. Nuttall Consulting assisted the AER in reviewing the renewal capex program along with the technical aspects of material contained in Transend's proposal, submissions and specific aspects of WorleyParsons' report. The AER also engaged Econtech to review forecast Tasmanian labour costs.
- Draft decision—The AER released its draft decision on Transend's transmission determination on 27 November 2008 and the AER requested submissions from interested parties.
- Public consultation—The AER held a predetermination conference on its draft decision on 10 December 2008 to outline and explain its draft decision and receive oral submissions from interested parties.

[7] WorleyParsons, *Review of the Transend transmission network revenue proposal 2009 – 2014: An independent review prepared for the Australian Energy Regulator*, 23 October 2008.

- Revised revenue proposal—Transend submitted its revised revenue proposal on 14 January 2009.
- Revised pricing methodology—Transend submitted its revised proposed pricing methodology to the AER on 14 January 2009.
- Submissions—The AER received nine submissions on Transend's revised revenue proposal. Parties who tendered submissions were the Energy Users Association of Australia, Major Employers Group, Nyrstar, Hydro Tasmania, TransGrid, Powerlink, DA Electricity, Competition Economists Group and Rio Tinto Alcan.
- Assessment by a technical expert—The AER retained Nuttall Consulting to advise the AER in relation to a number of aspects of Transend's revised revenue proposal. Specifically, the AER asked Nuttall Consulting to provide its opinion on:
  - capex issues—Waddamana-Lindisfarne second 220kV line and the Burnie-Sheffield 110kV line augmentation

    —renewal capex
  - opex issues—Telecommunications purchase

  Nuttall Consulting provided its opinion to the AER on these issues and also responded to a number of comments raised in submissions. Nuttall Consulting's advice represents its independent views based on its review. The AER has considered this advice in making its final decision. The terms of reference guiding Nuttall Consulting's review are set out in chapter 1 of its report.[8]
- Final decision—The AER made its final decision on Transend's transmission determination on 28 April 2009.

1.5 Structure of final decision

This final decision sets out the AER's consideration of Transend's revised revenue proposal and revised proposed pricing methodology, including substantive issues raised in submissions. Except as specified in this final decision, the AER maintains its conclusions set out in the draft decision.

The structure of the final decision is set out as follows:

- Chapter 2 confirms the prudence of past capex as determined in the draft decision, incorporating the 2007-08 actual capex values and updated 2008-09 estimates for capex.
- Chapter 3 establishes the opening asset base incorporating the 2007-08 actual capex values and revised 2008-09 values.
- Chapter 4 assesses the efficient forecast capex allowance.
- Chapter 5 determines the benchmark weighted average cost of capital.
- Chapter 6 assesses the efficient forecast opex allowance.
- Chapter 7 confirms the efficiency benefit sharing scheme.

8 Nuttall Consulting, *Review of Transend revised revenue proposal 2009-2014*, April 2009.

- Chapter 8 confirms the service target performance incentive scheme.
- Chapter 9 determines the maximum allowed revenues for the next regulatory control period.
- Chapter 10 confirms the negotiating framework for negotiated transmission services approved in the draft decision.
- Chapter 11 confirms the negotiated transmission service criteria approved in the draft decision.
- Chapter 12 assesses the revised pricing methodology.
- Appendix A sets out the AER's consideration of input (labour and non-labour) real cost escalators.
- Appendix B provides a description of the contingent projects and their triggers.
- Appendix C analyses the risk-free averaging period.
- Appendix D looks at benchmarking of proposed expenditure.
- Appendix E provides a detail analysis of debt and equity raising costs.
- Appendix F sets out the parameter definitions relating to the service target performance incentive scheme.
- Appendix G sets out the curves and formulae for calculating the financial incentive under the service target performance incentive scheme.

2 Past capital expenditure

2.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision on Transend's past capital expenditure (capex), including matters raised by Transend in its January 2009 revised revenue proposal (revised proposal).

2.2 AER draft decision

In the draft decision, the AER determined that Transend's expenditure of $415 million on commissioned assets during the current regulatory period and $55 million on assets under construction was prudent. The AER also determined that allowances for finance during construction (FDC) costs of $26 million for commissioned assets and $1.3 million for assets under construction should be included in Transend's RAB.[9]

2.3 Transend revised proposal

Transend accepted the AER's draft decision that the historical capital expenditure should be added to the regulatory asset base. It has implemented all aspects of the AER draft decision in respect of past capital expenditure and has calculated that its capex for the current regulatory control period is $387 million.[10] In calculating this amount, Transend has applied:

- actual capex for 2007-08 of $60 million
- updated estimate for 2008-09 of $80 million
- updated forecasts of assets under construction in the current regulatory control period.

2.4 Submissions

The EUAA stated that WorleyParsons' ex post review of Transend's capex was methodologically flawed and hence provided no reasonable basis for concluding that the historic overspend was prudent and efficient. [11]

2.5 Issues and AER considerations

2.5.1 Actual capital expenditure for 2007–08

AER draft decision

The AER included in Transend's RAB an allowance of $72 million (exclusive of FDC) for assets commissioned in 2007–08.[12] As part of finalising its decision on the

9 Interest during construction cost is also known as finance during construction.

10 Transend, *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 14 January 2009, p. 21, Appendix 2 – Historic cost templates.

11 EUAA, *Submission to AER on the draft decision on Transend's regulated revenue for the regulatory control period 1 July 2009 to 30 June 2014*, 13 February 2009, p. 6-8.

amount of capex to be included in the RAB, the AER stated that it would update the roll forward of Transend's RAB with the actual capital expenditure for 2007–08.

Transend revised proposal

Transend has provided an updated amount of $56 million (exclusive of FDC) for the commissioning of assets in 2007–08.

AER considerations

The AER has reviewed the actual cost information provided by Transend and considers the amount of $56 million accurately reflects the actual amount of capex commissioned in 2007–08. Using the updated information provided by Transend, the AER has made consequential revisions to the FDC allowances because they are dependent on the amount, asset category and profile of capex to be included in the RAB.[13] Based on the methodology accepted by the AER in the draft decision, the AER considers that the updated capex values result in revised FDC allowances of approximately $4 million for Transend's commissioned assets in 2007-08[14]. The total amount is discussed in section 2.5.2.

2.5.2 Capital expenditure forecast for 2008–09 — update of values

AER draft decision

The AER included in Transend's RAB an allowance of $96 million (exclusive of FDC) for assets commissioned in 2008–09 and $55 million (exclusive of FDC) of assets under construction to be incurred in 2008–09.[15] As part of finalising its decision on the amount of capex to be included in the RAB, the AER stated that it would update the roll forward of Transend's RAB with the most recent capex estimates for the final regulatory year (2008–09) of the current regulatory period and the latest CPI data.[16]

Transend revised proposal

Transend has updated the 2008–09 forecasts for commissioned assets and assets under construction in its revised revenue proposal. The updated forecast value of commissioned assets for 2008–09 is $75 million (exclusive of FDC) and the updated forecast value of assets under construction is $60 million.

AER considerations

The AER has reviewed the updated cost information templates for past capex and the amount of $74 million is considered to provide a better estimate of the value of assets

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12 AER, *Transend transmission determination 2008–09 to 2013–14: Draft decision*, 21 November 2008, p. 56-57.

13 The ACCC's 2003 revenue cap decision recognised Transend's capex on an as-commissioned basis. As such, the ACCC accepted it would be appropriate for capex to include an FDC allowance to provide for the efficient cost of financing projects when they are under construction but not earning revenues.

14 The draft decision accepted the application of an FDC factor of 7.54 per cent to determine the FDC allowance for Transend's commissioned assets. Transend's updated cost information template indicated an FDC allowance of $3.6 million for 2007–08 down from $4.6 million in the draft decision.

15 AER, *Transend draft decision,*op.cit., pp. 56-57.

16 The CPI data is available from the Australian Bureau of Statistics.

to be commissioned in 2008–09. Therefore, the total amount of Transend's commissioned assets during the current regulatory period will be revised to $363 million ($nominal).

Transend has also provided an updated amount of $60 million (exclusive of FDC) for assets under construction in 2007–08.[17] The AER considers the amount of $55 million provides a better estimate of expenditure for assets under construction which would be incurred before the end of the current regulatory period.

To the extent that the actual values for commissioned assets and assets under construction differ from forecast values for the final year of the current regulatory control period, a reconciliation will be undertaken—at the time of the next revenue reset—using the actual values as part of the asset base roll forward process at the next revenue reset.[18]

Based on updated information provided by Transend and the assessment made in the draft decision the AER considers that the total amount of:

- $387 million in relation to commissioned assets during the current regulatory control period is prudent and should be included in Transend's RAB
- $55 million in relation to assets under construction at the end of the current regulatory control period is prudent and should be included in Transend's RAB.

Using the updated information provided by Transend, the AER has made consequential revisions to the FDC allowances because they are dependent on the amount, asset category and profile of capex to be included in the RAB.[19] Based on the methodology accepted by the AER in the draft decision, the AER considers that the updated capex values result in revised FDC allowances of:

- $24 million for Transend's commissioned assets[20]
- $1.9 million for Transend's assets under construction.[21]

Differences in the values presented by Transend and the AER are due to the application of the AER's real cost escalation factors which are discussed in chapter 4.

17 The draft decision adopted a forecast amount of $44 million for assets under construction in 2008–09.

18 As required under schedule 6A.2.1(f)(3), the reconciliation would include adjustments that remove any benefit or penalty on the returns associated with any difference between forecast and actual values.

19 The ACCC's 2003 revenue cap decision recognised Transend's capex on an as-commissioned basis. As such, the ACCC accepted it would be appropriate for capex to include an FDC allowance to provide for the efficient cost of financing projects when they are under construction but not earning revenues.

20 The draft decision accepted the application of an FDC factor of 7.54 per cent to determine the FDC allowance for Transend's commissioned assets. Transend's updated cost information template indicated an FDC allowance of $5.3 million for 2008–09.

21 The draft decision applied an FDC factor of 7.54 per cent to Transend's assets under construction. This final decision applies an FDC factor of 7.54 per cent.

2.5.3 Other issues

Submissions

The EUAA stated that that WorleyParsons' ex post review of Transend's capex was methodologically flawed and hence provided no reasonable basis for concluding that historic overspend was prudent and efficient.[22]

AER considerations

Detailed review of selected past capex projects

The ACCC's 2003 revenue cap decision for Transend provides that capex undertaken during the 2004–2008/09 regulatory control period will be subject to an ex post prudence review.

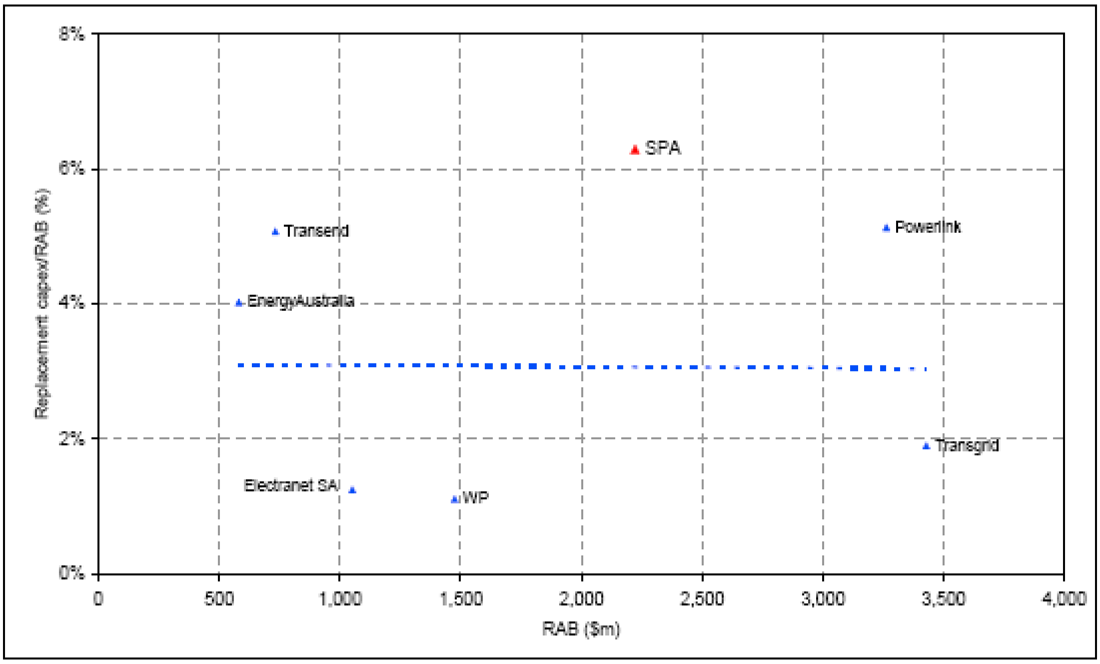
Further, the AER considered the capex benchmarks (shown at figures 2.1, 2.2 and 2.3 below) suggested that examination of Transend's renewal expenditure was warranted.

These benchmarks were prepared by PB in the course of its investigations assisting the AER's 2007 review of the SP AusNet revenue proposal. The capital expenditure is the average annual capital expenditure ($2007–08) during the most recent regulatory period in each jurisdiction and the information represented in the figures was sourced from the AER's TNSP regulatory report for 2005–06 and publicly available regulatory determinations.[23]

In figure 2.1, the measure for Transend is similar to Powerlink and lower than SP AusNet/VENCorp, but higher than other transmission networks. The AER considered the differences could be due to the age of networks, differences in materials and labour costs, differences in compliance and security requirements and substitution of replacement capex for opex. Transend appeared to have fairly high replacement costs as a proportion of its RAB. This is quite different from that of total capex as a function of network length (figure 2.2) and the total capex per GWh of transmitted energy (figure 2.3) is relatively high. These benchmarks were a consideration in the AER's decision to undertake a specific review of Transend's replacement capital expenditure activities in conjunction with its broader review of Transend's proposal.

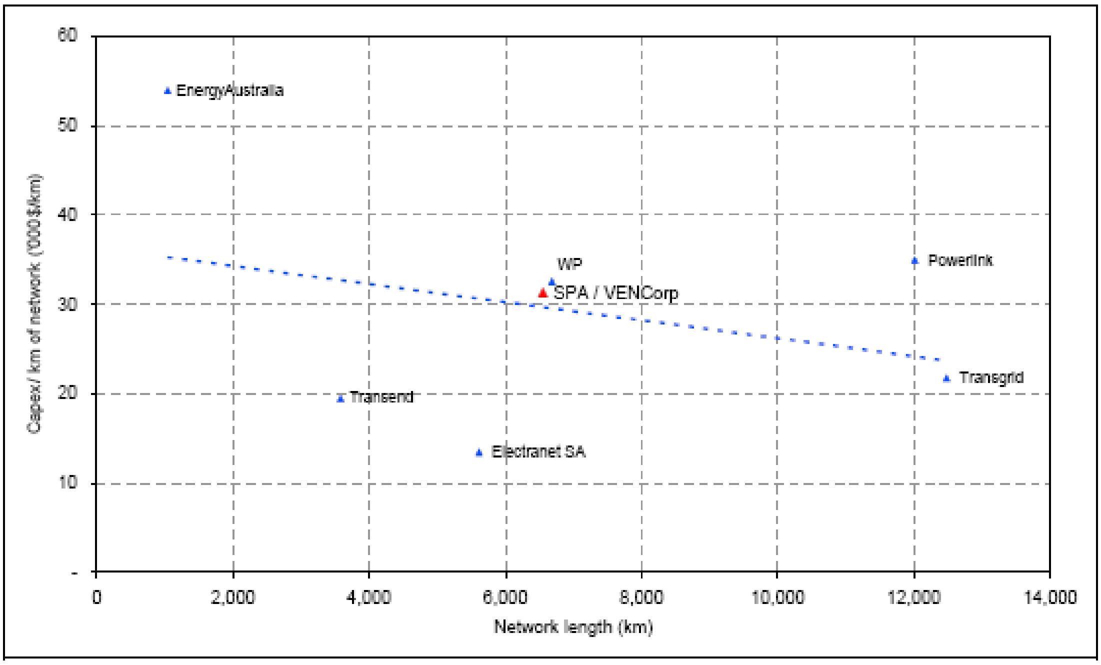
[22] EUAA, *Submission to AER on the draft decision.* op. cit. pp. 6-8.
[23] PB, *SP AusNet revenue reset: An independent review for AER*, 16 August 2007, pp. 46, 48-9.

Figure 2.1: Replacement capital expenditure as a proportion of RAB value



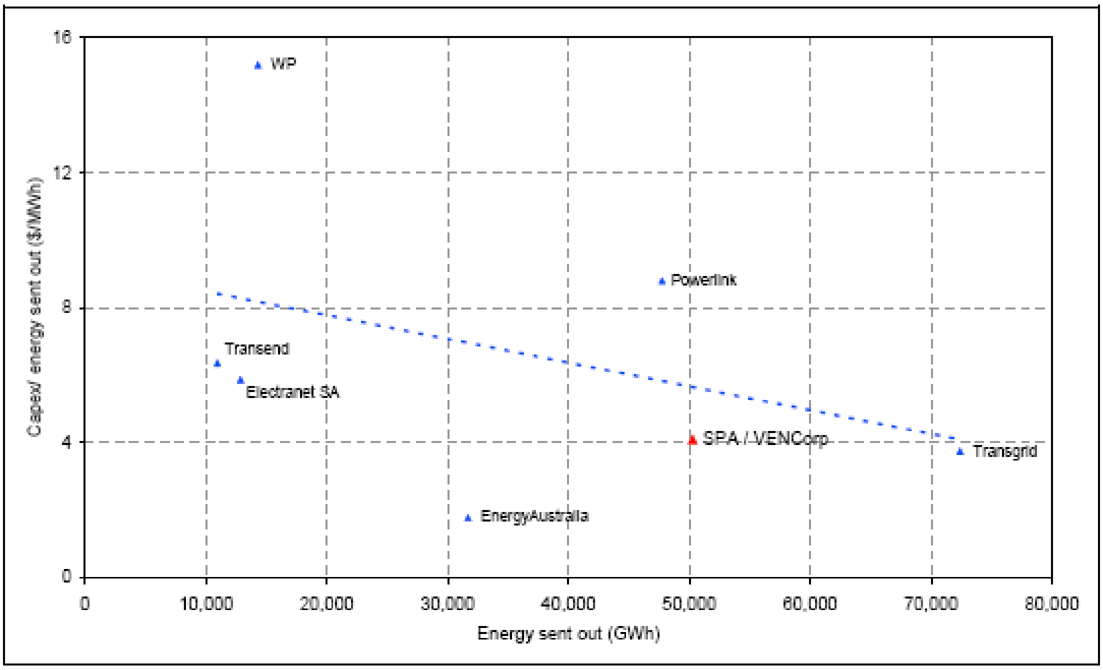
Source: PB analysis

Figure 2.2: Capital expenditure as a function of network length



Source: PB analysis

Figure 2.3: Capital expenditure per GWh of transmitted energy



Source: PB analysis

The AER's assessment of Transend's past capital expenditure was assisted by WorleyParsons and Nuttall Consulting. The AER engaged WorleyParsons to review Transend's capex, excluding asset renewal capex. Nuttall Consulting was separately engaged to review Transend's asset renewal capex in the current regulatory control period in view of the ACCC's 2003 revenue decision stating Transend should "demonstrate that its renewal expenditures are economically justified and that there are no, more cost effective, alternatives".[24]

WorleyParsons and Nuttall Consulting provided their opinion to the AER on the prudence and efficiency of the relevant elements of Transend's capex proposal based on their independent reviews. The AER considered this advice in its deliberations leading to the Transend draft decision.

The EUAA has suggested that WorleyParsons' detailed project review was methodologically flawed on the basis that a review of 10 out of Transend's 298 projects and programs in the current regulatory control period is not statistically significant and cannot provide the basis for conclusions on the population and that the sample may not be representative of the population.[25]

The AER considers the projects reviewed by WorleyParsons and Nuttall Consulting adequately represent the population and proportionally reflect the amount of capital expenditure in the current regulatory control period. The selection of projects was done in consultation with the AER and was designed to cover a broad range of projects across different asset classes, locations and timings. In total, projects equivalent to approximately 44 per cent of Transend's capex in the current regulatory

[24] ACCC, *Tasmanian transmission network revenue cap2004–2008/09: Decision,* 10 December 2003, p. 42.

[25] EUAA, *Submission to AER on the draft decision.* op. cit. p. 7-8.

control period have been comprehensively reviewed with WorleyParsons reviewing approximately 24 per cent (10 projects with a value of approximately $99 million) and Nuttall Consulting reviewing approximately 20 per cent (11 projects with a value of approximately $84 million). In conducting a review it is necessary for the AER to balance sample size against the substantially increased cost and time requirements that would accompany an exhaustive review. Although the examination of a greater number of projects may have improved the statistical factors it is by no means certain that such an examination would have resulted in any different outcome.

The EUAA has also stated that WorleyParsons should have compared what Transend told the AER that it would do at the previous revenue reset with what Transend actually did to determine the reasons for the significant overspend.[26]

The AER notes that, at WorleyParsons' and Nuttall Consulting's request, Transend developed a document to reconcile the projects identified at the time of the ACCC's 2003 decision with the projects which will be implemented during the current regulatory control period.[27] This document, together with other supporting information provided by Transend, was examined by the AER and considered by both WorleyParsons and Nuttall Consulting in their respective reviews.

In assessing the projects, the consultants considered the following matters:

- whether or not there was genuine need for the project
- whether Transend had considered the complete range of feasible alternatives
- whether the scope, cost and timing of the proposed project was efficient
- whether the project aligned with Transend's strategic plans, governance arrangements and capex policies and procedures.

In general, both consultants agreed with Transend's capex timing during the current regulatory control period. The AER directed its consultants to examine the observed difference in sequence to the original timing. As discussed in the following section a major issue identified was the delay in the Southern Augmentation project (which includes the Waddamana–Lindisfarne 220 kV transmission line project) leading Transend to bring forward other projects within the limitations of the available resources. Both consultants concluded that any alternative timing would not alter their overall conclusion that there was no evidence that Transend's expenditure was not justified and prudent.

Past capital expenditure spending profile

The AER notes that the total capex approved for the current regulatory control period was an allowance only and was not tied to a fixed, project-specific work program. This also applies to the forthcoming period and is a feature of the ex ante regime under chapter 6A of the NER. Within the approved allowance, Transend retained discretion regarding the allocation and expenditure of capital. The AER expected Transend to be responsive to changing conditions in order to meet customer and

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26 EUAA, *Submission to AER on the draft decision,* op. cit, p. 8.

27 Response to information requests Nos. 74, 76, 77 and 78, confidential, submitted 27 August 2008—Transend, *Capital expenditure profiles and variations for the period January 2004 to June 2014 TNM-GS-809-0864*, Issue 0.4, August 2008.

generator requirements as well as changing regulatory/technical requirements while managing and operating the network in accordance with good electricity industry practice. That Transend did reorder its capital project priorities in the face of the delay to the Waddamana-Lindisfarne project was to be expected in the circumstances.

As noted in the draft decision, cost escalators applied at the time of the ACCC's 2003 decision were lower than the actual escalation of costs observed during the current regulatory control period. The AER considers that Transend has gone some way to responding to (increasing) labour and other input costs beyond its control by implementing an improved cost estimating process and an integrated works planning tool. In particular, improvements in Transend's cost estimating processes and governance and business practices utilised in decision-making processes, were driven by feedback from specific project experiences. WorleyParsons' review confirmed that Transend's implementation of a works program integrating capex and opex activities and customer and operational requirements resulted in efficiency gains.[28] WorleyParsons also identified Transend's development of a dynamic rating system for its transmission lines as a cost-effective innovation, which allowed the transmission lines to carry additional loads for specified time periods, subject to environmental conditions, and thereby defer capex on building or replacing transmission lines.[29]

The AER and its consultants reviewed information provided by Transend in support of capex projects and capex spending profile in the current regulatory control period. The detailed project reviews assessed specific variations in project costs and scope from original estimates.[30] The AER notes that WorleyParsons stated that Transend considered a range of project options, including non-network solutions. WorleyParsons considered that the technical designs were consistent with good industry practice and there was no evidence of 'over-design'. Further, project costs were reasonable when compared with estimates prepared by WorleyParsons based on similar projects.[31]

The detailed project reviews informed the AER's investigation of the variations in the actual capital expenditure from that allowed in the ACCC's 2003 decision. In assessing Transend's past capex, the AER and its consultants have had regard to the information available to Transend at the time it made the decision to invest. In the case of Transend's largest capex project in the current regulatory control period (the Waddamana–Lindisfarne 220 kV transmission line and substation project), delays in receiving necessary regulatory approvals and planning permission contributed to delays in project commencement. The project commenced in December 2007 and is expected to be completed in December 2010. There have been consequential delays in other projects. Transend has stated that the Creek Road and Tungatinah substation

28 WorleyParsons, *Review of the Transend transmission network revenue proposal 2009-2014: An independent review prepared for the Australian Energy Regulator*, October 2008, p. 44.

29 ibid, p.224.

30 ibid, Appendix 3; Nuttall Consulting, *Review of Transend revenue proposal asset renewal capital expenditure: A report to the Australian Energy Regulator*, November 2008, p. 56.

31 WorleyParsons, *Review of the Transend transmission network revenue proposal 2009-2014: An independent review prepared for the Australian Energy Regulator*, October 2008, pp.63-64 and Appendix 3.

redevelopment projects have been delayed until the next regulatory control period because of access issues associated with the Waddamana–Lindisfarne 220 kV line.[32]

The AER also notes that Transend has developed its asset management regime over the current regulatory control period to focus on condition monitoring in addition to defect identification. The AER is satisfied that the increase in replacement capex during the current regulatory control period includes a catch-up component for expenditure that would have been addressed earlier under a more rigorous asset management regime.

The AER considers that project delays and deferrals, together with the more detailed asset condition information, influenced Transend's decision to commit to higher levels of replacement expenditure during the current regulatory control period. The AER notes the impact on maintenance expenditure arising from the replacement program is reflected in Transend's opex allowance. However, the reduction in maintenance opex was offset by the higher internal and external labour costs during the current regulatory control period and the costs of NEM entry which were greater than anticipated.[33]

In its draft decision, the AER concluded that Transend's expenditure of $415 million during the current regulatory control period was prudent and should be included in its RAB.[34] The AER confirms its draft decision that, even though Transend did not follow its forecast spending profile, as approved by the ACCC in its 2003 revenue cap decision, the explanations provided in Transend's proposal and additional supporting information were reasonable.

2.6 AER conclusion

Based on updated information provided by Transend and the assessment made in the draft decision the AER considers that the total amount of:

- $387 million in relation to commissioned assets during the current regulatory period is prudent and should be included in Transend's RAB
- $55 million in relation to assets under construction at the end of the current regulatory period is prudent and should be included in Transend's RAB.

Using the updated information provided by Transend, the AER has also made consequential revisions to the FDC allowances because they are dependent on the amount, asset category and profile of capex to be included in the RAB.[35] Based on the methodology accepted by the AER in the draft decision, the AER considers that the updated capex values result in revised FDC allowances of:

32 Transend, *Capital expenditure profiles and variations for the period January 2004 to June 2014 (Issue 0.4, August 2008),* submitted 27 August 2008.

33 Transend, *Revenue proposal,* op. cit., p. 45.

34 AER, *Transend draft decision,* op. cit, p. 56.

35 The ACCC's 2003 revenue cap decision recognised Transend's capex on an as-commissioned basis. As such, the ACCC accepted it would be appropriate for capex to include an FDC allowance to provide for the efficient cost of financing projects when they are under construction but not earning revenues.

- $24 million for Transend's commissioned assets for the current regulatory period[36]
- $1.9 million for Transend's assets under construction for the current regulatory period.

Differences in the values presented by Transend's revised proposal and the AER are due to the application of the AER's real cost escalation factors which are described at chapter 4 and appendix A.

Table 2.1 shows the capex spend for the current regulatory period.

Table 2.1: AER conclusion on past capex ($m, nominal)

	2004 (Jan to Jun)	2004–05	2005–06	2006–07	2007–08	2008–09	Total
Commissioned capex	27.9	49.5	63.7	91.0	56.0	74.4	363.1
Finance During Construction	2.0	2.8	4.0	5.8	3.6	5.3	23.5
Assets Under Construction	–	–	–	–	–	55.3	55.3

36 The draft decision accepted the application of an FDC factor of 7.54 per cent to determine the FDC allowance for Transend's commissioned assets. Transend's updated cost information template indicated an FDC allowance of $23.5 million for end of the current regulatory period.

3 Opening regulated asset base

3.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision on Transend's opening regulated asset base (RAB), including matters raised by Transend in its January 2009 revised revenue proposal (revised revenue proposal).

3.2 AER draft decision

The AER determined Transend's opening RAB to be $994 million for the next regulatory control period (as at 1 July 2009).[37] Chapter 3 of the draft decision sets out the roll forward methodology used by the AER to establish the opening RAB.

The AER noted in the draft decision that it would update the roll forward of Transend's RAB with actual capex for 2007-08, the most recent forecast of capital expenditure for 2008–09 and the latest consumer price index (CPI) data at the time of its final decision.[38]

3.3 Transend revised proposal

Transend has implemented all aspects of the AER draft decision. It has also included updated forecasts of commissioned assets and assets under construction in the current regulatory control period in establishing a revised proposal for the opening RAB. Transend's revised opening RAB for the next regulatory control period is $961 million.[39]

3.4 Issues and AER considerations

3.4.1 Asset base roll forward

AER draft decision

The AER rolled forward Transend's 2004 RAB and determined its opening RAB to be $994 million for the next regulatory control period (as at 1 July 2009).

AER considerations

Based on the updated values for commissioned assets and assets under construction, the AER's application of the roll forward methodology has determined that Transend's opening RAB is $951 million for the next regulatory control period (as at 1 July 2009).[40] This value is used as an input for the AER's post-tax revenue model for the purposes of determining Transend's maximum allowed revenue during the next regulatory control period.

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[37] AER, *Transend transmission determination for the regulatory control period 1 July 2009 to 30 June 2014: Draft decision*, 21 November 2008, p. 64-65.

[38] ibid., p. 64-65.

[39] Transend, *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 14 January 2009, p. 21.

[40] As noted in chapter 2 the difference between the AER and Transend's opening RAB is due to the real cost escalators applied.

3.4.2 Error in Disposal Values

AER draft decision

The AER accepted Transend's proposed disposals values from its revenue proposal.

AER considerations

Transend informed the AER, following discussion of its depreciation methodology outlined in section 9.5.3 of this final decision, that it had made an error in calculating its disposals for the RFM. The AER has reviewed the corrected inputs for disposals and accepts that they are appropriate for the purposes of the RFM.

This correction of the error in disposal values affects the values for prudent capex and the return on difference.

3.5 AER conclusion

Using the updated values for commissioned assets and assets under construction, the AER's application of the roll forward methodology has determined that Transend's opening RAB is $951 million for the next regulatory control period (as at 1 July 2009). The RAB roll forward calculations are set out in table 3.1.

Table 3.1: Transend's opening RAB for the next regulatory control period ($m, nominal)

	2004 (Jan to Jun)	2004–05	2005–06	2006–07	2007–08	2008–09[a]
Opening RAB	603.6	628.7	696.1	737.3	811.4	850.5
Forecast capex (adjusted for actual CPI)[b]	28.6	84.4	56.0	95.1	46.0	40.0
Straight-line depreciation (adjusted for actual CPI)	–3.5	–17.0	–14.8	–21.0	–6.9	–6.0
Closing RAB	628.7	696.1	737.3	811.4	850.5	884.5
Add: prudent capex over 2003 decision[c]						33.8
Add: return on difference[d]						–5.9
Add: prudent assets under construction						55.3
Opening RAB at 1 July 2009						951.4

(a) Updated with actual CPI for 2007–08 (March to March).
(b) 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.
(c) Includes the difference between actual and forecast capex for the $16.8 million underspend from 1 July to 31 December 2003 and a $50.6 million overspend from 1 January 2004 to 30 June 2009. The cash values for disposal of assets have been updated in this final decision due to an error and have been deducted.
(d) This relates to the return on difference between actual and forecast capex for the period 1 July 2003 to 31 December 2003.

4 Forecast capital expenditure

4.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision on Transend's forecast capital expenditure (capex), including matters raised by Transend in its January 2009 revised revenue proposal (revised proposal).

4.2 AER draft decision

In the draft decision the AER did not accept Transend's proposed ex ante capex allowance of $681 million ($2008–09) and explained the reasons why it was not satisfied the proposal reasonably reflected the capex criteria under clause 6A.6.7(c) of the NER.

The AER made the following adjustments to Transend's proposed ex ante capex allowance:

- adjustment resulting from WorleyParsons' review of capex (excluding renewal capex) of $4.8 million
- adjustment resulting from Nuttall Consulting's review of the renewal capex of $50.1 million
- adjustment resulting from application of AER annual escalators of $10.6 million.

The AER considered that an ex ante forecast capex allowance of $615 million represented the total capex that a prudent operator in the circumstances of Transend would require to achieve the capex objectives and would reasonably reflect the capex criteria. In addition, the AER approved an indicative contingent projects allowance of $412 million. Table 4.1 sets out the AER's ex ante capex allowance for Transend as in the draft decision.

Table 4.1: AER draft decision – Transend ex ante allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Transend proposal (31 May 2008)	158.0	173.4	106.5	118.5	124.3	680.7
Adjustment resulting from detailed project reviews [a]	–1.4	–5.0	–3.7	–19.7	–25.2	–55.0
Application of annual escalators	–2.0	–1.8	–1.6	–2.0	–3.1	–10.6
AER's total adjustments	–3.4	–6.8	–5.3	–21.8	–28.3	–65.6
AER's ex ante capex allowance	154.6	166.6	101.2	96.8	96.0	615.1

Source: AER, *Transend transmission determination 2008–09 to 2012–13: Draft decision*, 21 November 2008, pp. 143-144.

(a) These adjustments relate to augmentation, easement and replacement projects.

4.3 Transend revised proposal

Transend has implemented the AER draft decision in respect of forecast capex except those related to:

- renewal capex projects
- labour and non-labour cost escalation
- contingent projects.

Transend's revised forecast capex also took account of the most recent information relating to the Sheffield substation 220 kV power system security upgrade and substation physical security upgrade projects which are expected to be completed in 2009-10 rather than 2008-09 as proposed in Transend's May 2008 revenue proposal (original proposal).

Transend has also proposed moving the Waddamana–Lindisfarne 220 kV transmission line second circuit project from contingent project to ex ante capex. As a result, Transend's revised proposal includes 8 contingent projects. The total indicative cost for the 8 contingent projects is $390 million.

Transend's revised ex ante capex proposal of $711 million ($2008–09) is set out at tables 4.2 and 4.3. The network augmentation category in the revised ex ante capex proposal includes an amount for the Waddamana–Lindisfarne 220 kV transmission line second circuit project.

Table 4.2: Transend ex ante capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER's draft decision on Transend's ex ante capex allowance	154.6	166.6	101.2	96.8	96.0	615.1
Transend's revised proposal (14 January 2009)	181.8	187.6	105.7	116.9	118.7	710.8

Source: AER, *Transend transmission determination 2008–09 to 2012–13: Draft decision*, 21 November 2008, pp. 143-144.
Transend, *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 31 June 2014*, 14 January 2009, p. 41.

Table 4.3: Transend ex ante capex proposals ($m, 2008–09)

Category	Transend proposal (31 May 2008)	Transend revised proposal (14 January 2009)
Augmentation	227.6	253.8
Connection	121.8	123.2
Land and easements	20.9	21.6
Asset renewal	226.6	222.7
Physical security/compliance	10.7	20.0
Inventory/spares	11.7	11.8
Operational support systems	22.3	22.6
Total network	***641.6***	***675.8***
Information technology	21.3	17.0
Business support	17.8	18.0
Total non-network	***39.1***	***35.0***
Total ex ante capex	**680.7**	**710.8**

Source: Transend, *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 31 June 2014*, 14 January 2009, pp. 25, 41.
Note: Totals may not add up due to rounding.

4.4 Submissions

The AER received submissions commenting on the AER draft decision and Transend's revised proposal from the following interested parties: Mr David Asten, the Major Employers Group (MEG); the Energy Users Association of Australia (EUAA), Nyrstar, Powerlink and TransGrid.

The main issues raised in submissions were in relation to:

- the effect of the demand forecast on Transend's proposed capex for the next regulatory control period
- transfer of Waddamana–Lindisfarne second 220 kV second circuit project from contingent project to ex ante capex
- Transend's revised labour and non-labour cost escalators
- Transend's 110 kV substation redevelopment projects associated with replacement of Reyrolle OS10 circuit breakers
- the inclusion of distribution assets in Transend's asset base, that is, assets operating at voltages typically lower than 66 kV
- the cost estimation risk factor applied to the capex program

- the strategic acquisition of land and easements
- the consultants' review of the need for investment in the next regulatory control period.

4.5 Consultant review

The AER engaged Nuttall Consulting to review and critically assess the information provided by Transend to support its revised proposal. Nuttall Consulting's review focussed on the following issues:

- the new information on asset renewal capex
- transfer of the Waddamana–Lindisfarne second 220 kV second circuit project from contingent project to ex ante capex
- the need for the Sheffield–Burnie 110 kV transmission line augmentation project.

Based on the information provided by Transend in its revised proposal and in response to requests for additional information and clarification, Nuttall Consulting recommended that:[41]

- an amount above the allowance approved in the AER's draft decision was reasonable for asset renewable capex
- the Waddamana–Lindisfarne second 220 kV second circuit project should not be included in the ex ante capex. It should continue to be treated as a contingent project
- it will be prudent and efficient to undertake the Sheffield–Burnie 110 kV transmission line project as proposed.

Table 4.4 sets out the AER's draft decision on asset renewal capex, Transend's revised proposal and Nuttall Consulting's recommended ex ante asset renewal capex allowance for each regulatory year of the next regulatory control period.

Table 4.4: Asset renewal ex ante capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER's draft decision on Transend's ex ante capex allowance	28.1	34.0	21.7	42.8	44.6	171.2
Transend's revised proposal (14 January 2009)	29.5	41.0	23.6	61.9	66.7	222.7
Nuttall Consulting recommendation	29.2	38.8	22.5	53.1	56.2	199.8

Source: Transend CAM Model, 11 November 2008.
Transend, *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 31 June 2014*, 14 January 2009, p. 41.
Nuttall Consulting, *Review of the Transend revised revenue proposal: A report to the Australian Energy Regulator*, April 2009, p. 39.

41 Nuttall Consulting, *Review of the Transend revised revenue proposal: A report to the Australian Energy Regulator*, April 2009, pp.6-7.

4.6 Issues and AER considerations

4.6.1 Demand Forecast

AER draft decision

The AER accepted Transend's demand forecast methodology and Transend's demand forecast for the next regulatory control period.

The AER also considered the relevance of the demand forecast in respect of the proposed capex program noting that the forecast demand is a primary driver for only 23.2 per cent ($158.8 million) of all capital expenditure. A further breakdown of drivers showed that:

- $95.6 million (13.9 per cent of all capex) related to connection requests from Aurora Energy which Transend is required to address under clause 5.3.2(d) of the NER
- $49.2 million (9.2 per cent of all capex) is required because the forecast demand will lead to breach of the Tasmanian network performance requirements.
- $14 million (2.0 per cent of all capex) related to the Sheffield–Burnie 110 kV transmission line augmentation project (ND 0945), which is driven solely by Transend's forecast demand for the north-west region.

Transend revised proposal

Transend did not submit a revised demand forecast in its revised proposal.

Submissions

A number of submissions stated that Transend's demand forecast should be revisited to take into account the impact of the global financial crisis and the carbon prices forecast by the Carbon Pollution Reduction Scheme (CPRS) on Tasmanian electricity demand and the consequential effect on Transend's proposed capex program.[42]

AER considerations

At the predetermination conference held in Hobart on 10 December 2008, a number of stakeholders raised the issue of current economic circumstances and questioned Transend's capex proposal in light of the changes in economic conditions and the proposed introduction of a national emissions reduction scheme. The EUAA subsequently submitted that the AER should review the need for all significant capital projects and consider project deferral or re-classification as contingent projects.[43]

[42] Major Employers Group, *Major Employer Group (Tasmania) Submission to AER on the Transend transmission revised revenue proposal*, February 2009, p. 2

Nyrstar, *Submission to Transend's revised revenue proposal*, Confidential, February 2009, p. 3-4

EUAA, *Submission to AER on the draft decision on Transend's regulated revenue for the 2009 to 2014 regulatory period*, 13 February 2009, p. iv-v

[43] ibid, p. v

Transend is currently preparing its 2009 demand forecast which it anticipates will be available at end-April 2009.[44] The AER notes that, although Transend has made reference to forecast changes in Tasmanian demand having been considered by Aurora Energy, Transend's own preliminary 2009 demand forecasts for the southern and north-western regions do not indicate significant demand reductions in the next regulatory control period.[45] The AER notes that Transend has modelled the impact of the introduction of an emissions reduction scheme in its *Transend Networks: 30+ year network vision*.[46] However, release (on the 15 December 2008) of the Commonwealth Government's white paper setting out the likely policy for the CPRS, will require detailed modelling to establish its effect on Tasmanian demand.

The AER acknowledges that economic conditions have changed dramatically over the course of 2008 and could potentially impact the need for capital expenditure. For this reason, the AER has undertaken further specific investigation of the need for major projects in the connection and augmentation network capex categories and this is summarised below. These categories were selected for investigation because of the strong relationship they have with the demand forecast. The AER notes that Transend has not altered its proposed network capex program in anticipation of changes to its demand forecast.

Connection capex

In December 2008, the AER sought the views of Aurora Energy on whether the projects proposed by Transend to support Aurora Energy network connections remained likely to be required in the next regulatory control period. In response, Aurora Energy has confirmed to the AER that it works closely with Transend to maintain a continuous joint planning process and that all the proposed connection projects will be required to be delivered in the stated timeframes to meet Aurora Energy's reliability and security obligations.[47] The AER notes that, for each of the proposed connection projects, Aurora Energy has either submitted applications to connect to Transend's network or submitted connection enquiries to initiate the joint planning process.[48] The AER takes this as confirmation of the need for the connection projects. Further, the AER notes that Transend is required to prepare an 'offer to connect' in accordance with the requirements set out in clauses 5.3.5 and 5.3.6(d) of the NER on receipt of an application to connect to its network. The AER also notes that these projects are closely aligned to the residential sector and to an existing need to improve reliability in the distribution network.

44 AER–Nuttall Consulting–Transend meetings on 17-18 February 2009.

45 Transend, *Information request 302 per 27-30 January 2009: Sheffield –Burnie 110 kV transmission line,* 6 February 2009.

Transend, *Information request 344,* emails dated 13 March 2009 and 18 March 2009.

Transend, *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 14 January 2009, p. 31 and Appendix 11.

46 NOUS, *Transend Networks: 30+ year network vision project final report*, May 2007, p. 18

47 Transend, *Revised revenue proposal,* op. cit, p. 21.

48 Aurora Energy, *Re:Aurora Energy response to AER re:Transend proposed connection projects for 1 Jul-2009 to 30 Jun-2014*, email dated 18 March 2009.

Augmentation capex – Sheffield–Burnie 110 kV transmission line

Transend has noted that a contingency event will overload the Sheffield–Burnie 110 kV transmission lines when the connected loads exceed the capability of the lines. Subject to the availability of wind generation and the application of dynamic transmission line ratings, Transend may need to 'radialise' the network in order to be able to satisfy the requirements of clause 4.2.4 of the NER and return the system to a satisfactory operating state following a credible contingency event. The resulting radial network would put more than 25 MW at risk of interruption by a credible contingency event in breach of the *Tasmanian Electricity Supply Industry (Network Performance Requirements) Regulations 2007* (Tasmanian network performance requirements regulations).

Nuttall Consulting considered that Transend has not adequately demonstrated that non-compliance with the NER power system security obligations alone leads to a reasonable need for this project. However, Nuttall Consulting accepted that radialising the network may be required at times of high summer demand, in which case more than 25 MW of load might be shed following a credible contingency. In this regard, Nuttall Consulting found that Transend's 2009 preliminary load forecast suggests higher summer maximum demands in the Burnie area and therefore increased loading on the Sheffield–Burnie 110 kV transmission lines. Further, Nuttall Consulting noted that the level of wind generation from the Woolnorth wind farm and the application of dynamic line ratings would affect the likelihood of actual non-compliance with the Tasmanian network performance requirements regulations. However, Transend's analysis of these matters was not sufficient to allow Nuttall Consulting to determine the likelihood of non-compliance.

The AER considers that clause 5.2.3(f) of the NER requires Transend to comply with all relevant regulatory obligations, which include the Tasmanian Electricity Code and the Tasmanian network performance requirements regulations. The Office of the Tasmanian Economic Regulator administers Transend's licence for operating the Tasmanian electricity transmission network. The AER notes that, as a condition of this licence, Transend must comply with all relevant laws, rules, codes and guidelines, including the Tasmanian Electricity Code.[49] That is, Transend is required to plan and develop its network based on these requirements.[50] Further, section 14 of Transend's transmission licence requires it to plan and procure transmission system augmentations which satisfy the regulatory test.[51] In this regard, Transend has identified the need for the project in its 2008 Annual Planning Report and will undertake consultation on this project in accordance with clause 5.6.6A of the NER.[52]

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49 Office of the Tasmanian Economic Regulator, *Electricity supply industry transmission licence*, Effective Date 21 December 2008, clause 3.1.

50 *Tasmanian electricity supply industry (network performance requirements) regulations 2007*.
Tasmanian Electricity Code, as amended 1 January 2008. This document is available at http://www.energyregulator.tas.gov.au .

51 Office of the Tasmanian Economic Regulator, *Electricity supply industry transmission licence*, Effective Date 21 December 2008, section 14.

52 Transend, *Transend 2008 annual planning report*, version 0, p. 72. This document is available at www.transend.com.au.

At the AER's 6 August 2008 public forum presenting Transend's original revenue proposal submission, the presentation by the Tasmanian Office of Energy Planning and Conservation noted that Transend must plan its network so as to rectify identified breaches, however, there is no specified requirement for Transend to correct all existing identified breaches in the next regulatory control period. That is, the Tasmanian network performance requirements regulations state the minimum network performance requirements and do not specify a time period within which Transend is obligated to correct existing identified breaches.[53] In these circumstances, Transend is at risk of breaching the regulations if it does not adequately plan to meet this obligation.

Nuttall Consulting also noted that Transend has considered reasonable alternative options to solving the possible non-compliance with the Tasmanian network performance requirements regulations. These alternative options include the construction of the Sheffield–Burnie 220 kV new transmission line, use of the existing Burnie–Waratah 110 kV line, use of a special protection scheme, network support, as well as new generation and demand management options.[54]

The AER considers that implementation of the Sheffield–Burnie 110 kV transmission line augmentation project will remove network operational constraints which might otherwise result in Transend being in potential breach of the Tasmanian network performance requirements regulations. [55] If Transend is to ensure compliance with the broader requirement to maintain power system security as set out at clause 4.3.1 of the NER, the result may be non-compliance with Tasmanian jurisdictional requirements.[56] The AER considers that Transend has correctly applied the reliability requirements to its network and proposed projects that would allow it to meet the Tasmanian network performance requirements regulations.

Conclusion

The review of the Sheffield–Burnie 110 kV transmission line augmentation project confirmed that the demand forecast is not the primary driver of this project. Rather, the Tasmanian network performance requirements regulations are a major driver of this, and a number of other network augmentation projects in the ex ante capex allowance. Further, another major driver of the network capex requirement is Aurora Energy's connection requests. These are expenditures which the AER must allow under the regulatory test and the NER respectively. The AER considers that the proposed augmentation and connection projects should reman in the ex ante capex. The AER notes that Transend proposed that a number of projects where high-demand may result in a need for capex be placed in the contingent project category rather than

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53 AER, *Transend revenue proposal*. op. cit p. 91-92.

Tasmanian Government, *Electricity supply industry (network performance requirements) regulations 2007* is available at www.thelaw.tas.gov.au.

54 Nuttall Consulting, *Review of the transend revised revenue proposal: A report to the Australian Energy Regulator*, April 2009, p. 57.

55 *Tasmanian electricity supply industry (network performance requirements) regulations 2007*. clause 5(1)(a)(i).

56 Clause 4.3.1 of the NER discusses the responsibility of NEMMCO for power system security.

Nuttall Consulting, *Review of the Transend revised revenue proposal: A report to the Australian Energy Regulator*, April 2009, p. 54.

the ex ante category. The AER considers this is also likely to have reduced the sensitivity of the Transend capex allowance to changes in demand.

For the reasons discussed and as a result of the AER's analysis of the revised proposal, the AER is satisfied that Transend's proposed augmentation and connection capex reasonably reflects a realistic expectation of the demand forecast.

4.6.2 Transfer of Waddamana–Lindisfarne 220 kV transmission line second circuit contingent project to ex ante capex

AER draft decision

Table 4.5 sets out the AER's approved triggers and indicative cost for the approved Waddamana–Lindisfarne 220 kV transmission line second circuit contingent project.

Table 4.5: Waddamana–Lindisfarne 220 kV transmission line second circuit contingent project: AER approved project triggers and indicative cost ($m, 2008–09)

Project name	Project trigger	Indicative cost
Waddamana– Lindisfarne 220 kV transmission line second circuit	Demand forecast in Tasmania's southern area exceeding 880MW or Gordon power station not being able to provide reactive support when the southern area load exceeds 775MW and successful application of the regulatory test for augmentation of the transmission capacity into southern Tasmania	22

Source: AER, *Transend transmission determination 2008–09 to 2012–13: Draft decision*, 21 November 2008, pp. 136-137, 327-328.

Transend revised proposal

Transend stated new information had become available since the submission of its original proposal such that the Waddamana–Lindisfarne 220 kV transmission line second circuit project should no longer be a contingent project and should, instead, be included in the ex ante capex for the next regulatory control period. Transend considered that the forecast unavailability of the Gordon power station for an extended period in 2014 satisfied a trigger event approved by the AER. Further, Transend's analysis indicated that the project would provide a net market benefit.[57] In January 2009, Transend commenced a consultation in accordance with the requirements of the regulatory test – the last day for submissions was 10 February 2009.[58]

Submissions

The MEG submitted that the Waddamana–Lindisfarne 220 kV transmission line second circuit project is only triggered in the last year of the next regulatory control

57 Transend, *Revised revenue proposal*, op. cit, p. 40

58 Transend, *New small transmission network asset: Waddamana-Lindisfarne 220 kV transmission line second circuit public consultation paper TNM-GR-809-0926*, Issue 1.0, January 2009.

period and should be restored to the contingent project category because of the likelihood of lower growth than forecast.[59]

Consultant review

Nuttall Consulting reviewed the need and justification for the inclusion of the Waddamana–Lindisfarne 220 kV transmission line second circuit project in the ex ante capex. The review did not attempt to determine the appropriateness or otherwise of the Waddamana–Lindisfarne 220 kV transmission line first circuit project which is already included in the ex ante capex.

Nuttall Consulting also considered whether all reasonable alternatives to constructing the second circuit at the same time as the first circuit, had been considered in Transend's application of the regulatory test (and associated calculation of market benefits arising) from completing the project in the next regulatory control period.

Nuttall Consulting recommended that the project remain as a contingent project until Transend adequately demonstrates:[60]

- the planned outage of Gordon power station will most likely extend across the peak winter period in 2014; or
- the risks associated with the uncertainty in the outage timing are sufficient to justify the second circuit under the regulatory test, considering all reasonable alternatives, including:
  - reactive plant with full cognisance of Transend reactive plans independent of this need
  - the optimal timing the second circuit if undertaken after the first circuit
  - a *Tasmanian Electricity Supply Industry (Network Performance Requirements) Regulations 2007* compliant special protection scheme using involuntary load shedding, similar to the existing "southern system special protection scheme" (SSSPS) to mitigate risks due to timing variations
  - network support utilising a post-contingent special protection scheme, if feasible, to mitigate risks due to timing variations (i.e. based upon the SSSPS) and
  - combinations of the above.

Nuttall Consulting concluded by noting that Transend's preliminary 2009 demand forecast does not show a significant reduction in maximum demand up to the time of the proposed Gordon power station outage period and therefore does not affect the findings of the regulatory test completed by Transend for this project. Nuttall Consulting also concluded that the existing trigger as proposed by Transend is deficient in that it does not adequately distinguish between a generation outage event

59 Major Employers Group, *Major Employer Group (Tasmania) submission to AER on the Transend transmission revised revenue proposal*, February 2009, p. 3

60 Nuttall Consulting, *Review of the Transend revised revenue proposal: A report to the Australian Energy Regulator*, April 2009, pp. 49-50.

and potential breach of the Tasmanian network performance requirements regulations.[61]

AER considerations

The AER considers the approved contingent project triggers must be satisfied if the Waddamana–Lindisfarne 220 kV transmission line second circuit project is to be included in the ex ante capex. In the case of Transend's revised proposal, the relevant contingent project triggers are:

- Gordon power station not being able to provide reactive support when the southern area load exceeds 775 MW; and
- successful application of the regulatory test for augmentation of the transmission capacity into southern Tasmania.

Gordon power station outage

The AER has reviewed the project information provided by Transend and considers that the inability of Gordon power station to provide reactive power for a period of three to six months in the 2013–14 financial year is the key contingent project trigger driving the consideration of the transfer of the project to ex ante capex. The AER recognises that Transend is currently reliant on the Gordon power station for generation to meet the southern area demand and for the provision of reactive power when the southern area load exceeds certain MW 'trigger' levels.[62]

The AER notes that Hydro Tasmania has not set firm dates for the proposed outage. As a result, Transend has investigated the impact on its network operation of the proposed outage across an 18 month period ranging from October 2013 to March 2015.[63] The significance of the variation in estimated unserved energy for various outage durations across this period has been investigated by Nuttall Consulting.[64] The AER considers that the timing of the power station outage directly affects the selection and assessment of likely alternative sources of reactive support to manage the consequences (as approximated by the estimated unserved energy) of the proposed outage. The AER agrees with Nuttall Consulting's view that uncertainty in the timing of the power station outage imposes risks on Transend and its customers in considering alternatives to minimise expected unserved energy.[65]

The AER does not consider that the trigger event has occurred. Having reviewed the information provided by Transend regarding the timing of the proposed outage of the Gordon power station, the AER has not been able to establish and confirm the time period for the proposed Gordon power station outage.

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61 ibid., pp. 45-46.

62 Transend, *Contingent project investment report – Waddamana-Lindisfarne 220 kV second circuit TNM-PL-809-0722-035*, Issue:1.0, August 2008, p.3.

63 AER–Nuttall Consulting–Transend meetings on 17-18 February 2009.

64 Nuttall Consulting, *Review of the Transend revised revenue proposal*, op. cit, pp. 43-45.

65 ibid., p. 45.

Southern area load

Transend has provided historical actual load data which confirms that the southern area load exceeded 775 MW in 2008. [66] The AER considers this supports the likelihood of the southern area load exceeding 775 MW in the 2013–14 financial year under low demand growth scenarios. The AER also notes that Transend's preliminary 2009 demand forecast for the southern region forecasts minimal load reductions despite the current economic conditions. The AER accepts Nuttall Consulting's advice that this forecast should not significantly affect Transend's regulatory test findings.[67]

Further, although 775 MW is the specified load trigger level for the southern area load when Gordon power station is unavailable to provide reactive power, 743 MW is the actual operational trigger level at which the Gordon power station is required. This is because 743 MW is the effective southern area load limit used in the NEMMCO dispatch engine to determine when Gordon power station should be dispatched so that the NER voltage performance criteria (that is, voltage stability limits) are satisfied. For this reason, Transend has applied 743 MW as the load limit in calculating 'expected unserved energy'. Transend has advised that the 743 MW trigger value can be reconciled with the 775 MW trigger value specified in its southern area development plan on consideration of different assumptions used to derive the different values.[68] In assessing whether the southern area load exceeds 775 MW at a time when the Gordon power station is not able to provide reactive support, the AER will have regard to the methodology used by Transend to reconcile the 743 MW value with the 775 MW value.[69]

Application of the regulatory test

The AER considers Transend's revised proposal to include the project in the ex ante capex is, in effect, a 'scope change' of the Waddamana–Lindisfarne 220 kV transmission line and substation project which is already included in the ex ante capex. In its original proposal, Transend stated that, as part of the tender process for the Waddamana–Lindisfarne 220 kV transmission line, Transend was seeking prices for stringing the line with both single and double circuits.[70] Transend also stated:

> The choice to build either a straight or staged double-circuit line depends on the future level of demand growth relative to the cost differential of stringing one or two circuits. Actual market prices may indicate that there is a market benefit from initially stringing the line as a straight double circuit. [71]

Transend has advised that it is still negotiating actual market prices with preferred tenderers. It has also indicated that the revised proposal estimated project cost of $18.5 million ($2008–09) is in line with current actual market prices if the project is constructed at the same time as the first circuit, as proposed. The AER considers that

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66 Transend, *AER information request 341 per 2-6 March 2009,* email dated 4 March 2009.

67 Nuttall Consulting, *Review of the Transend revised revenue proposal*, op. cit, pp. 48-50.

68 Transend, *Information request 335 per 23-27 February 2009: Waddamana-Lindisfarne 2nd circuit project*, 25 February 2009, p. 1.

69 ibid., and email dated 29 March 2009.

70 Transend, *Contingent project investment report – Waddamana-Lindisfarne 220 kV second circuit TNM-PL-809-0722-035*, Issue 1.0, August 2008, p.4

71 ibid., p. 6.

the market benefit (calculated using actual market prices) from initially stringing the line as a straight double circuit must be shown to maximise the net economic benefit when compared with other likely alternative options.

The AER has reviewed Transend's application of the market benefits limb of the regulatory test (version 3) to the project together with the published consultation notice. The AER is not satisfied that Transend has adequately assessed all likely alternative options under reasonable scenarios as required under the market benefits limb of the regulatory test. Transend's consideration of alternative sources of reactive power such as capacitor banks and static var compensators is also not apparent and the impact of implementation of the Waddamana–Lindisfarne 220 kV transmission line on the network operational requirement for additional sources of reactive power beyond the 2013–14 financial year is not clear.[72]

The AER acknowledges the importance of the Gordon power station in providing reactive support to maintain voltage stability and security of supply to Hobart. The AER considers the actual timing of the power station outage is critical to determining the need for construction of the straight double circuit transmission line. The AER notes that Transend's project analysis has focussed on the maximum possible length of the outage across the winter period which coincides with the southern area maximum demand period. Given the Gordon power station may be unavailable for between three to six months in 2013–14, the AER considers that by focussing on the longer period Transend's analysis may overstate the possible unserved energy relating to this outage.[73]

The AER also notes Nuttall Consulting reports that his investigations have revealed a possibility that the project may already be required under the reliability limb of the regulatory test. But Nuttall Consulting also cautions that the regulatory test analysis undertaken to date is incomplete in that it is focussed on the market benefits limb of the regulatory test. Nuttall Consulting concludes that further investigation is required.[74]. The AER notes that based on the Nuttall Consulting advice the proposed trigger event is incomplete in that it does not properly account for this eventuality.

Conclusion

The AER agrees with Transend that it would be inefficient from a project management perspective to re-enter and disturb properties to string the second circuit within a relatively short timeframe after constructing the line with one circuit. Transend's revised proposal sought to move this project from the contingent project category to the ex ante cap on the basis that it was sufficiently likely that the trigger event would occur in the near future and that it would be efficient to bring this project forward. However, the AER considers that Transend has not adequately demonstrated the need for the construction of the Waddamana–Lindisfarne 220 kV transmission line as a straight double circuit line at this time. The AER is not satisfied that

72 Nuttall Consulting, *Review of the Transend revised revenue proposal*, op. cit, pp. 46-49; Transend, *re:Phone message at 12:31*, email dated 29 March 2009; Transend, *Capital project investment report: Waddamana-Lindisfarne 220 kV transmission line: second circuit document reference D08/10198*, 13 January 2009.

73 ibid, pp. 43-45.

74 ibid, pp. 45-46.

sufficient certainty currently surrounds the likelihood of, or the timing or duration of, an outage of the Gordon Power Station to warrant approving this project now.

In forming this view the AER notes that the regulatory test undertaken to date has focussed solely on the market benefits limb of the regulatory test. That analysis demonstrates that under some scenarios the project is justified but the AER is not satisfied that this conclusion is true for a sufficient range of scenarios to warrant approving the project now. The AER also notes Nuttall Consulting's conclusion that an expanded regulatory test assessment may demonstrate a requirement for this project in the next regulatory period on reliability grounds in accordance with the Tasmanian network performance regulations. The AER's assessment has identified a number of scenarios which indicate this project is likely to satisfy the regulatory test and expects that under a more comprehensive analysis it is likely this project would proceed. The AER accepts Nuttall Consulting's advice that the trigger event for this project is inadequately specified and should be amended to allow consideration under either limb of the regulatory test. This is discussed further in section 4.6.6.

For the reasons discussed and as a result of the AER's analysis of the revised proposal, the AER is not satisfied that the transfer of the Waddamana–Lindisfarne 220 kV transmission line second circuit project from contingent project to the ex ante capex reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

4.6.3 Renewal Capex

AER draft decision

The AER did not accept Transend's forecast asset renewal capex allowance as proposed. The AER reviewed the economic analyses that Transend provided to Nuttall Consulting. The AER noted that Transend had adopted a least cost approach to its economic analysis and had not attempted to quantify all economic costs and benefits associated with its investment decisions.

The AER approved an allowance of $176.5 million—a reduction of $50.1 million ($2008–09) from that which Transend proposed—for asset renewal capex.

The draft decision stated that although the adjustments made by the AER for the most part were set out on a project specific basis, the total capex after all of these adjustments is only an allowance. The AER's project specific conclusions do not bind Transend to a particular set of project specific capex budgets—Transend has the ultimate discretion on how it allocates its capex allowance.[75]

Transend revised proposal

110 kV substation redevelopment projects associated with replacement of Reyrolle OS10 circuit breakers

Transend undertook additional analysis (including a pre-investment risk review) providing a more comprehensive assessment of deferral options for the projects. The analysis considered optimal scoping and timing for the replacement of all circuit

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75 AER, *Transend draft decision*,op.cit. p.143.

elements for bays that contain Reyrolle OS10 circuit breakers. Transend's analysis confirmed the appropriateness of the original planned replacement program.

Transend incorrectly stated that the AER's draft decision applied a 60 per cent reduction to the proposed allowance for the proposed Temco 110 kV substation redevelopment project. The AER's draft decision applied a 40 per cent reduction to the amount in Transend's original proposal.

Farrell and New Norfolk substation secondary system replacement projects

Transend undertook additional analysis including risk assessments to examine different project staging options. Transend concluded that some capital expenditure could be deferred while noting the deferred amount was less than recommended by Nuttall Consulting.

Burnie–Waratah 110 kV transmission line wood pole replacement project

Transend corrected the timing of the project costs to 2010-11 and 2013-14, consistent with its three-year inspection cycle. Transend considered that its forecast replacement of 30 structures in 2010-11 and 40 structures in 2013-14 is supported by a longer-term time series analysis of pole replacements for this line. Transend also stated that its practice is to replace condemned poles within 3 months of the inspection and that inspections are programmed such that condemned structures can be replaced prior to winter in the year of the inspection.

Submissions

TransGrid and Powerlink have submitted that the replacement of the Reyrolle OS10 circuit breakers is appropriate based on their own experiences of defect and condition issues leading to replacement of Reyrolle OS10 circuit breakers within their respective networks.[76]

Consultant review

Nuttall Consulting reviewed the information provided by Transend in support of its proposed reinstatement of amounts for asset renewal capex. It considered that Transend had not adequately demonstrated that the asset renewal expenditure in the revised proposal was the prudent and efficient amount required to meet the capex objectives set out in Chapter 6A of the NER. It also considered that further analysis would identify other project efficiencies.[77]

Nuttall Consulting's recommended ex ante capex allowance for asset renewal capex for each regulatory year of the next regulatory control period is set out at table 4.6 below. Nuttall Consulting stressed the importance of considering the recommended adjustments in the context of Transend's overall asset renewal capex requirements.

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76 TransGrid, *Submission in relation to the AER's draft decision for Transend and Transend's revised revenue proposal*, 18 February 2009, p. 1-2

Powerlink, *Draft decision Transend transmission determination 2009-10 to 2013-14*, 18 February 2009, p. 1

77 Nuttall Consulting, *Review of the Transend revised revenue proposal*, op. cit. p. 39.

Table 4.6: Nuttall Consulting's recommended forecast asset renewal ex ante capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Transend's revised proposal (14 January 2009)	29.5	41.0	23.6	61.9	66.7	222.7
Adjustment to 110 kV substation redevelopment projects	-	– 0.3	– 1.1	– 8.6	– 8.2	– 18.3
Adjustment to Farrell and New Norfolk secondary system replacement projects	– 0.3	– 1.0	-	– 0.2	– 0.7	– 2.2
Adjustments to Burnie–Waratah 110 kV transmission line wood pole replacement project	-	– 0.8	-	-	– 1.7	– 2.5
Nuttall Consulting recommendation	29.2	38.8	22.5	53.1	56.2	199.8

Source: Nuttall Consulting, *Review of the Transend revised revenue proposal: A report to the Australian Energy Regulator*, March 2009, p. 39.

AER considerations

The objective of the AER's assessment of specific proposed projects is to test the efficiency and prudence of Transend's policies, procedures, replacement strategies and cost estimates as they relate to the entire forecast capex proposal. The AER considers these to be relevant considerations in determining whether it is satisfied Transend's total forecast capex proposal reasonably reflects the capex criteria.

The AER did not consider that the information provided by Transend at Appendix 5 of its revised proposal presented a clear case for the proposed reinstatement of allowances for:

- 110 kV substation redevelopment projects associated with replacement of Reyrolle OS10 circuit breakers
- Farrell and New Norfolk substation secondary system replacement projects
- Burnie–Waratah 110 kV transmission line wood pole replacement project.

Further information was requested from Transend by the AER and Nuttall Consulting in relation to supporting Transend's proposed reinstatement of renewal capex amounts. Further clarification was also sought to identify the new information and resolve inconsistencies in the information provided by Transend to the AER.

In responding to the further questions by the AER and Nuttall Consulting, Transend drew attention to the failure of a Reyrolle circuit breaker at the Creek Road substation which was found in January 2009 during routine maintenance. Transend considered this event highlighted increased safety risks relating to potential explosive failure of the circuit breaker and evidenced the need for urgent replacement of the Reyrolle circuit breakers.[78] This potential for explosive failure was explained as providing an additional driver for the need and timing of the relevant 110 kV redevelopment works.

The AER notes that Transend had previously identified management of safety risks (associated with plant/equipment clearances) as a key driver of the Tungatinah substation redevelopment.[79] The AER, however, does not consider that Transend's circuit breaker asset management plan highlights safety risks relating to circuit breaker failure as being a key driver for the proposed timing of the asset renewal/replacement. The AER considers that the significance of these safety risks became apparent to Transend subsequent to the Creek Road circuit breaker failure in January 2009.

The AER has considered the work undertaken by Transend to address specific asset renewal capex matters identified in the AER's draft decision and the Nuttall Consulting report. It has also reviewed the investment evaluation summaries, economic analysis and other additional information provided by Transend in support of its revised proposal to reinstate amounts relating to asset renewal capex. The AER's consideration of the specific asset renewal/replacement projects discussed by Transend in its revised proposal is set out below.

110 kV substation redevelopment projects associated with replacement of Reyrolle OS10 circuit breakers

The AER acknowledges the comments made by TransGrid and Powerlink regarding the replacement of Reyrolle OS10 circuit breakers in their respective networks. The AER notes that Nuttall Consulting's review concluded that the operational issues associated with Reyrolle and Sprecher and Schuh 110 kV circuit breakers were reasonable and warranted consideration in relation to their replacement.[80]

While Transend's 110 kV circuit breaker strategies are in line with those of other TNSPs, the significant number of replacements proposed for the next regulatory control period would significantly reduce the average age of the circuit breakers by the end of the next regulatory control period.[81]As stated in the draft decision, the AER considers that the significant decrease in the age profile of Transend's 110 kV circuit breakers suggests that the 110 kV circuit breaker replacement plans are overly aggressive.[82]

Economic analysis of projects

Transend's proposed expenditure profile for the 110 kV redevelopment projects associated with Reyrolle OS10 circuit breakers is concentrated in the last two years of

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78 Transend, *Information request 339 per 2-7 March 2009: Asset renewals*, 2 March 2009.

79 Transend, *Investment evaluation summary: Tungatinah substation 110 kV redevelopment TNM-GS-809-0720*, Issue 1.0, April 2008.

80 Nuttall Consulting, *Review of the Transend revised revenue proposal*, op.cit., pp. 38-39.

81 Transend, *Transend revised revenue proposal*, op.cit., Appendix 5, pp. 10-11; Nuttall Consulting, *Review of transend revenue proposal asset renewal capital expenditure: A report to the Australian Energy Regulator*, November 2008, pp. 20-21.

82 AER, *Transend draft decision,* op.cit. p. 102.

the next regulatory control period.[83] The AER's assessment of the economic analysis of the 110 kV substation redevelopment projects was informed by Transend's discussion of its risk review and project NPV analyses and Nuttall Consulting's assessment of these matters.

In support of its revised proposal, Transend has stated:[84]

- the issues associated with poor performing assets are real and present significant safety risks
- the issues associated with poor performing assets have a major impact on the reliability and security of electricity supply
- Transend's substation redevelopment program has targeted replacement of these poorly performing assets to address the identified issues and improve transmission system performance.

Transend accepted that its original economic analysis did not consider partial deferral or gradual replacement over an extended period of time.[85] It further developed its NPV analyses to consider these options. Transend also undertook a risk review to inform its assessment of risk costs assumed in the economic analysis of the projects.

The AER considers Transend's pre-investment risk review of its 110 kV substation redevelopment projects does not present an objective assessment of the risks presented by each of the assets included in the 110 kV substation redevelopment projects. The risk review is not a formal risk assessment conducted in accordance with the requirement of an industry standard or some other accepted standard such as AS/NZS 4360:2004.[86] Despite this, the AER accepts Nuttall Consulting's view that Transend's risk analysis has merit in the asset management process and in the quantification of risks associated with the 110 kV substation redevelopments.[87]

The AER notes that Transend's risk review has considered the criticality of the 110 kV circuits containing Reyrolle OS10 circuit breakers to support the need and proposed timing of the 110 kV substation redevelopment projects.[88] In this regard, Nuttall Consulting's review indicates that replacement of Reyrolle circuit breakers in high criticality circuits may not result in significantly reduced (reliability) risk costs.[89] The AER considers that the criticality of the circuits does not reflect the operational and market consequences of circuit failure.

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83 Transend, *AER request for information 295, 296 and 297 per 27-30 January 2009*, email dated 29 January 2009; Transend, *Transend Revised Revenue Proposal*, op.cit, Appendix 2 – Forecast capex.

84 Transend, *110 kV Substation Redevelopment Projects: Additional information supporting Transend's revised revenue proposal*, email to AER, 29 January 2009, slide 17.

85 Transend, *Transend Revised Revenue*, op.cit, Appendix 5, p. 7.

86 Nuttall Consulting, *Review of the Transend Revised Revenue*, op.cit., p. 16.

87 ibid. p. 17.

88 Transend, *Pre-investment risk review – 110 kV substation redevelopment projects TNM-CR-809-0923*, Issue 0.2, December2008, pp. 6,10-11.

89 Nuttall Consulting, *Review of the Transend revised revenue proposal*, op.cit pp. 28, 30.

It appears that catastrophic failure of the circuit breaker forms the basis of the risks assessed by Transend. Transend's risk review focussed on reliability risk costs.[90] The revised NPV analyses suggest there may be significant unmodelled risk costs which, together with the reliability risk costs, are greater than the avoided capital costs.[91] As a result, the AER considers that the revised NPV analyses have not accounted for, and quantified, all relevant risks, such as the recently identified increased safety risks.

In this regard, the AER considers that the inputs to and the outputs from the risk review were not critically evaluated to assess their validity. The AER also notes that Transend has made assessments using 'engineering judgement' which has not been well documented and, therefore, its application is not clear and transparent. The AER considers that corporate knowledge, per se, does not lend itself to an objective review of the prudent and efficient delivery of projects because the consequences and likelihood of occurrences are developed without any evidence of independently verified past experiences.

The AER considers the relationship between likelihood and consequence of risks is better expressed by Nuttall Consulting's risk contours.[92] The AER considers this approach better explains the relative risks associated with Transend's circuit breaker bays and provides an indication of the level of risks which are acceptable to and able to be managed by Transend.[93]

The AER considers that Transend's risk review does not adequately account for Transend's ability to mitigate the identified safety risks relating to equipment/plant failure. The review considered only circuits containing Reyrolle 110 kV circuit breakers. In response to questions raised by Nuttall Consulting, the review was extended to provide some comparison with risks relating to non-Reyrolle OS10 circuits. The risk review also did not provide comparison of the risks posed by 110 kV substation redevelopment project risks relative to the risks posed by other projects in the proposed asset renewal capex program.

Further, it appears that actual project timing is driven by coordination and prioritisation of projects within the overall works program.[94] For example, the timing of the Creek Road and Tungatinah 110 kV substation redevelopment projects remain subject to completion of work on the Waddamana–Lindisfarne 220 kV transmission line.[95] Transend has stated that any changes to individual project timing will be managed with consideration of the ex ante capital expenditure allowance.[96]

The AER accepts there is a need to replace poor performing assets for safety reasons. However, notwithstanding their relatively poor condition, the AER is not satisfied on

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90 ibid, pp. 18, 28.

91 ibid., pp. 27-30.

92 ibid., pp. 21-22.

93 ibid., pp. 19-22.

94 Transend, *Transend transmission revised revenue*, op.cit, Appendix 5, p. 11 and various Investment Evaluation Summaries.

95 ibid, Appendix 5, p. 4 , *Investment evaluation summary Creek Road substation 110 kV redevelopment TNM-GS-809-0720, Investment evaluation summary Tungatinah Substation 110 kV redevelopment TNM-GS-809-0720*.

96 Transend, *Information request 339 per 3-7 March 2009: Asset renewals*, 2 March 2009, p. 1.

the balance of the information provided by Transend that it would be prudent or efficient to replace all of theses assets during the next regulatory control period.

The AER notes that Nuttall Consulting maintains that Transend's economic analysis does not fully support the timing of the projects or the selection of the preferred option.[97] The AER accepts Nuttall Consulting's advice that there is a reasonable possibility of some deferral of works following further detailed project analysis in accordance with Transend's governance procedures.[98] The AER accepts Nuttall Consulting's recommendation of a 20 per cent reduction to the allowance sought by Transend in its revised proposal for the 110 kV substation redevelopment projects. This is still an increase on the amount allowed in the AER's draft decision for these projects.

Farrell and New Norfolk substation secondary system replacement projects

In additional information provided to the AER, Transend states that the assets are approaching the end of their expected lives and Transend is expecting an increased failure rate (with associated consequences) and total relay failure. It also stated:

> … [Transend is] operating these schemes in line with a 'run to failure' strategy which is counter to [Transend's] operational policies for protection schemes. … Transend cannot operate critical [bus bar and transmission line] protection schemes with a 'run to failure' philosophy which is counter to [Transend's] operational policies for protection schemes and good industry practice.[99]

The AER considers that Transend should operate its plant and equipment in line with good industry practice and that 'a run to failure' approach is not appropriate for critical circuits. But this approach does not inform a decision as to the most appropriate timing for the replacement of this equipment. The AER notes that Transend has calculated the risk costs associated with a major failure of the Farrell substation and New Norfolk substation protection schemes respectively on the basis of a 50 per cent probability of failure in 2009.[100] The AER agrees with Nuttall Consulting that Transend has not fully justified the substantial increase in failure rates used in the NPV analysis.[101] The AER expects that Transend would calculate the relevant risk costs assuming realistic failure rates/probabilities. The AER considers that a more thorough analysis of the impact of limited availability of spares and end-of-life equipment failure rates would be required to firmly establish an economic justification for upfront replacement of the Farrell substation secondary protection system.

The AER notes that, despite concerns relating to the validity of Transend's revised economic analysis and the additional information provided in support of the proposed projects, Nuttall Consulting considered there is a case for replacement of protection schemes at Farrell and New Norfolk substations. The AER accepts Nuttall

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97 Nuttall Consulting, *Review of the Transend revised revenue proposal*, op.cit, p. 27.

98 ibid., p. 31; Transend, *Investment evaluation of network projects TNM-GU-809-0056*, Issue 1.0, June 2008.

99 Transend, *Information request 334 per 23-27 February 2009: Asset renewals – protection replacement program*, 25 February 2009, p. 2-3.

100 ibid., p. 2-3.

101 Nuttall Consulting, *Review of the Transend revised revenue proposal*, op.cit, p. 33.

Consulting's advice that, although there is a case for replacement of protection schemes at Farrell and New Norfolk substations, there is a reasonable possibility of some deferral of works.[102] The AER accepts Nuttall Consulting's recommendation of a 15 per cent reduction to the allowance sought by Transend in its revised proposal for the Farrell and New Norfolk substation secondary system replacement projects. This will be an increase on the amount allowed in the AER's draft decision for these projects.

Burnie–Waratah 110 kV transmission line wood pole replacement project

The AER has reviewed the information provided by Transend in support of the Burnie–Waratah 110 kV transmission line wood pole replacement project in the revised revenue proposal. The AER accepts Transend's correction to the timing of the pole inspections to align with its stated policy to conduct 3-yearly inspection/testing cycles.

Transend provided data on the replacement history of the wood poles on the line for the 1991 to 2008 period. Using this information, Transend estimates that 10 wood poles will require replacement annually. In 2006, Transend adopted Aurora Energy's policies and procedures in relation to inspection/testing and maintenance of wood poles.[103] Further, Transend has estimated the pole failure rate for the Burnie–Waratah wood pole line by extrapolating the historical failure rate of the line using the forward estimated failure rate provided by HEC/Aurora Energy.[104] The AER agrees that some poles are likely to fail and require replacement in the next regulatory control period. However, it is not apparent that the failure rate of Aurora Energy's population of 250,000 poles located across Tasmania can be directly applied to establish the failure rate of the wood poles on the Burnie–Waratah wood pole line.[105]

The AER notes Transend's advice that the criteria, testing procedures and methodology for condemning wood poles have remained consistent since 1991.[106] Therefore, the AER considers that greater weight should be placed on the results of recent pole inspections than on the longer pole replacement history. This is on the basis that the recent inspections should better reflect the current condition of the poles on the line. Further, the actual condition of the poles (derived from pole inspection data) should form the basis of the estimated future pole replacement rather than the pole replacement volumes that have occurred across the asset replacement cycle.

In discussing the need for the project with the AER and Nuttall Consulting, Transend highlighted the bushfire and safety risks associated with wood poles in remote terrain. The AER accepts Nuttall Consulting's advice that, in reality. Transend must replace the poles that are condemned in line with its stated practices and procedures.[107]

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102 ibid., p. 35.

103 Transend, *Revised revenue proposal: Response to AER request – 298 Appendix 5 - Burnie-Waratah wood pole replacement project (TNM-GR-809-0929)*, Issue 0.2, February 2009, p. 4.

104 Transend, *Burnie-Waratah 110 kV transmission line wood poles condition assessment report (TNM-CR-808-0888)*, Issue 1.0, November 2008, p. 6.

105 Transend, *Revised revenue proposal* op. cit. p. 4.

106 Transend, *Burnie –Waratah 110 kV transmission line wood poles condition assessment report TNM-CR-808-0888*, Issue 1.0, November 2008, p.6.

107 Nuttall Consulting, *Review of the Transend revised revenue*, op.cit. p. 38.

The AER also accepts Nuttall Consulting's advice that 20 structures are likely to be replaced following the 2010–11 and in 2013–14 line inspections respectively.[108] The AER accepts Nuttall Consulting's recommendation that the amount proposed for 2010–11 should be reduced by one third and a 50 per cent reduction should be made to the amount proposed for 2013–14. The total reduction amounts to $2.5 million ($2008–09) reduction to the allowance sought by Transend in its revised proposal for the Burnie–Waratah 110 kV transmission line wood pole replacement project. This will be an increase on the amount allowed in the AER's draft decision for this project.

Conclusion

Given that no other significant reductions have been made to Transend's original proposal, the AER agrees with Nuttall Consulting that Transend's ability to manage its overall risks should be considered within the constraints of the total approved capital and operating expenditure allowances. In this regard, the AER notes that although Transend has prepared its forecast capex proposal on a detailed project-by-project basis, and the AER has for the most part assessed expenditure in this way, the AER's conclusions relate to a total forecast capex allowance.

Within the approved allowance, Transend retains discretion regarding the allocation and expenditure of capital. The AER expects Transend to be responsive to changing conditions in order to meet customer and generator requirements as well as changing regulatory, safety and technical requirements while managing and operating the network in accordance with good electricity industry practice. If any matter arises which requires Transend to reorder its priorities then it is appropriate for Transend to do so.

For the reasons discussed and as a result of the AER's analysis of the revised proposal, the AER is not satisfied that Transend's asset renewal capex as set out in its revised proposal reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

4.6.4 Input cost escalators

In line with recent AER decisions the AER allowed a set of labour and non-labour cost escalators for input cost prices. However, in conducting its analysis of the escalators the AER came to the conclusion that updated escalation factors should be required given the volatile economic conditions that prevail at the time.

The AER rejected the use of indirect cost escalation (that is escalation for producer's margins and producer's labour costs) and only allows escalation for direct TNSP costs.

The methodology and issues raised for labour and non-labour escalators are detailed in appendix A of this final decision.

AER draft decision

In assessing the escalators recommended by CEG and used by Transend, the AER considered that its conclusions from the recent 2008 ElectraNet decision were still applicable with respect to the methodology used for estimating each of these cost

[108] ibid., p. 38.

escalators (i.e. copper, aluminium and crude oil). In most cases, the AER considered that CEG had not presented any new compelling evidence that justified a departure from the approach previously accepted by the AER.[109]

At a fundamental level, the AER was concerned with the additional cost factors – producer margins, producer labour costs – that did not meet the underlying objectives for inclusion in forecast costs under clause 6A.6.7(c) of the NER.[110] As set out in appendix A, these costs represent a movement beyond the AER's obligation to provide a reasonable opportunity to recover efficient costs and are not necessarily consistent with the incentive framework. Also these cost escalators are not supported by robust data.

In particular, the AER considered that given the inherent uncertainties around the existence and estimation of real movements in these cost factors, it is unclear departures from CPI are warranted. The AER also noted that it accepted that such costs were likely to be included in base (unit) cost estimates but questioned the extent to which real growth was expected and whether it could be forecast on a reasonable basis.[111]

The AER also noted in the draft decision that it would update its escalators closer to the time of the release of its final decision and determination.[112]

Revised revenue proposal

Transend did not accept the materials cost escalators applied by the AER in the draft decision. Transend re-engaged CEG[113] to review the AER's draft decision and based on that advice, determined that while the AER's approach was largely reasonable, some of the technical aspects of the AER's modelling, principally in relation to timing, were cause for concern.[114] These concerns are outlined in more detail in appendix A.

CEG also raised issues associated with the update to the Econtech labour cost growth forecasts after the business has lodged its revised proposals. CEG stated that in the case of wage forecasts there is a degree of judgement involved in assessing the variables that make up labour cost forecasts. CEG stated that if the AER was to seek an update from Econtech for electricity, gas and water (EGW) wages and general labour cost growth rates this would be described as re-doing a forecast, rather than updating a forecast in accordance with an agreed methodology. CEG stated that the AER should consult with the businesses if further updates were proposed by Econtech.[115]

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109 AER, *Transend draft decision*, op.cit p. 357.

110 ibid., p.357.

111 ibid., p.357.

112 ibid., p.357.

113 CEG, *Escalations affecting expenditure forecast: A report for NSW and Tasmanian electricity businesses*, January 2009.

114 ibid., p.2.

115 ibid., p.13.

Transend requested an additional 2.1 per cent on top of the EBA base rate of 4.9 per cent for the current regulatory period as this represented the amounts paid in performance payments and employee increments to staff.[116]

Submissions

The EUAA stated that its NSW submission contained a critique relevant to Transend.[117] The issues raised in the EUAA's NSW submission are as follows:

- The EUAA noted the AER's explanation why a more detailed cost accumulation process was originally developed and welcomed the AER's decision to review input costs prior to the final decision.[118]
- The EUAA noted that due to the worsening economic climate, wage cost pressures had fallen. Further the EUAA noted:[119]
  - the RBA had revised its Wage Price Index from 4 per cent in 2008–09 to 3.5 per cent in 2009–10
  - the RBA expects the Wage Price Index to remain static at 4 per cent for 2010–11 to 2011–12.
- The EUAA also considered that the AER should make a robust assessment of the revised opex expenditures would ensure it was cost effective and efficient.[120]

AER considerations

The AER considers that a number of the improvements suggested by CEG and accepted by Transend to improve its approach to cost escalations are reasonable. The AER has updated its approach to reflect a number of these amendments as well as to account for the most recent data and to correct identified errors.

In terms of base metals and oil escalators, the AER agrees with Transend's revised revenue proposal that adopting a 12 month averaging period for materials escalators for each financial year of the next regulatory control period is reasonable. It considers this removes potential price distortions as it recognises that all objects are not costed and purchased over a single month but over each financial year of the period.

The AER notes Transend's revised proposal accepts the AER's rejection of lags on material cost escalators component of its forecast equipment purchase costs.[121]

The AER acknowledges Transend's concerns regarding the sole reliance on one economic forecaster for its labour growth and construction cost forecasts. In the draft decision, the AER did not consider the averaging methodology adopted by CEG was appropriate because the Macromonitor and Econtech EGW labour cost growth forecasts were not comparable and averaging the two forecasts was likely to produce

116 Transend, *Transend revised revenue proposal*, op.cit. p. 33.

117 Energy Users Association of Australia (EUAA), *Submission to AER on the draft decision on Transend's regulated revenue for the 2009 to 2014 regulatory period*, 13 February 2009, p. 6.

118 ibid, p.13.

119 ibid, p.18.

120 ibid, p.18.

121 Transend, *Transend revised revenue proposal*, op.cit. p. 34

unreliable labour cost escalation forecasts.[122] For this final decision, the AER maintains its view that it is not satisfied that Macromonitor provide sufficient explanation surrounding the basis of the model used to derive its forecasts. The AER also notes that Econtech found that upon reviewing CEG's revised escalator report, that it remained difficult to assess the forecast results provided by Macromonitor as no new information pertaining to the methodology have been provided.[123] The AER is satisfied that Econtech's methodology for forecasting labour costs growth is robust given the application of both an economic-wide model and a purpose-built labour cost model.[124]

The AER does agree with Transend regarding the need to address potential double counting of inflation when indexing between EBA and Econtech wage rates. The AER has therefore amended its approach to reduce the scope for double counting. Issues associated with labour escalators are also explored in chapter 6 and appendix A of this final decision.

For the same reasons as discussed for EGW, the AER considers that reliance on one economic forecaster to determine the construction cost escalator is also appropriate.

The AER notes Transend's revised revenue proposal removes real cost escalation from the proposed producer's margin and indirect producer's labour component of its forecast equipment purchase costs.

More detailed information on the AER's final assessment is detailed in appendix A of this final decision. Table 4.7 sets out the AER's conclusions on Transend's real escalators over the next regulatory control period.

Table 4.7 AER's conclusion on Transend's real escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–8.5	–17.3	–14.1	9.1	10.5	10.9	9.3
Copper	–4.3	–27.9	–10.8	2.1	2.5	2.3	2.0
Steel	12.1	16.3	–15.3	7.2	5.2	1.0	0.8
Crude Oil	31.2	–18.3	–5.2	10.2	5.7	2.2	1.3
EGW wages	0.3	1.1	2.7	2.7	1.3	0.6	–0.3
General wages	–2.2	–1.9	0.0	0.5	–0.7	–1.0	–1.5
Construction costs	1.4	–1.3	–1.6	1.0	0.6	–0.4	–2.2
CPI – June to June	4.5	1.8	2.8	2.0	2.5	2.5	2.5

122 AER, *Transend draft decision*, op.cit. p.361-362.
123 Econtech, *Updated labour cost growth forecasts*, March 2009, p. 21.
124 Econtech, *Labour Cost Growth Forecasts 2007/08 to 2016/17*.

Mapping Weights to Escalators

AER draft decision

The AER adjusted the mapping of the weights to reflect the draft decision on escalators by moving producer's labour and producer's margin weightings to CPI. The effect of this is that the weightings proposed by Transend have been mapped to a new 'General Other' category which is escalated by CPI.

Table 4.8 details Transend's weightings of escalators for the draft decision.

Table 4.8: AER Draft Decision – Capex estimate types map to input component costs (per cent)

	Aluminium	Copper	Crude oil	Fabricated steel	General labour	Producers' margin	Construction costs	TAS EGW Labour	Land & Easements	Land & Easements	Land & Easements	CPI
Aluminium	100											
Steel				100								
Copper		100										
Concrete (foundation)			20				80					
Buildings & Demolition							100					
General Other [a]												100
Transport			100									
Material - others [b]												100
Plant Hire & Establishment							100					
Labour-External - Civil & General							100					
Labour- External - EGW								100				
Labour - Internal								100				
Labour - Other					100							
Land (NW)									100			
Land (N)										100		
Land (S)											100	
Non-Network												100

Source: AER, *Transend transmission determination 2008–09 to 2012–13: Draft decision*, 21 November 2008, pp. 128-129.

Note:

(a) Producers' margin and Producers' labour have been rejected by the AER. Transend's proposed weightings against these categories have been re-assigned to a new 'General Other' category which is escalated by CPI.

(b) Transend proposed mapping 80 per cent of Material–others to Producers' labour and the remaining 20 per cent was mapped to Crude Oil for transport. The AER has mapped 100 per cent of Material-others to CPI.

Transend revised proposal

Transend accepted the mapping of weights as shown in table 4.8.

AER considerations

The AER draft decision contained an error that was inconsistent with other determinations by the AER. That is, it allowed for the escalation of transportation costs using the proxy of oil. This is inconsistent with other decisions released by the AER which only allow for oil to be used as an escalator for oil insulators in equipment such as transmission cables and transformers.

This has meant that the 20 per cent of concrete foundations has been reassigned from oil to construction costs, so that this component is now escalated by 100 per cent to construction costs. The other component that has changed is Transport which was formerly escalated 100 per cent by oil as a proxy for fuel which is now escalated by CPI.

The AER has discussed changing the escalator mapping for concrete (foundations) and transport as can be seen in table 4.9.

Table 4.9: AER conclusion – Capex estimate types map to input component costs (per cent)

	Aluminium	Copper	Crude oil	Fabricated steel	General labour	Producers' margin	Construction costs	TAS EGW Labour	Land & Easements	Land & Easements	Land & Easements	CPI
Aluminium	100											
Steel				100								
Copper		100										
Concrete (foundation)							100					
Buildings & Demolition							100					
General Other [a]												100
Transport												100
Material - others [b]												100
Plant Hire & Establishment							100					
Labour-External - Civil & General							100					
Labour- External - EGW								100				
Labour - Internal								100				
Labour - Other					100							
Land (NW)									100			
Land (N)										100		
Land (S)											100	
Non-Network												100

Source: AER, *Transend transmission determination 2008–09 to 2012–13: Draft decision*, 21 November 2008, pp. 128-129. As modified by AER.

Note:

(a) Producers' margin and Producers' labour have been rejected by the AER. Transend's proposed weightings against these categories have been re-assigned to a new 'General Other' category which is escalated by CPI.

(b) Transend proposed mapping 80 per cent of Material–others to Producers' labour and the remaining 20 per cent was mapped to Crude Oil for transport. The AER has mapped 100 per cent of Material-others to CPI.

Transend was consulted by the AER on the solution to the error in the AER's draft decision. The AER concludes that this change in the weightings has resulted in a $0.3 million increase in Transend capex for the next regulatory period.

Conclusion

For the reasons discussed and as a result of the AER's analysis of the revised proposal, the AER is not satisfied that Transend's revised mapping of weights for cost escalators reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

4.6.5 Allocation of assets to prescribed services

Submissions

MEG submitted that the AER should review the boundaries of the prescribed services taking into account the large influence of hydro and wind generation and Basslink on the operation and configuration of Transend's assets.[125]

Rio Tinto Alcan (RTA) was concerned that the AER, in the draft decision, had approved forecast capex and contingent projects that will be undertaken to provide negotiated transmission services.[126] Further, RTA submitted that transitional clause 11.6.11 of the NER does not affect the status of Transend's proposed contingent projects.[127] The contingent projects in question are:

- Sheffield-George Town new transmission line
- Burnie-Smithton new transmission line
- Sheffield-Farrell new transmission line
- Sheffield-Burnie new transmission line
- Palmerston-Sheffield 220kV transmission line augmentation[128]

RTA also considered that the draft decision suggested that the AER relied on Transend to inform the AER on whether part of its forecast capex may not relate to prescribed services, or may relate to prescribed service only because of clause 11.6.11 of the NER.[129]

AER considerations

The AER considers that the issue raised by the MEG is a complex matter that cannot be addressed in this determination. The Tasmanian transmission system has evolved over a substantial period of time and under vastly different governance and operational imperatives, especially prior to Tasmania's entry into the national electricity market.

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125 Major Employers Group, *Major Employer Group (Tasmania) submission to AER on the Transend transmission revised revenue proposal*, February 2009, p. 2

126 RTA, *Transend revenue cap 2009/10-2013/14: submission by Rio Tinto Alcan (Bell Bay) in response to the draft decision of the AER*, February 2009, pp.3-7

127 ibid., pp.7-11.

128 ibid., pp.1-2.

129 ibid., p.7.

Transend's transmission licence describes the Transend transmission network as extending "from the connection points for the Generation Sites and Transmission Sites listed … to the connection points for the Demand Sites and Transmission Sites listed". As a result, the Transend network, unlike its peers, is defined to include assets that operate at 6.6 kV, 11 kV, 22 kV, 33 kV, 44 kV, 110 kV and 220 kV. Therefore, the AER concluded in its draft decision that sub-transmission assets are properly included in the Transend asset base.[130] Further, the AER considers that the assets connecting Hydro Tasmania's plant to Transend's network are currently grandfathered as being prescribed services under NER clause 11.6.11 of the NER.

Under chapter 6A of the NER, Transend is only entitled to an allowance for future capital expenditure in relation to assets providing prescribed services. Chapter 6A of the NER currently provides a specific framework for negotiated transmission services. These services are provided outside of the regulated or prescribed services of a business. Allied to this, clause 11.6.11 describes the arrangements for the grandfathering of existing customer connections. In the Transend draft determination, the AER noted that the proposed redevelopment of certain substations as proposed by Transend may, under the then current clause 11.6.11, result in some assets no longer being eligible for inclusion in the Transend capital expenditure allowance, as they may cease to supply prescribed services if assets providing connection services are replaced.

Since the release of the AER's draft decision, the AEMC has released the National Electricity Amendment (Cost allocation arrangements for transmission services) Rule, effective on 13 February 2009. Among other things, this rule affects the way in which clause 11.6.11 operates.[131]

In the draft decision the AER stated that it expected the then forthcoming amendments to clause 11.6.11 would apply to Transend in relation to the treatment of replacement of assets that currently provide connection services under the NER. However, the AER has revisited this issue and no longer considers the amended clause 11.6.11 applies for the purposes of Transend's 2009-14 regulatory control period. To this end the AER notes section 33(1)(b) of Schedule 2 of the National Electricity Law ("NEL") provides that:

- The repeal, amendment or expiry of a provision of this Law, the Regulations or the Rules does not:

  …

  (b) affect the previous operation of the provision or anything suffered, done or begun under the provision;

The AER considers that the meaning of this provision is that a rule change cannot affect anything 'suffered, done or begun' under the rule before the rule change took effect. This means that anything done or suffered under clause 11.6.11 is not affected by the amendment, and anything begun while the old clause 11.6.11 was in force is not affected by the rule change. The submission of Transend's revenue proposal, the

130 AER, *Transend draft decision,* op.cit, p.260 and Appendix B.

131 AEMC, *Rule determination national electricity amendment (cost allocation arrangements for transmission services) rule 2009*, dated 29 January 2009, p.17.

making of submissions by stakeholders, and the release of the AER's draft decision, are all things 'suffered, done or begun' under the previous clause 11.6.11. The AER considers that a revenue determination process as a whole begins when the TNSP submits its revenue proposal and ends when the AER makes its final decision, and notes that neither the AER nor the TNSP has complete freedom to depart from what is in that original revenue proposal. Transend submitted its revenue proposal prior to the new rule taking effect and therefore the previous clause 11.6.11 should apply.

During the rule change process, the AEMC considered the issue of allowing a reopening of a revenue determination in respect of current processes underway to incorporate relevant assets for determinations made before the new clause 11.6.11 took effect. The AEMC decided against allowing a reopening, noting:

> On one interpretation of the NEL, a Rule change may not apply to existing processes. The proposed reopening of processes already underway may not be within the Rule making powers of the Commission.[132]

The AEMC cited section 33(1) of schedule 2 of the NEL to support this interpretation. It appears that the AEMC had reservations about applying the rule change to existing processes.

The AER considers that the application of section 33(1)(b) of schedule 2 of the NEL means that the amendment of clause 11.6.11 of the NER will have no effect on Transend's current revenue determination process because the process began when the unamended clause was in place and both Transend and the AER have 'done' certain things under the unamended clause.

Thus, the reset process began when Transend submitted its original proposal (31 May 2008), so the NER as it existed at that time continues to apply throughout the process.

Having regard to RTA's concerns, the AER wholly agrees with RTA that the AER cannot approve capex or contingent projects that relate to negotiated transmission services. Such approvals would not comply, respectively, with clauses 6A.6.7 and 6A.8.1 of the NER.

However, the AER disagrees with RTA's assessment that the contingent projects proposed by Transend relate to negotiated transmission services. The AER has reviewed the earlier work of WorleyParsons who examined each project in some detail and were satisfied that each project related only to prescribed transmission services. The AER also re-examined the project investment documentation for each contingent project and compared this to Transend's Tasmania Transmission System Diagram. It is clear from this examination that the proposed augmentations to the Tasmanian transmission network, in each case, are between two centres within the regulated network providing prescribed services, not negotiated services.

RTA is also concerned that the projects will be required as a result of connection applications by generators.[133] The AER does not agree with this view. The connection of the generator to the Transend network at an agreed connection point is a negotiated service and will be charged accordingly. Were Transend to augment its

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132 AEMC, *Rule determination: National electricity amendment (cost allocation arrangements for transmission services,) rule 2009*, 29 January 2009, p. 54.

133 RTA, *Transend revenue cap submission,* op cit, p. 6.

network so as to give these generators better connection to the transmission backbone without regard to whether there is a justified need for additional prescribed services the RTA position would be vindicated. But a generator connecting at a weak transmission connection point has no right to expect that the prescribed network will be automatically enhanced to accommodate the new capacity. Under the NER augmentation of the network can only occur under certain circumstances subject either to the application of the regulatory test or as a funded augmentation. The contingent project investment report for each project clearly specifies that the trigger of a pool of generation in the north-western and western areas of Tasmania is antecedent to successful application of a regulatory test. This test relates solely to the provision of prescribed services. Thus, the projects can only proceed if there is a net market benefit or if a reliability issue emerges that necessitates the upgrade of the regulated network. For each project, should an excess of generation become available at a nominated point in the network, Transend will study whether augmenting the network is the least cost option of meeting an emerging demand need or reliability criteria (as appropriate). If neither criterion is met or if a different option emerges as the best solution the contingent project will not proceed.

Transend considers that should the mooted investment in renewable energy proceed it will need to consider this circumstance and examine if the proposed augmentations pass the requisite regulatory test. Transend acknowledges that there is uncertainty about the generation trigger events occurring and the scope and cost of the projects; hence the application for the projects to be treated as contingent for the forthcoming regulatory control period.[134] The AER notes that the phrasing of the trigger events proposed by Transend for each project can be read to infer that the purpose of the contingent project is to provide an augmentation to improve generator access. This was not an intended outcome but does highlight that the phrasing of these triggers should be made clearer. Accordingly, the AER will recast the trigger to emphasise that each contingent project relates solely to prescribed services and that the contingent project must provide benefits to customers for the project to proceed.

RTA was also concerned that the AER was acting solely on the advice provided by Transend in relation to proposed forecast capex and contingent projects.[135] Transend's forecast capex and contingent projects have been subject to independent review by the AER, as well as WorleyParsons and Nuttall Consulting. The AER investigated projects undertaken by Transend in the period commencing 9 February 2006 when clause 11.6.11 commenced operation. No assets providing connection services were identified in the current regulatory period that would be affected by this provision. In the next regulatory period the Tungatinah substation redevelopment has been identified as a project that, were it to proceed, would have been affected by clause 11.6.11. As the draft decision did apply a reduction to the capital for that project no separate adjustment was made in accordance with clause 11.6.11. As the final decision will reinstate a capital allowance for this redevelopment, an adjustment is now necessary. As no firm design exists for the redevelopment of the substation the AER has estimated that in the 2009-2014 regulatory control period two generator connection bays will be required at an estimated cost of $0.6 million ($2008–09).[136]

134 Transend, *Revenue proposal*, Appendix 18, pp. 3,5,6,7,11.

135 RTA, *Transend revenue cap submission*, op. cit. p. 7.

136 Transend, *AER information request 350: AER (draft) final decision – Transend comments*, email dated 15 April 2009.

The AER will deduct this amount from the total ex-ante capex allowance. Consistent with the AEMC's Rule determination however, the AER notes that any expenditure by Transend in the next regulatory period will be eligible for consideration for inclusion in the regulated asset base at the next regulatory determination.

In relation to the application of clause 11.6.11 to Transend's contingent projects, for the same reasons discussed above, the AER agrees with RTA that clause 11.6.11 will have no effect.[137] The AER further notes that any new generator connections that have been developed after 9 February 2006 can never benefit from clause 11.6.11, as such connections are clearly negotiated.

Conclusion

For the reasons discussed and as a result of the AER's analysis of the revised proposal, the AER is not satisfied that Transend's allocation of assets to prescribed services reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

4.6.6 Contingent projects

AER draft decision

The AER approved 9 contingent projects for Transend with a total indicative cost of $412 million. Table 4.10 sets out the AER's approved triggers and indicative costs for the approved contingent projects.

Table 4.10: AER approved contingent projects, project triggers and indicative costs ($m, 2008–09)

Project name	Project trigger	Indicative cost
Sheffield–George Town new transmission line	Committed and/or advanced generation in the north-western and/or western regions in excess of 50MW and successful application of the regulatory test	70
Burnie–Smithton new transmission line	Committed and/or advanced generation projects in the north-western region in excess of 50MW and successful application of the regulatory test	88
Sheffield–Farrell new transmission line	At least 50MW of committed and/or advanced generation projects in the west coast area and successful application of the regulatory test	79
Sheffield–Burnie new transmission line	Demand in Tasmania's north-western region exceeding 360MW and/or in excess of 50MW committed and/or advanced generation projects in the north-western region and successful application of the regulatory test	52
St Helens new 110/22 kV connection site	Demand forecast in the east coast region exceeding 55MW and successful application of the regulatory test	46

137 ibid., p.11.

Palmerston– Sheffield 220 kV transmission line augmentation	At least 50MW of actual, committed and/or advanced generation projects in the north-western and/or western regions and successful application of the regulatory test	22
Waddamana–Lindisfarne 220 kV transmission line second circuit	Demand forecast in Tasmania's southern area exceeding 880MW or Gordon power station not being able to provide reactive support when the southern area load exceeds 775MW and successful application of the regulatory test for augmentation of the transmission capacity into southern Tasmania	22
Trevallyn Substation new 220/110 kV injection point	Demand in Tasmania's northern area exceeding 320MW and is forecast to exceed 355MW within 3 years and successful application of the regulatory test	21
Queenstown Substation security upgrade	Transend is unable to negotiate non-network solutions that enable it to meet the minimum network performance requirements for the Queenstown and Newton load and successful application of the regulatory test	11
Total indicative cost		**412**

Source: AER, *Transend transmission determination 2008–09 to 2012–13: Draft decision*, 21 November 2008, pp. 136-137, 325-328.

Transend revised proposal

Transend noted that the Waddamana–Lindisfarne 220 kV transmission line second circuit project had been approved by the AER as a contingent project in its draft decision. Transend then stated that new information on the forecast unavailability of the Gordon power station for an extended period in 2014 satisfied a trigger event approved by the AER. Further, Transend's analysis indicated that the project would provide a net market benefit. Therefore, Transend considered that this project should not be a contingent project and, instead, should be included in the ex ante capex for the next regulatory control period.

Submissions

The MEG submitted that the Waddamana–Lindisfarne 220 kV transmission line second circuit project is only triggered in the last year of the next regulatory control period and should be restored to the contingent project category because of the likelihood of lower growth than forecast.[138]

AER considerations

The AER's consideration of Transend's proposal to transfer the Waddamana–Lindisfarne 220 kV transmission line second circuit project to ex ante capex is provided at section 4.6.2 above.

138 Major Employers Group, *Major Employer Group (Tasmania) submission to AER on the Transend transmission revised revenue proposal*, February 2009, p. 3

The AER does not consider that the approved trigger events for the Waddamana–Lindisfarne 220 kV transmission line second circuit project have occurred. The project will remain as a contingent project.

The AER notes RTA's concern that the contingent projects may be inappropriately applied to the provision of negotiated services. As set out above, this should not occur but the wording "successful application of the regulatory test" repeated throughout the contingent project triggers do not make clear the distinction to the casual reader.

In its draft decision, the AER considered the matters in clause 6A.8.1(c) of the NER in determining the triggers for the contingent projects.[139] Following RTA's submission, the AER has re-examined the trigger events. The AER considers that the trigger events satisfy the matters in clause 6A.8.1(c) other than clause 6A.8.1(c)(1). To address this concern the trigger events have been restated to make clear that each project only relates to prescribed services and will only be approved if the specified trigger is achieved.

The AER also notes Nuttall Consulting's advice that the proposed trigger for the Waddamana–Lindisfarne contingent project does not distinguish between an outage driven need for the second circuit and a compliance driven need.[140] Under the Tasmanian network performance requirements regulations, the reliability criteria may be triggered by a number of conditions set out at section 5(1)(a). Under contingency events, greater than 300 GWh of unserved energy may eventuate at demand levels below the 775 MW nominated in the previous draft of the trigger. For the avoidance of doubt, the AER considers that 'a reliability driven need' in the description of the project trigger includes compliance with section 5(1)(a) of the Tasmanian network performance requirements regulations. The revised triggers have been set after consultation with Transend and Nuttall Consulting. Table 4.11 sets out the AER's approved triggers and indicative costs for the approved contingent projects. Appendix B provides a summary of all the contingent projects approved by the AER and describes the specific triggers and indicative costs for these projects.

Table 4.11: AER conclusion – approved contingent projects, project triggers and indicative costs ($m, 2008–09)

Project name	Project trigger	Indicative cost
Sheffield–George Town new transmission line	Application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in northern-western and/or western Tasmania when there is committed and/or advanced generation projects in the north-western and/or western regions in excess of 50MW.	70
Burnie–Smithton new transmission line	Application of the regulatory test demonstrates this option maximises the net economic benefit	88

139 AER, *Transend draft decision*, op.cit, pp. 133-137 and Appendix E.

140 Nuttall Consulting, *Review of the Transend revised revenue proposal*, op.cit, pp. 45-46.

	for the provision of prescribed services or a this option minimises the costs of meeting reliability driven need in northern-western and/or western Tasmania when there is committed and/or advanced generation projects in the north-western region in excess of 50MW.	
Sheffield–Farrell new transmission line	Application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in western Tasmania when there is committed and/or advanced generation projects in the west coast area in excess of 50MW.	79
Sheffield–Burnie new transmission line	Demand in Tasmania's north-western region exceeding 360MW and application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in northern-western and/or western Tasmania when there is committed and/or advanced generation projects in the north-western region in excess of 50MW.	52
St Helens new 110/22 kV connection site	Demand forecast in the east coast region exceeding 55MW and application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in the St Helen's region.	46
Palmerston– Sheffield 220 kV transmission line augmentation	Application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in northern-western and/or western Tasmania when there is committed and/or advanced generation projects in the north-western and/or western regions in excess of 50MW.	22
Waddamana–Lindisfarne 220 kV transmission line second circuit	Application of the regulatory test demonstrates: (i) this option maximises the net economic benefit for the provision of prescribed services when demand in Tasmania's southern area is forecast to exceed 880MW or Gordon power station is not able to provide reactive support when the southern area load exceeds 775MW; or (ii) the reliability limb is satisfied when a Transend planning study demonstrates a need under the Tasmanian *Electricity Supply Industry (Network Performance Requirements) Regulations 2007* for the construction of the second circuit in the next regulatory control	22

	period and this option minimises the costs of meeting those requirements.	
Trevallyn Substation new 220/110 kV injection point	Demand in Tasmania's northern area exceeding 320MW and is forecast to exceed 355MW within 3 years and application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in the Trevallyn region.	21
Queenstown Substation security upgrade	Transend is unable to negotiate non-network solutions that enable it to meet the minimum network performance requirements for the Queenstown and Newton load and application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in the Queenstown region.	11
Total indicative cost		**412**

Conclusion

For the reasons discussed and as a result of the AER's analysis of the revised proposal, the AER is not satisfied that the contingent project triggers reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

4.6.7 Other issues

Submissions

Mr David Asten submitted that it was inappropriate to include distribution assets in Transend's asset base.[141]

The EUAA submitted that it is inappropriate to apply cost estimation risk factor adjustments.[142]

The EUAA also submitted there was no compelling argument on strategic grounds to buy land for the Sheffield–Burnie new 220 kV transmission line contingent project in the next regulatory control period. It suggests that the acquisition of the land should be made a contingent project or funding should be provided to buy options to acquire the land at a future date.[143]

141 Asten, D., *Transend's transmission pricing determination*, 5 February 2009, pp. 1-2.
142 EUAA, *Submission to AER on the draft decision*, op.cit. p. 10-11.
143 ibid., p. 12.

The EUAA requested the AER review and reconcile the findings of the WorleyParsons and Nuttall Consulting reviews of Transend's capex proposal submitted in May 2008.[144]

AER considerations

Composition of Transend's asset base

The AER notes Mr Asten's queries relating to the inclusion of distribution assets in Transend's asset base. As set out in the AER's draft decision, Transend's transmission licence describes the Transend transmission network as extending "from the connection points for the Generation Sites and Transmission Sites listed … to the connection points for the Demand Sites and Transmission Sites listed". As a result, the Transend network, unlike its peers, is defined to include assets that operate at 6.6 kV, 11 kV, 22 kV, 33 kV, 44 kV, 110 kV and 220 kV. [145] Therefore, the AER concluded that sub-transmission assets are properly included in the Transend asset base.

Deliverability of proposed capex program in next regulatory control period

At the predetermination conference held in Hobart on 10 December 2008, a number of stakeholders raised the current economic circumstances and questioned the impact of the changes in economic conditions on Transend's capital expenditure proposal.

As set out in the AER's draft decision, the AER is satisfied that Transend is well positioned to physically deliver the forecast capex program (as adjusted by the AER) during the next regulatory control period.[146] This assessment was made on the proviso that Transend could adequately finance its proposed capex program.

Subsequent to the release of the AER's draft decision and the predetermination conference, Transend's revised proposal indicated that the current economic conditions would not have a significant impact on its capex proposal and, therefore, the need for capital. Given the current world economic and financial conditions, the AER sought advice from Transend's Board as to whether it was aware of any current or pending matter or circumstance which might affect Transend's ability to obtain finance for the delivery of the proposed capex program in the next regulatory control period.

In its response to the AER dated 17 February 2009, Transend's Board confirmed that neither it nor TASCORP, through which Transend raises all its debt, were aware of any circumstances that would affect Transend's ability to access funds during the next regulatory control period. The AER accepts the advice of Transend's Board on this matter.

Cost estimation risk factor

The AER does not agree with the EUAA's position that it is inappropriate to apply a cost estimation risk factor in establishing the *total* forecast capex allowance for a TNSP. The EUAA position is that Transend has not established that there is an asymmetric risk that outturn costs to be greater than forecast costs. The AER

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144 ibid., p. 8.

145 AER, *Transend draft decision,* op.cit, p.260 and Appendix B.

146 AER, *Transend draft decision,* op.cit, pp. 137-141.

considers that the cost estimation risk factor adjustment takes account of risks that are outside Transend's control when estimating project costs. WorleyParsons' detailed project review compared project cost estimates with actual costs.[147] The AER has considered the data from WorleyParsons' detailed project review together with information provided by Transend relating to capital expenditure variations from forecasts in the current regulatory control period.[148] The AER considers that Transend has sufficiently established that there is a tendency for outturn costs to be greater than forecast costs, due to factors unforeseen at the time of preparing the project cost estimates.[149]

The cost estimation risk analysis is aimed at providing efficient allowances for costs that are likely to be incurred as part of the project portfolio cost estimation process. The AER notes that Transend has identified two categories of cost risk; inherent risk and contingent risk. In developing its project estimates for the next regulatory control period, Transend has considered and applied only inherent risks.[150] In its final decision for ElectraNet, the AER acknowledged that in the inherent risk category the risk workshop using industry knowledge appeared to be a reasonable way to develop the cost boundaries as the inherent risk probability distributions were based around the base cost estimates.[151]

In the draft decision the AER considered that the base planning objects (BPOs) and base planning rates (BPRs) underlying these base cost estimates were reasonable. WorleyParsons' detailed project review confirmed that Transend did not include an adjustment for project risks in the development of the BPOs used in estimating the cost of the projects proposed for the next regulatory control period.[152] Further, the risk workshop developed upper and lower cost boundaries around these base cost estimates.

The BPOs and BPRs are the unit cost rates which are applied to individual segments of a project, the relevant BPOs are added together and built upon to generate a project cost estimate. The AER also accepted WorleyParsons' advice that Transend's base planning objects and unit rates were reasonable and provided an appropriate basis to estimate the cost of the projects comprising the forecast capex program. In the draft decision, the AER noted that Transend used recent project costs and suppliers' indicative costs to establish its base planning objects and unit rates. The AER considers the use of suppliers' current indicative costs is relevant to verifying past project costs and lends itself to achieving the stated outcome of providing efficient allowances for costs that are likely to be incurred. The AER also noted that, in

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147 WorleyParsons, *Review of the Transend revenue proposal*, op.cit, Appendix 3.

148 Response to information requests Nos. 74, 76, 77 and 78, confidential, submitted 27 August 2008—Transend, *Capital expenditure profiles and variations for the period January 2004 to June 2014 TNM-GS-809-0864*, Issue 0.4, August 2008.

149 Response to information requests Nos. 74, 76, 77 and 78, confidential, submitted 27 August 2008—Transend, *Capital expenditure profiles and variations for the period January 2004 to June 2014 TNM-GS-809-0864*, Issue 0.4, August 2008.
WorleyParsons, *Review of the Transend transmission network revenue proposal 2009-2014: An independent review prepared for the Australian Energy Regulator*, October 2008, Appendix 3.

150 WorleyParsons, *Review of the Transend transmission network revenue proposal 2009-2014: An independent review prepared for the Australian Energy Regulator*, October 2008, p. 93.

151 AER, *ElectraNet transmission determination 2008–09 to 2012–13: Final decision*, 11 April 2008, pp. 51, 127.

152 ibid., p. 40.

developing its cost estimation risk factors, Transend has not included cost variations due to cost escalations in commodities and labour markets.[153] This is consistent with establishing the benchmark capex allowance which the AER notes is a factor it must have regard to in accordance with clause 6A.6.7 of the NER.

In summary, the cost estimation risk factor is not used to adjust for differences between forecast and actual project costs. The cost risk estimation factor is applied to the project cost which has been built up using the base planning objects and unit rates. The resulting estimated project cost should be representative of the efficient cost for that project. This is the project cost which, following the application of appropriate cost escalators, is considered to be included in the approved capex allowance. In reaching its conclusion the AER assessed:

- the different risk categories and models making up the risk analysis
- the appropriateness of the workshop based inputs and the sensitivity of the risk factor on these inputs
- the potential for some risks in the proposed risk factor already being compensated for in other parts of the regulatory framework
- whether new initiatives and estimating procedures have been accounted for and
- the relationship between the size of the project portfolio and the risk factor.

Strategic acquisition of land easements

The AER's draft decision accepted Transend's proposed capex of $21 million ($2008–09) for land and easements over the next regulatory control period. The land and easements capex category comprises one project (ND1001 Strategic easement acquisition). Approximately 94 per cent of the proposed project cost relates to the acquisition of an easement for the Sheffield–Burnie new transmission line project.

The AER's draft decision approved the Sheffield–Burnie new transmission line project as a contingent project. The timing of this project is subject to load growth and potential generation development in Tasmania's north-west. The AER notes that the project must also satisfy the regulatory test in order to proceed. Irrespective of the economic conditions, the approved trigger events for the contingent project must be satisfied if the AER is to consider amending the capital expenditure allowance for the next regulatory control period to include amounts relating to the implementation of the contingent project.

WorleyParsons noted that Transend has proposed to acquire the land approximately eight years before it expects the Sheffield–Burnie 220 kV capacity upgrade project will be required under a medium load growth scenario.[154] Given the time taken to satisfy planning and development requirements prior to purchase of the land, the AER considers this is reasonable given Transend forecasts the Sheffield–Burnie new

153 AER, *Transend draft decision,* op.cit. p. 131.

154 WorleyParsons, *Review of the Transend transmission network revenue proposal 2009-2014: An independent review prepared for the Australian Energy Regulator*, 23 October 2008, Volume 2 – Appendices, p.125.

transmission line project will take four years from inception to commissioning.[155] Further, Transend has advised the AER that the total length of the easement is approximately 47 km and approximately 8 km of this has been zoned for residential development.[156] Based on this information, approximately 93 per cent of the estimated land acquisition costs relate to the acquisition of the residential zoned land.[157] The AER expects easement acquisition to be a more burdensome task as residential development increases and accepts that this is a valid consideration in Transend's planning.

The AER notes that Transend has undertaken long term strategic planning to identify network needs in the future.[158] The AER agrees with WorleyParsons' assessment that there is a case for acquisition of the easement separate from the triggering of the Sheffield–Burnie 220 kV new transmission line contingent project.[159] For the reasons discussed above, the AER does not consider the strategic easement acquisition project would be more appropriately included as a contingent project.

Options were suggested by the EUAA as a device to lower the cost of land acquisition. The AER does not consider that the actual line route and its timing is sufficiently certain to provide Transend an allowance to acquire options on the purchase of the land. Although options can be used as a transitory step or as an alternative to acquisition of land in some circumstances, their use can also introduce uncertainty and delay in the finalisation of land acquisition owing to the possibilities of legal challenges and default. Whilst an option payment may initially be cheaper than outright acquisition an option of this nature will inevitably include an obligation to ultimately complete the acquisition. It has not been demonstrated that, when measured over the whole process, that options will result in lower overall costs to consumers. It is likely that Transend will seek to employ options as a tool in its procurement process to maintain flexibility in settling a route in preference to use of compulsory acquisition powers but, in the event that compulsory acquisition is necessary options are unlikely to be an effective tool as full payment will immediately be due. The AER considers that it has not been demonstrated that options are a sufficient and viable alternative to Transend's proposal to acquire land. For the reasons discussed the AER does not consider that it should substitute the use of options for the allowance sought by Transend.

The AER does not agree with the EUAA's position that there is no strategic benefit in the early acquisition of land and easements. The AER notes that Transend has experienced project delays in the current regulatory control period directly related to

155 Transend, *Contingent project investment report – Sheffield-Burnie new transmission line TNM-PL-809-0722-028*, Issue 1.0, August 2008, p.5

156 Transend, *Request for information No. 267 per 13 October to 17 October register*, email dated 16 October 2008.

157 ibid.,

158 Transend, *Transend transmission revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 31 May 2008, Appendix 8—NOUS, *Transend networks: 30+ year network vision project final report*, May 2007.

159 WorleyParsons, *Review of the Transend transmission network revenue proposal 2009-2014: An independent review prepared for the Australian Energy Regulator*, 23 October 2008, Volume 2 – Appendices, p.125.

route planning and easement acquisition issues and considers that these issues are also likely to be significant for this proposed line.[160]

Consultant review of need for investment

The AER engaged WorleyParsons and Nuttall Consulting to provide an independent assessment of the efficiency and appropriateness of Transend's capital governance framework and capex proposal submitted to the AER as part of Transend's original proposal. Specifically, WorleyParsons was required to review Transend's capex proposal (excluding network renewal capex) and Nuttall Consulting was required to review Transend's renewal capex proposal.

As part of their respective assessments, the consultants undertook detailed project reviews of a sample of the proposed projects. The purpose of the detailed project review was twofold – to assess the prudence and efficiency of each project and to test whether Transend had complied with its stated capex policies and procedures. WorleyParsons and Nuttall Consulting provided their opinion to the AER on these matters based on their independent reviews. The AER considered this advice in making its draft decision.

The EUAA has perceived a contradiction in the AER's draft decision in relation to its acceptance of the recommendations made by WorleyParsons and Nuttall Consulting respectively. It has submitted that WorleyParsons' report to the AER contains insufficient evidence of critical review and analysis of Transend's capex proposal. The AER considers that WorleyParsons applied rigour in its assessment of Transend's ex ante capex (excluding asset renewal capex). AER staff accompanied WorleyParsons staff to many meetings with Transend at which these matters were directly canvassed and have independently reviewed the project documentation. Although WorleyParsons' report does not set out the details of its assessment, the summary comments that accompany each project confirm the project need. Timing has been considered in light of network operation and NER and Tasmanian jurisdictional obligations. Further, the efficiency and prudence of the proposed projects have been technically assessed and, in the majority of cases, WorleyParsons has indicated that it could not identify a lower cost alterative solution to that proposed by Transend.

The AER considers the differences in the conduct of, and conclusions reached, by the WorleyParsons and Nuttall Consulting reviews is well summarised by Nuttall Consulting as follows.

> It is important to note that in many renewal cases, the need, particularly the timing of the need, and the efficient investment option can be interrelated. This is different, for example, to reliability augmentations where it can be determined with some objectivity that a reliability obligation will not be complied with at a certain time based upon the available demand forecast, and therefore, the business is in a "must do something" situation. [161]

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160 WorleyParsons, *Review of the Transend transmission network revenue proposal 2009-2014: An independent review prepared for the Australian Energy Regulator*, 23 October 2008, Appendix 3 and Appendix 4.

161 Nuttall Consulting, *Review of Transend revenue proposal asset renewal capital expenditure: A report to the Australian Energy Regulator*, November 2008, p. 46.

In this regard, the need for, and timing of, the augmentation and connection projects reviewed by WorleyParsons was relatively more straightforward to assess.

In assessing the projects, the consultants considered the following matters:

- whether or not there was genuine need for the project
- whether Transend had considered the complete range of feasible alternatives
- whether the scope, cost and timing of the proposed project was efficient
- whether the project aligns with Transend's strategic plans, governance arrangements and capex policies and procedures.

The downward adjustment to the ex ante asset renewal capex was the result of Transend's failure to justify, in economic terms, the revenue it sought for the next regulatory control period.

Both WorleyParsons and Nuttall Consulting considered that Transend did not adequately discuss and quantify project risk costs.[162] The AER discussed with WorleyParsons and Nuttall Consulting jointly their views regarding the level of supporting project documentation and to identify reasons for the differences noted in their respective reports. Both firms agreed that Transend has developed an appropriate project governance framework and that, over the course of the current regulatory control period, Transend has dramatically improved its project governance and cost estimating procedures and the development of its supporting documentation. This improvement was most pronounced in relation to projects that include accountability to external parties such as directly connected customers, including Aurora Energy, and regulatory bodies.

The AER acknowledges that project priorities are subject to change. It expects Transend to be responsive to changing conditions in order to meet the prescribed capex objectives.

4.7 AER conclusion

The AER has considered Transend's revised forecast capex proposal of $711 million ($2008–09) and, for the reasons outlined in this chapter, is not satisfied that this total capex forecast proposed by Transend reasonably reflects the capex criteria under clause 6A.6.7(c):

- 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
- a realistic expectation of the demand forecast and cost inputs required to achieve the capex objectives.

162 WorleyParsons, *Review of the Transend transmission network revenue proposal 2009-2014: An independent review prepared for the Australian Energy Regulator*, October 2008, pp. 63, 140. Nuttall Consulting, *Review of Transend revenue proposal asset renewal capital expenditure: A report to the Australian Energy Regulator*, November 2008, pp.51-53.

In coming to this view, the AER has had regard to the capex factors noted in clause 6A.6.7(e).

This amended allowance set out at table 4.12 below represents the AER's estimate of the total capex that a prudent operator in the circumstances of Transend would require to achieve the capex objectives. The AER is satisfied that the amended ex ante capex allowance of $604 million over the next regulatory control period, reasonably reflects the capex criteria, taking into account the capex factors.

It is important to note that, for consistency, the AER's adjustments to the forecast capex allowance for real capex escalations has been made after applying the project adjustments set out at sections 4.6.2 , 4.6.3 and 4.6.5.

As stated in the draft decision, the AER's project-specific conclusions should not be taken to bind Transend to a particular set of project-specific capex budgets. — Transend has the ultimate discretion in how it spends its capex allowance. Transend is able to reorder its capital project priorities, including as a result of project delays, managing safety issues relating to its system assets and managing system reliability and security requirements.

Table 4.12: AER's conclusion on Transend's ex ante allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Transend proposal (31 May 2008)	158.0	173.4	106.5	118.5	124.3	680.7
AER's ex ante capex allowance (draft decision)	154.6	166.6	101.2	96.8	96.0	615.1
Transend's revised capex proposal (14 January 2009)	181.8	187.6	105.7	116.9	118.7	710.8
Adjustment for Waddamana–Lindisfarne 220 kV transmission line second circuit project	–8.2	–9.6	0.0	0.0	0.0	–17.8
Adjustment to renewal capex	–0.3	–2.2	–1.2	–8.8	–11.0	–23.5
Adjustment for assets affected by NER clause 11.6.11	0.0	0.0	0.0	0.0	–0.6	–0.6
Adjustment to escalators	–14.8	–18.7	–10.8	–9.4	–9.3	–63.1
AER's total adjustments	–23.3	–30.5	–11.9	–18.3	–20.4	–104.4
AER's ex ante capex allowance	**158.5**	**157.1**	**93.8**	**98.6**	**98.4**	**606.4**

Note: Total may not add up due to rounding.

5 Cost of capital

5.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision on Transend's weighted average cost of capital (WACC), including the averaging period of the risk–free rate, debt risk premium and inflation forecast raised by Transend in its revised revenue proposal.

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 6 and the analysis of corporate tax is found in chapter 9 of this final decision.

5.2 AER draft decision

In the draft decision, the AER determined a nominal vanilla WACC of 9.64 per cent for Transend. The WACC was greater than that proposed by Transend, which based its proposed WACC on the historical average of the cost of debt. The WACC determined by the AER reflected increased corporate debt costs associated with developments in international financial markets.

Table 5.1 outlines the WACC parameter values determined for the draft decision. The AER stated it would 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 5.1: AER's conclusion on WACC parameters

Parameter	Transend's proposal	AER Conclusions
Risk–free rate (nominal)	6.37%	5.27%
Risk–free rate (real)		2.66%
Expected inflation rate	2.54%	2.55%
Debt risk premium	3.13%	3.28%
Market risk premium	6.00%	6.00%
Gearing	60%	60%
Equity beta	1	1
Nominal pre–tax return on debt		8.55%
Nominal post–tax return on equity		11.27%
Nominal vanilla WACC	10.65%	9.64%

Source: AER, *Transend draft transmission determination*, 21 November 2008, pp. 154-55.

5.3 Transend's revised regulatory proposals

In its revised revenue proposal, Transend did not agree with the AER's approach to the averaging period for the risk-free rate and the debt risk premium. Transend proposed that the averaging period for the risk-free rate and the debt risk premium be revised to exclude the impacts of the global financial crisis. It also proposed alternative methodologies for estimating the debt risk premium and for deriving expected inflation.

5.4 Submissions

The AER received three submissions on the cost of capital, from RTA Bell Bay, MEG and Nyrstar.

5.5 Issues and AER considerations

5.5.1 Risk free rate

Averaging period

Transend initially proposed averaging periods for the nominal risk free rate of 10 business days commencing 30 days following lodgement of Transend's revenue proposal. In July 2008, the AER determined that the proposed averaging periods was unreasonable and informed Transend of the AER's decision.[163]

The AER rejected the Transend's proposed averaging period on the basis that it was too far removed from the date when the AER would publish the final decision. The AER also noted that such an averaging period would be inconsistent with previous regulatory practice by the AER, ACCC and jurisdictional regulators, which set the averaging period for the risk free rate at a date close to the final decision. The AER advised that this regulatory practice was supported by finance literature and cited papers by Associate Professor Martin Lally and Professor Kevin Davis.[164]

In July 2008, the AER advised Transend that the risk free rate would be based on a 10 business day averaging period commencing on 9 March 2009 and ending on 20 March 2009. The AER invited Transend to nominate an averaging period between 1 February 2009 and 20 March 2009 if they disagree with the AER's nominated averaging period. Transend did not respond to the AER's request to nominate an alternative averaging period between 1 February 2009 and 20 March 2009.

AER draft decision

In the draft decision, the AER determined a nominal risk free rate of 5.27 per cent based on a 10 day moving average of yields on Commonwealth Government

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163 AER, *Letter to Transend: Transend's proposed nominal risk free rate averaging period for the 2009–2014 regulatory control period*, July 2008.

164 Martin Lally, *The cost of capital for regulated entities, report prepared for the Queensland Competition Authority*, 26 February 2004, p. 63; Martin Lally, *Determining the risk free rate for regulated companies, report prepared for the ACCC*, August 2002, p. 17; and 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.

Securities (CGS) with a 10 year maturity for the period ending 17 October 2008.[165] The AER noted that the risk free rate would be updated, based on the agreed averaging periods, at the time of the final decision. The agreed averaging periods was not disclosed due to a request by Transend for the period to be kept confidential.

Transend revised revenue proposal

Transend commissioned Competition Economists Group (CEG) to provide a report on the selection of an averaging period for the determination of the risk free rate. The CEG report was provided as an attachment to Transend's revised regulatory proposal.[166]

The CEG report recommended that the AER set an averaging period for the risk free rate prior to September 2008 because the global financial crisis became worse at that time, best characterised by events such as Fannie Mae and Freddie MAC in the US being placed in conservatorship on 7 September 2008.[167]

CEG stated that the global financial crisis has resulted in downward biased yields on 10 year nominal CGS and noted that:

- The global financial crisis has increased volatility across the Australian equity market and caused a flight to safety, which has decreased yields on nominal CGS and increased the cost of equity.[168]
- The spread between yields on 10 year CGS and 10 year state government bonds is at historically high levels due to a liquidity premium being paid for CGS.[169]
- There has been a sudden fall in the 10 year break even inflation rate, which is either due to investors' increased demand for nominal CGS or alternatively lower inflation expectations.[170]

CEG stated that the NER require an averaging period for the risk free rate to be chosen such that it results in an adequate rate of return: [171]

> Other things being equal, the optimal averaging period is one that is most consistent with providing an accurate estimate of the cost of equity and debt for the regulated business. That is, a cost of equity and debt that, when inserted into the WACC formula in the Rules provides a rate of return to the regulated business equivalent to that required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by the regulated business.

165 AER, *Transend transmission determination 2008–09 to 2013–14: draft decision,* 21 November 2008, p. 154.
166 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009.
167 ibid., pp. 30-32.
168 ibid., pp. 34-38
169 ibid., pp. 38-40
170 ibid., pp. 44-45
171 ibid., p. 7

CEG stated that an averaging period subject to market conditions post September 2008 would result in an estimate of the cost of equity under the NER that results in a rate of return inconsistent with clause 6A.6.2(b) of the NER.[172]

CEG stated that the reports by Lally and Davis, which the AER cited in its letters to the Transend rejecting their proposed averaging periods, do not support the AER's averaging period decision. CEG stated that these reports state:[173]

- an averaging period is used to minimise exposure to rates on an aberrant day
- a market risk premium based on historical data should not be accepted uncritically and the market risk premium can be expected to vary over time.

CEG stated that, when "properly construed," the Lally and Davis reports support the use of an averaging period that avoids the current market conditions because the current market conditions are aberrant and that the market risk premium is fixed based on historical data.[174]

CEG stated that previous regulatory decisions in Australia[175] as well as decisions in the UK and the US, have adjusted the averaging period for the risk free rate to account for specific events. CEG stated that these decisions support the use of an averaging period that excludes the impacts of the global financial crisis.[176]

CEG stated that there is a basis for concluding that an averaging period close to the final decision date could result in an inaccurate proxy for a regulated business' actual cost of debt, in the current market conditions. CEG stated that a business' actual debt costs are likely to be hedged over an extended period of time, so the AER's approach to estimating the cost of debt over one single averaging period may not be reflective of the actual cost of debt for a regulated business.[177]

CEG stated that, consistent with TransGrid's revenue proposal, there are valid reasons for a business to prefer to have certainty about the rate of return it can earn prior to deciding on a capital expenditure program.[178]

Based on the CEG report, Transend proposed a nominal risk–free rate of 4.66 per cent, based on a 10 day averaging period ending on 1 December 2008.[179]

Submissions

The Major Employers Group[180] objected to Transend's proposal to use different methodologies to set inflationary expectations and stated that the risk free rate is a

172 CEG, *Rate of return and the averaging*, op. cit. p. 12
173 ibid., p. 13
174 ibid., p. 14
175 ACCC, *Powerlink revenue cap decision*, November 2002; ESCV, *Final decision electricity distribution price review 2006–10 as amended by the appeal panel decision,* dated 17 February 2006, October 2006
176 CEG, *Rate of return and the averaging period*, op. cit. p. 16
177 ibid., pp. 19-25, 26.
178 ibid., p. 26-28.
179 Transend, *Revised regulatory proposal 2009-2014*, 16 January 2009, p. 45.

case of not liking the outcome and thus seeking to change the rules. They believe there is no danger that Transend's returns would suffer to the point that it would not make investments, using the current risk free rate and implied inflationary expectations.

Nyrstar[181] objected to Transend's recommendation to vary the averaging methodology on the basis of 'dislocation' in the credit/financial markets. Nyrstar did not have any issues with the AER's forecast inflation nor the derivation of the debt margin using the AER methodology.

AER considerations

The AER's detailed considerations of Transend's revised averaging period are presented in appendix E of this final decision. The AER notes that the consultancy reports submitted by TransGrid on this matter are also applicable to the AER's considerations concerning Transend's revised revenue proposal and the revised regulatory proposals of the ACT/NSW DNSPs. The AER considers that its approach should be consistent across each of these businesses. Accordingly, appendix E sets out the AER considerations of all material submitted as part of the current regulatory process and is applicable to TransGrid, Transend and the ACT/NSW DNSPs.

In summary, the AER considers that its decision to withhold agreement to the averaging period in Transend's revenue proposal was reasonable and that the agreed averaging period is consistent with finance theory, regulatory practice, the NER and NEL.

The AER considers the use of an averaging period as close to the start of the next regulatory control period as practically possible is consistent with the forward looking nature of the CAPM and is correct in finance theory. The AER notes that given the evidence at the time, the additional material contained in the revised revenue proposal does not justify a conclusion that the AER's decision to withhold agreement to the proposed averaging period and consequently the agreed averaging period was inconsistent with regulatory practice.

The AER notes that the arguments put forward by Transend regarding the insufficiency of the return on equity is based on the view that the MRP of 6 per cent in the NER (based on a historical average) is out of line with the current variations in the MRP. In essence, Transend is arguing for a variable MRP to be applied in the CAPM. However, given that the MRP is prescribed in the NER, Transend appeared to suggest that it is reasonable to account for variations in the MRP via adjustments to the risk-free rate. The AER notes that adjusting the risk-free rate averaging period as a mechanism to achieve the outcome equivalent to adopting a higher MRP (due to implied or actual variations to the historical MRP) is an attempt to circumvent WACC parameters prescribed (subject to 5 yearly reviews) in the NER and would undermine the intended certainty under the regulatory regime which results from these values being prescribed..

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180 Major Employer Group, *Submission to AER on the Transend transmission revised revenue proposal*, February 2008, p. 3-4.

181 Nystar, *Submission to Transend's revised revenue proposal*, February 2007, p.4.

The fact that CGS bond yields are at (or close to historical lows) does not of itself mean they cannot be used. Interest rates move all the time and reflect the markets assessment of the price of money at the time. Expectations about the prospect for prices and growth will influence this assessment. If Transend can lock in an averaging period that it considers achieves the most advantageous rate of return early in the regulatory process based on its view on future interest rate movements then it may create opportunities for 'gaming' the regulator if its view transpires to be disadvantageous. In June 2008 when the AER received Transend's revenue proposal the interest rate yield curve was downward sloping. The downward sloping yield curve at that time reflects market expectations of lower interest rates in the future. Therefore, setting the risk-free rate based on an averaging period at that time would have lead to systematic ex ante overcompensation of firms relative to the efficient cost of capital and inconsistent with the forward looking nature of CAPM—that is, it would not result in an unbiased risk-free rate.

The AER considers that the material provided by Transend in support of its revised revenue proposal does not reasonably justify that, an averaging period prior to September 2008 is better than a period that is as close as practically possible to the start of the next regulatory control period. Moreover, the agreed averaging period does not exclude the downward movement of the CGS yields commensurate with an easing in monetary policy and a softening in economic growth. The AER considers that the agreed averaging is not abnormal and setting the risk free-rate using this period is also consistent with the NEL objective of efficient investment. The AER therefore considers that the agreed averaging period does not represent an abnormal period in relation to the observed CGS yields.

The AER considers that Transend is not deprived of a reasonable opportunity to recover its efficient cost of capital and notes that a comparison of the WACC across regulatory control periods show that the WACC for the next regulatory control period—although lower—is reasonable compared to the WACC in the current regulatory control period.

The nominal risk-free rate averaging period that the AER has adopted for this final decision is 10 business days commencing 9 March 2009 and ending 20 March 2009. The 10 business day moving average for CGS yields[182] with a 10-year maturity for the period ending 20 March 2009, results in a proxy nominal risk-free rate of 4.30 per cent (effective annual compounding rate).

5.5.2 Debt risk premium

AER draft decision

In the draft decision, the AER determined a benchmark debt risk premium of 3.29 per cent, which was added to the nominal risk-free rate to determine the return on debt for the WACC calculation.[183] The debt risk premium was calculated using Bloomberg estimates of fair yields on long term corporate bonds, based on an averaging period of

182 RBA, CGS yields at: http://www.rba.gov.au/Statistics/indicative.html.

183 AER, *Transend transmission determination 2008–09 to 2013–14: draft decision,* 21 November 2008, p.151.

15 business days ending 17 October 2008—consistent with the averaging period for the risk-free rate.[184]

The AER used Bloomberg estimates rather than CBASpectrum estimates for the fair yields of 10 year BBB+ rated corporate bonds based on the results of a review conducted during previous revenue determinations.[185] The review concluded that Bloomberg provided better estimates of 10 year BBB+ fair yields than CBASpectrum because Bloomberg estimates of yields of similarly rated corporate bonds were more consistent with the actual observed yields on these bonds. The AER noted that the debt risk premium would be updated, based on the agreed averaging period, at the time of the final decision.

Transend revised regulatory proposals

Transend commissioned CEG to provide a report, which addressed the calculation of the debt risk premium. Based on the CEG report, Transend proposed that the debt risk premium be calculated using a 10 day averaging period ending 1 December 2008, consistent with the averaging period for the risk-free rate.

Transend did not agree with the AER's methodology and cited the CEG report's analysis that the current lack of liquidity in the market for existing BBB+ corporate bonds means that neither Bloomberg nor CBASpectrum data are likely to give a reliable estimate of bond yields. The CEG report suggested that rather than relying solely on Bloomberg or CBASpectrum estimates, the AER could take a simple average of estimates from Bloomberg and CBASpectrum data to provide a more reliable estimate.[186]

Based on a simple average of estimates from Bloomberg and CBASpectrum, and an averaging period of 10 business days ending on the 1 December 2008, Transend proposed a debt risk premium of 3.86 per cent.[187]

Submissions

Rio Tinto Alcan's (RTA) Bell Bay submission[188] stated that in Transend's revised revenue proposal, it has proposed a new methodology for the calculation of its debt margin. Clause 6A.12.3(b) does not permit Transend to revise its revenue proposal in this way, and even if it did, the AER should stand by its draft decision because Transend should not be able to re-open this issue simply because it believes it can achieve a more favourable outcome using data produced by CBASpectrum.

AER considerations

The AER notes that Transend's regulatory proposal did not propose the use of CBASpectrum or Bloomberg fair yield estimates in the calculation of the debt risk premium. A significant divergence has developed over the past nine months between

184 ibid.

185 ibid.

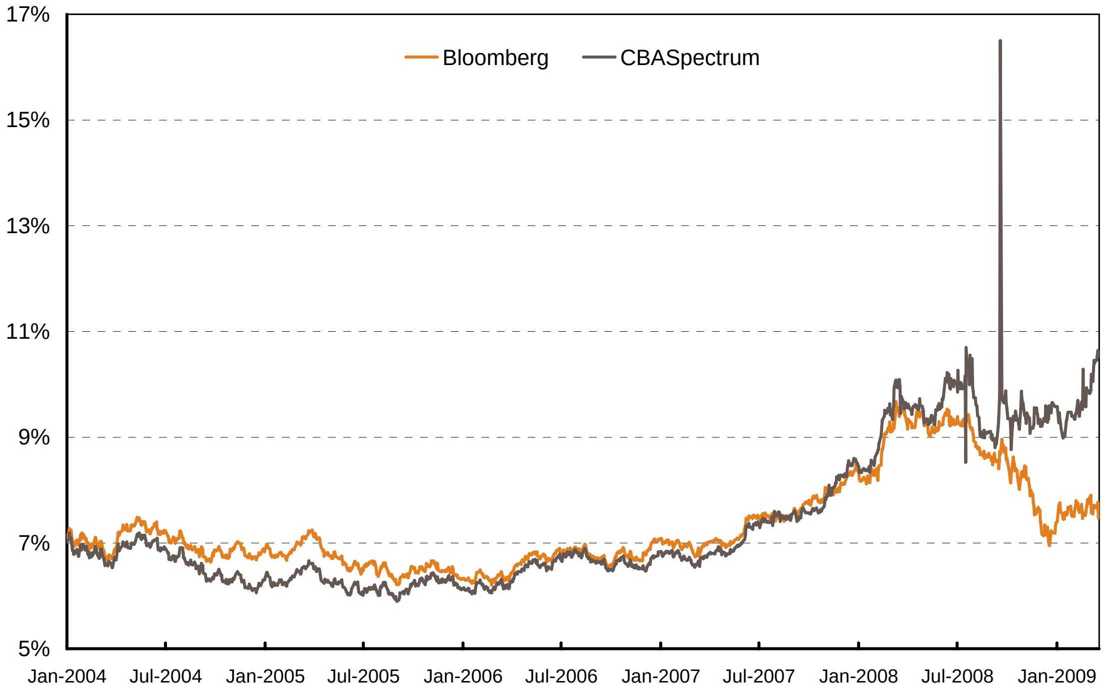
186 CEG, *Rate of return and the averaging period*, op. cit. p. 57.

187 Transend, *Revised revenue proposal*, p. 51.

188 RTA, *Transend revenue cap 2009/10-2013/14: submission by Rio Tinto Alcan (Bell Bay) in response to the draft decision of the AER*, February 2009, p. 12.

the corporate bond fair yields reported by Bloomberg[189] and CBASpectrum, as displayed in figure 5.1. Since January 2009, the Bloomberg BBB+ 10 year fair yield has remained relatively steady while the CBASpectrum fair yield has risen sharply. Consequently the difference in the two fair yields surpassed three percentage points on 19 March 2009.

Figure 5.1: BBB+ 10 year fair yield estimates



Source: Bloomberg, CBASpectrum and AER analysis.

In previous revenue determinations the AER compared the estimated average daily fair yields for corporate bonds with a BBB+ credit rating from the Bloomberg and CBASpectrum databases.[190] The review indicated that Bloomberg provided estimates of BBB+ rated long-term fair yields that were more consistent with the observed yields of similarly rated actual bonds. However, given the current divergence between the two data sources the AER agrees with Transend that the fair yields reported by the two sources should be reviewed again.

To undertake the analysis, the AER first identified the BBB+ rated bonds with a maturity of at least two years, which are listed in table 5.2. The AER then compared the actual yields of these bonds as quoted by Bloomberg with the fair yields quoted by Bloomberg and CBASpectrum.[191] The AER compared the actual observed bond

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189 Bloomberg's BBB fair yields are assumed to approximate BBB+ fair yields due to the estimation technique employed and the market being disproportionately weighted with longer term BBB+ rated bonds. Due to a lack of long term BBB+ or similar rated bonds, Bloomberg does not report a 10 year BBB+ fair yield. As set out in the draft decision, the AER has derived the BBB+ 10 fair year yield by adding the spread between the A rated 8 and 10 year fair yields to the BBB+ 8 year fair yield.

190 AER, *Draft decision Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12,* , 8 December 2006, pp. 103–104; and AER, *Directlink Joint Venturers' application for conversion and revenue cap: Decision*, 3 March 2006, pp. 211, 221.

191 For each bond, fair yields were calculated for each day by linear interpolation of the two fair yields that straddled the maturity of the bond.

yields with the fair yields over the period from 2 February to 20 March, covering the averaging periods for the NSW DNSPs, ActewAGL, TransGrid and Transend. The average actual yields, and the average Bloomberg and CBASpectrum fair yields over the period analysed are outlined in table 5.2.

Table 5.2: BBB+ rated bonds with a maturity of two years or greater

Issuer	Maturity	Average observed yield (per cent)		Average fair value (per cent)	
		Bloomberg	**CBASpectrum**	**Bloomberg**	**CBASpectrum**
Origin Energy	6 October 2011	6.084	Not reported	6.202	7.698
Tabcorp	13 October 2011	6.295	6.446	6.213	7.710
Lane Cove Tunnel	9 December 2011	Not reported	9.755[a]	6.301	7.808
Coles Group	25 July 2012	6.647	6.412	6.699	8.162
Snowy Hydro	25 February 2013	6.891	7.797	7.082	8.473
Lane Cove Tunnel	9 December 2013	Not reported	11.135[a]	7.195	8.797
Santos	23 September 2015	7.384	8.053	7.396	9.327
Babcock & Brown Infrastructure Group	9 June 2016	7.487[b]	12.958	7.473	9.472
Adelaide Airport	20 September 2016	7.280[b]	Not reported	7.504	9.524

Source: Bloomberg, CBASpectrum and AER analysis

(a) The yields of the two Lane Cove Tunnel bonds did not change during the period indicating that the bonds were illiquid and no trades had occurred.

(b) The yield reported by Bloomberg was an estimation of the fair price of this bond when compared with bonds in the same sector not a traded price.

Three measures were used to test the differences between the actual reported yields and the fair yields reported by CBASpectrum and Bloomberg: [192]

- mean daily difference
- mean daily absolute difference
- mean daily squared difference

In the analysis the Origin Energy bond was excluded because CBASpectrum did not report yields for this bond. The two Lane Cove Tunnel bonds were excluded because the bonds were illiquid and Bloomberg did not report yields for them. The Babcock

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192 The mean daily difference is the arithmetic mean of the difference between the actual yield of each bond and its corresponding estimated fair yield calculated daily. The mean daily absolute difference is the arithmetic mean of the absolute difference between the actual yield of each bond and its corresponding estimated fair yield calculated daily. The mean daily squared difference is the arithmetic mean of the difference between the actual yield of each bond and its corresponding estimated fair yield squared, calculated daily.

and Brown Infrastructure Group and the Adelaide Airport bonds were excluded because the yields reported by Bloomberg were fair yield estimates not yields based on prices from observed trades. The results of this analysis are summarised in table 5.3.

Table 5.3: Fair yield analysis results with Bloomberg observed yields

	Bloomberg	CBASpectrum	Average fair yield
Mean daily difference (per cent)	–0.023	1.526	0.751
Mean daily absolute difference (per cent)	0.138	1.526	0.751
Mean daily squared difference (per cent squared)	0.029	2.415	0.602

Source: Bloomberg, CBASpectrum and AER analysis.
Note: The average fair yield represents the average of the Bloomberg and CBASpectrum fair yields.

As outlined in table 5.3, the mean daily difference between the fair yield and the actual yield was much closer to zero for Bloomberg fair yields. Using Bloomberg fair values also gave a significantly lower mean daily absolute difference and mean daily squared difference. The fact that for the CBASpectrum fair yields the mean daily difference equalled the mean daily absolute difference indicates that for every day included in the analysis the CBASpectrum fair yield was higher than the actual yield reported by Bloomberg for every BBB+ bond with a maturity of at least two years. This analysis suggests that the CBASpectrum fair yields were biased upward in the period from 2 February 2009 to 20 March 2009.

Table 5.4: Fair yield analysis results with CBASpectrum observed yields

	Bloomberg	CBASpectrum	Average fair yield
Mean daily difference (per cent)	-0.329	1.241	0.456
Mean daily absolute difference (per cent)	0.618	1.275	0.659
Mean daily squared difference (per cent squared)	0.610	1.977	0.645

Source: Bloomberg, CBASpectrum and AER analysis.
Note: The average fair yield represents the average of the Bloomberg and CBASpectrum fair yields.

When the observed bond yields reported by CBASpectrum are used, the mean daily difference between the fair yield and the observed yield is again closest to zero for Bloomberg fair yields. In fact, Bloomberg fair yields again perform best for all three measures. Again, the results for CBASpectrum fair yields are the least favourable for all three measures. The results in table 5.4 also reflect the fact that the observed bond yields reported by CBASpectrum were mostly higher than the observed yields reported by Bloomberg.

The AER notes that during the period analysed Bloomberg did not report observed yields for all bonds for all trading days. Since late 2007, there have been significant periods of time for which observed yields have not been quoted for particular bonds due to illiquidity in the corporate bond market. The AER notes that it was during late 2007 that the Essential Services Commission of Victoria (ESCV) tested the fair yields of Bloomberg and CBASpectrum for its 2008 gas access arrangement review. As noted by CEG, the ESCV stated in its review that:.[193]

> …the analysis conducted in the estimation of the debt premium (below) shows that CBASpectrum has performed better in predicting bond yields than Bloomberg under current market conditions

This was one of the conclusions of the Allen Consulting Group (ACG)[194] which undertook the analysis referred to by the ESCV. In its report, ACG stated that it considered that: [195]

> … the suggested error in fair yield predictions of Bloomberg of -2 to 4bp is not material and the absence of material over-prediction is consistent with there being no broader theoretical or empirical reasons to suggest that Bloomberg systematically errs in its predictions of fair-value yields.
>
> The suggested error in the CBASpectrum fair-yield predictions is greater than for Bloomberg and, importantly, suggests over-estimates of yields contrary to indications in mid 2007 of systematic negative bias in CBASpectrum fair yield predictions.

At first glance this quote appears inconsistent with the ESCV quote and suggests that the analysis conducted by ACG indicated Bloomberg, not CBASpectrum, performed better in predicting bond yields under the market conditions prevalent during the 20 days business days to 21 December 2007. In fact, the ACG analysis found that over the 20 business days to 21 December 2007 Bloomberg overestimated bond yields by 3.2 basis points on average while CBASpectrum overestimated yields by 17.6 basis points.[196]

However, ACG concluded that: [197]

> As the debt margins derived from Bloomberg relied on extrapolation of fair value yields for 7 and 8 year bonds rather than direct predictions, we suggest that greater weight may be given to the debt margins derived from CBASpectrum, and hence the higher values in these ranges.

Consequently, it appears that the basis for the conclusion that CBASpectrum performed better in predicting bond yields than Bloomberg under the market conditions at that time was because CBASpectrum provided a 10 year BBB+ fair yield estimate while Bloomberg only estimated fair yields for maturities up to eight years.

The AER therefore does not consider that the ACG analysis conducted for the ESCV indicated that CBASpectrum performed better at predicting BBB+ bonds yields than Bloomberg. Rather, the AER considers that the ACG analysis found that Bloomberg performed better than CBASpectrum at predicting BBB+ bond yields for bonds with a maturity up to eight years. Because the longest term to maturity of the bonds considered by ACG was eight years the analysis does not indicate whether Bloomberg

193 ESCV, *Gas access arrangement review 2008–2012: Final decision*, 7 March 2008, p. 487.

194 The ACG, *Memorandum: Gas access arrangement review 2008: updating estimates of debt margins for 20 trading days to November 2007 and December 2007, 25 January 2007*, p. 4.

195 The ACG, *Memorandum*, p. 8.

196 The ACG, *Memorandum*, p. 7.

197 ibid., p. 8.

or CBASpectrum performed better at predicting the fair yield of BBB+ bonds with a 10 year maturity.

In its final decision for SP AusNet, the AER tested both the CBASpectrum 10 year BBB+ fair yield and the extrapolated Bloomberg BBB eight year fair yield to test which was the best proxy for the Bloomberg BBB 10 year fair yield. The two fair yields were tested over the 18 month period to October 2007 when Bloomberg ceased publishing a BBB 10 year fair yield. The analysis found that the eight year Bloomberg BBB fair yield plus the spread between the eight and 10 year Bloomberg A fair yields was the best proxy over the sample period.[198]

Consequently, the AER considers that the ACG analysis conducted for the ESCV, when considered alongside the analysis the AER undertook in its final decision for SP AusNet, indicates that Bloomberg, not CBASpectrum, performed better in predicting bond yields under the market conditions prevalent during the 20 business days to 21 December 2007.

In conjunction with the analysis that compared observed BBB+ bond yields with the fair yield estimates of Bloomberg and CBASpectrum, the AER has also reviewed the methodologies adopted by these data providers.

The AER notes that the methodologies adopted by Bloomberg and CBASpectrum to estimate fair yields are significantly different. The AER understands, based on work undertaken by NERA, that CBASpectrum fair yield estimates for bonds with a given credit rating are based on observed yields for bonds of all credit rating. Thus, the BBB+ 10 year fair yield will be a function of not only the observed yields of BBB+ bonds but also the yields of long dated bonds with other credit ratings. By contrast, Bloomberg's BBB fair yield curve estimates are based only on the observed yields of a sample of BBB–, BBB and BBB+ corporate bonds.[199]

The AER considers that the two methodologies have different strengths and weaknesses. Currently there is a shortage of long dated BBB bonds in the market. This, combined with the methodology it adopts, has resulted in Bloomberg discontinuing its 10 year BBB fair yield.

CBASpectrum, on the other hand, draws on observed yields for all bond ratings when calculating its fair yield for a given rating, thus enabling it to estimate a 10 year BBB+ fair yield estimate. However, in doing so it makes a number of assumptions such as the functional form of the yield curves and that yield curves of different ratings do not cross. Because of these assumptions, when tested against observed bond yields the Bloomberg fair yield estimates for similar rated bonds will usually be found more in alignment.

Another important consideration when comparing the fair yields of Bloomberg and CBASpectrum is the observed yields used by the two data providers to estimate their fair yield curves. This is particularly important in the current economic climate where the trading of a significant number of bonds is either thin or non–existent. Because

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198 AER, *Final decision: SP AusNet transmission determination: 2008-09 to 2013-14*, January 2008, pp. 95–98

199 NERA, *Critique of available estimates of the credit spread of corporate bonds*, May 2005.

bonds are typically traded 'over the counter' rather than on a centralised exchange it can be difficult to observe the market price. The AER understands that CBASpectrum's observed yields are based only on trades that the Commonwealth Bank participates in. By contrast, Bloomberg's observed yields are based on trade information provided to it by a wide range of different financial institutions. Consequently, the AER considers that the observed bond yields reported by Bloomberg provide a better reflection of the true market price than those reported by CBASpectrum.

In reviewing the CBASpectrum methodology, the AER noted that the credit ratings reported by CBASpectrum were sometimes outdated. For example, Babcock and Brown Infrastructure was rated, as at March 2009, as A– in CBASpectrum despite it being re-rated as BBB+ by Standard and Poors on 6 June 2008. The AER considers that in the current economic climate, where bonds are more likely to be re-rated downward than upward, any delay in updating credit ratings will result in an upward bias to the fair yield estimates of CBASpectrum.

To the extent that the observed bonds used to calculate the fair yields are quite different the AER considers that this is the most probable cause of the discrepancy in the fair yield estimates of CBASpectrum and Bloomberg. If the observed bonds used were all representative of the credit rating under consideration, then that alone would give rise to only minor sampling variations. However, the key problem is that the market perceived credit rating of all bonds is continually changing and a bond's credit rating may no longer reflect the market perceived credit rating. As a result of the global financial crisis many existing bonds are no longer regarded by markets as being of investment grade, and pricing and yields change to reflect this. In the current economic climate some bonds are reporting extremely high yields indicating that investors no longer consider those bonds to be of investment grade.

The AER considers that these bonds, which are no longer considered by the market as being of investment grade, should not be included in any sample of bonds used to estimate an efficient benchmark debt risk premium. The AER notes that Bloomberg publishes the bonds, and corresponding yields, that it uses each day to estimate its BBB fair yield curve. The AER reviewed the bonds used by Bloomberg to estimate its BBB fair yield curve during the averaging period (February to March 2009) and found no significant variability in the yields that might suggest inappropriate sample selection. Despite directly contacting CBASpectrum, the AER, has been unable to confirm which bonds CBASpectrum uses to estimate its fair yields and if it removes any outliers.

The AER also notes that the CBASpectrum fair yields exhibit significantly more variability than the Bloomberg fair yields (see figure 5.1). For example, the CBASpectrum BBB+ 10 year yield had risen to 16.5 per cent on 19 September 2008 from 9.9 per cent the previous day. The next day it returned to 9.8 per cent. The cause of this volatility is unclear.

On 3 April 2009 the AER received a further submission from TransGrid that included a memorandum from CEG.[200] The memorandum noted that on 24 April 2009 Tabcorp announced a five year bond issue, to be rated BBB+, which CEG claimed provided

200 CEG, *Memorandum: Evidence from recent capital issues in Australia*, 3 April 2009.

evidence that CBASpectrum fair value estimates are more accurate than Bloomberg fair value estimates post September 2008.[201]

The AER notes that the prospectus for the proposed Tabcorp five year bond issue outlines the interest payable on the proposed bonds will be a variable interest rate. The variable interest rate will be set for each interest period equal to a 'market rate' plus a 'margin'. [202] The 'market rate' will be the 3-month bank bill rate[203] plus a 'margin' of 4.25 per cent.[204] As at 23 March 2009, the initial interest rate would be 7.28 per cent.[205] The AER notes that on 23 March 2009 the Bloomberg five year BBB fair yield was 7.41 per cent and the CBASpectrum five year BBB+ fair yield was 9.67 per cent. Further, the AER notes that the fair yields represent estimates for fixed interest bonds, not variable interest bonds. While there are ways of converting the yield of a variable rate bond to the yield of an equivalent fixed rate bond, the AER does not consider it appropriate to compare the yields on variable rate bonds with those of fixed rate bonds for the purpose of assessing the fair yield estimates from Bloomberg and CBASpectrum.

Given these considerations, the AER is of the view that Bloomberg fair yields are a better predictor of observed yields than an average of Bloomberg and CBASpectrum fair yields or CBASpectrum fair yields alone. Consequently, the AER does not consider it reasonable to use an average of the Bloomberg fair yield and the CBASpectrum fair yield to derive the Australian benchmark rate for corporate bonds with a maturity of 10 years and a credit rating of BBB+. The AER therefore maintains its draft decision to use Bloomberg fair yields for the purposes of determining the benchmark debt risk premium for the Transend.[206]

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. Transend has proposed that the averaging period for the debt risk premium should be consistent with the risk-free rate. For this final decision, the 10 business day moving average benchmark debt risk premium for the period ending 20 March 2009, based on BBB+ rated corporate bonds with a maturity of 10 years, is 3.49 per cent (effective annual compounding rate). Adding this debt risk premium to the nominal risk free rate of 4.30 per cent provides a nominal return on debt of 7.79 per cent. The AER is satisfied that the debt risk premium is consistent, under clause 6A.6.2(e) of the NER, 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.

201 ibid., p. 1.

202 Tabcorp, *Tabcorp bonds: prospectus for the issue of five year Tabcorp bonds to be listed on ASX*, 24 March 2009, p. 6.

203 ibid.

204 Tabcorp, *Tabcorp bonds margin now set and offer now open*, 1 April 2009, p. 1.

205 The Tabcorp bond prospectus (on page 1) states that the initial interest rate would be between 7.03 per cent and 7.53 per cent. Based on the confirmed margin of 4.25 per cent this equates to an initial interest rate of 7.28 per cent.

206 The fair yield as a proxy for the corporate bond yield less the CGS yield as a proxy for the risk-free rate produces the debt risk premium.

5.5.3 Expected inflation

AER draft decision

The AER determined a 10 year inflation forecast of 2.55 per cent per annum. The inflation forecast was based on a simple average of the Reserve Bank of Australia's (RBA) forecasts of short term inflation—currently extending out to two years—and the mid–point of the RBA's target inflation band for the remaining years in the 10 year period.

The AER did not accept Transend's approach to inflation forecasting, which was based on advice commissioned from CEG. Transend's inflation forecast was calculated using a weighted average mean of professional economic forecasters' short and the mid–point of the RBA's long–term target inflation band.[207]

The AER determined that, consistent with its recent transmission determinations, an inflation forecasting methodology based on RBA inflation forecasts and the mid-point of the RBA's target inflation band is objective and represents the best estimate of forecast inflation.[208] The AER noted that the inflation forecast would be updated using the latest forecasts at the time of the final decision.

Transend revised revenue proposal

Transend stated that it would accept the use of the RBA's inflation forecasts, but only if the AER adopted Transend's revised revenue proposal averaging period for the nominal risk–free rate. Transend commissioned CEG to provide a report, which addressed the calculation of expected inflation. The CEG report was provided as an attachment to Transend's revised revenue proposal.

CEG stated that continuing the draft decision methodology would result in two critical inconsistencies in current market conditions, which are:

- providing a real risk free rate below the CGS indexed bond yields which are already an unreliably low benchmark
- adopting an inflation forecast above the break even (market inferred) inflation can only be supported if it is assumed that the nominal CGS yields are distorted by the financial crisis.[209]

CEG stated that the above inconsistencies could be addressed using one of the following approaches:[210]

- retain the nominal CGS as the proxy for the nominal risk free rate but use the break-even inflation rate if it is less than the inflation forecast based on RBA projections

207 AER, *Transend draft transmission determination*, op. cit. p. 152.
208 ibid., p. 153.
209 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 64-65.
210 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 65.

- use 10 year indexed CGS to estimate the real risk free rate and add RBA inflation projections to it to determine the nominal risk free rate.

Submissions

The Major Employers Group, Nyrstar and RTA Bell Bay[211] argued that the AER should maintain the forecast inflation methodology of the draft decision rather than the approach proposed by Transend.

RTA Bell Bay also state that Transend's proposal that the AER should develop two approaches, and use whichever produces the lowest result is arguing, in effect, that the AER should not use its best estimate of inflation, but the figure that produces the outcome most favourable to Transend. This is not the outcome required by clause 6A.5.3(b)(1) of the NER.

AER considerations

In previous transmission determinations the AER has determined 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 AER notes that Transend initially proposed an inflation forecasting methodology broadly similar to that applied by the AER in the draft decision and previous determinations[212] based on advice from CEG.[213] In April 2008, CEG agreed with the AER's methodology and did not use break-even inflation to estimate the expected inflation rate due to concerns over the use of indexed CGS.

The AER considers that, due to a lack of liquidity in the indexed CGS market, previous concerns over using the break even inflation rate to provide a best estimate of expected inflation remain valid. As outlined in the AER’s 2007 SP AusNet draft decision,[214] the Australian Government has not issued indexed CGS since February 2003. This raised questions of liquidity in the indexed CGS market. The Australian Office of Financial Management (AOFM), under direction of the Australian Government, has not reversed the decision to cease issuing indexed CGS and states that no further issuance is in prospect.[215] The AER therefore considers that the lack of supply and liquidity in the market for indexed CGS appears not to have abated.

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211 Major Employer Group, *Submission to AER on the Transend transmission revised revenue proposal*, February 2008 p. 3-4. Nystar, *Submission to Transend’s revised revenue proposal*, February 2007, p. 5. RTA, *Transend revenue cap 2009/10-2013/14: submission by Rio Tinto Alcan (Bell Bay) in response to the draft decision of the AER*, February 2009, p. 11-12.

212 The difference between the AER's approach and CEG's suggested approach is the sources used to establish the 10 year inflation forecast. CEG's suggested approach drew on forecasts from a number of economic forecasters and the RBA’s mid-point target band, while the AER relied on RBA inflation forecasts and the mid-point of its target band.

213 CEG, *Expected inflation estimation methodology*, April 2008.

214 AER, *SP AusNet transmission determination 2008–09 to 2013–14: draft decision*, 31 August 2007, pp. 114-124.

215 AOFM Annual Report 2007/08 – Role of the Commonwealth Government Securities Market, p.31 & p. 116.

The AER considers it reasonable to maintain its position that indexed CGS yields are not set in a well functioning market and do not reflect informed market opinion or future expectations of inflation. Therefore, the AER maintains the view of its previous determinations that the break even inflation rate, calculated as the difference between the yields on nominal and indexed CGS, will not provide a reliable or best estimate of inflation.

In January 2009, CEG stated that the global financial crisis has caused a ‘flight to safety’, resulting in such a high liquidity premium being paid for nominal CGS that, in the current market, exceeds the ‘peace of mind’ premium being paid for indexed CGS for inflation protection. CEG stated that if the AER’s approach to inflation estimates is applied in these circumstances then it will make the estimate of the real risk-free rate less accurate and not more accurate.[216]

The AER notes that the real risk-free rate return derived using the AER’s inflation estimate will always differ from observed yields on indexed CGS because the break even inflation rate relies on the use of indexed CGS yields. As noted above, indexed CGS yields are not set in a well functioning market, which means that they do not reflect informed market opinion or an efficient outcome, and should therefore not be relied upon for deriving future inflation expectations or a real risk-free rate. The AER considers that CEG’s conclusion on the relative movements of nominal and indexed CGS yields in the current market is unreasonable because any such conclusion will be tainted with the inefficiencies in the indexed CGS market.

The AER considers that CEG's suggested approach to use the break even inflation methodology where it is less than the RBA based inflation forecast[217] does not accord with the requirement under clause 6A.5.3(b) of the NER to apply the methodology that will result in the best estimate of expected inflation. Further, the AER has determined that the risk-free rate averaging period and the nominal risk-free rate that it has adopted is reasonable and the inconsistencies referred to by CEG are not valid due to inefficiencies in the indexed CGS market. Therefore, it is unnecessary to consider CEG's recommended solutions to the inconsistencies allegedly caused by using the risk-free rate averaging period that the AER has adopted.

In estimating forecast inflation, the AER is guided by the NER requirement that the appropriate approach to forecasting inflation should be a methodology that the AER determines is likely to result in the best estimate of expected inflation.[218] In the absence of a credible market-based inflation forecasting methodology, the AER considers that the methodology adopted in the draft decision and recent AER determinations[219] remain appropriate for the purpose of determining the best estimate of expected inflation for this final decision—that is, adopting an average inflation forecast based on the RBA’s short-term inflation forecasts and mid-point target inflation band.

[216] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 42

[217] ibid., pp. 46, 65.

[218] NER, clause 6A.5.3(b)(1).

[219] AER, *ElectraNet transmission determination 2008–09 to 2012–13: Final decision*, 11 April 2008, p. 69. See also AER, *SP AusNet transmission determination 2008–09 to 2013–14: Final decision*, January 2008, p.99–106.

The AER recognises that inflation forecasts can change in line with market sensitive data. The recent change in short–term inflation expectations has been evident in the past six months, as demonstrated by the RBA's stance on monetary policy. In the draft decision the AER stated it would update the inflation forecast for its final decision. This is consistent with regulatory practice in Australia.

The AER has updated the inflation forecast for the first two years of the next regulatory control period using the latest published RBA inflation expectations as shown in table 5.5.[220] In its revised regulatory proposal, ActewAGL proposed that a geometric average instead of a simple average be used as it provides a more accurate approach to determining the average 10–year inflation forecast.[221] The AER recognises there is considerable uncertainty in forecasting inflation. Having assessed ActewAGL's proposal, the AER agrees that a geometric average may provide for a more accurate estimate of expected inflation during the forecast period. The AER also notes that the difference between applying a simple and geometric average is marginal. For consistency with the ACT distribution determination, the AER has applied a geometric average for the Transend transmission determination.

The AER considers that, consistent with its draft decision methodology and based on a geometric average, an inflation forecast of 2.47 per cent per annum produces the best estimate for a 10-year period to be applied in the post–tax revenue model for this final decision.

Table 5.5: 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	Geometric Average
Forecast inflation	2.75	2.00	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.50	2.47

Source: RBA, *Statement on monetary policy*, 6 February 2009, p. 65.

5.6 AER conclusion

The AER has determined a nominal vanilla WACC of 8.80 per cent for Transend, based on the updated risk free rate and debt risk premium, and other parameters prescribed under chapter 6A of the NER. Table 5.6 sets out the WACC parameter values for this final decision and provides a comparison with the WACC submitted in Transend's revised revenue proposal. The AER's WACC is lower than Transend's revised proposal WACC because of a lower nominal risk free rate estimate—commensurate with monetary policy and softening in economic growth—adopted for this final decision.

The AER considers that its decision to withhold agreement to the averaging period in Transend's revenue proposal was reasonable and that the agreed averaging period is consistent with finance theory, regulatory practice, the NER and NEL. The AER considers that the material provided by Transend in support of its revised revenue proposal does not reasonably justify that an averaging period prior to December 2008

220 RBA, *Statement of Monetary Policy*, 6 February 2009, p. 65.
221 ActewAGL, *Revised regulatory proposal*, January 2009, p. 49.

is better than a period that is as close as practically possible to the start of the next regulatory control period.

The AER considers that only Bloomberg data should be used to estimate the debt risk premium based on its analysis of the fair yields reported by Bloomberg and CBASpectrum, observed yields of BBB+ corporate bonds and the methodologies adopted by these two data providers.

The AER maintains its draft decision to apply a methodology to determine a forecast inflation rate over a 10-year period using the RBA's inflation forecasts for the first two years and the mid-point of the RBA's target inflation range for the remaining eight years. The AER considers that, based on a geometric average, an inflation forecast of 2.47 per cent per annum produces the best estimate of a 10-year inflation forecast to be applied in the PTRM for this final decision.

Table 5.6: AER's decision on WACC parameters

Parameter	Transend's revised proposal	AER Conclusion
Risk–free rate (nominal)	4.66%	4.30%
Risk–free rate (real)		1.78%
Expected inflation rate	1.94%	2.47%
Debt risk premium	3.86%	3.49%
Market risk premium	6.00%	6.00%
Gearing	60%	60%
Equity beta	1	1
Nominal pre–tax return on debt		7.79%
Nominal post–tax return on equity		10.30%
Nominal vanilla WACC	9.38%	8.80%

6 Operating and maintenance expenditure

6.1 Introduction

This chapter sets out the AER's consideration of forecast operating and maintenance expenditure (opex) issues raised in response to the draft decision, including matters raised in Transend's January 2009 revised revenue proposal (revised revenue proposal).

The chapter is set out as follows:

- section 6.2 sets out relevant details of the regulatory framework
- section 6.3 reviews the AER's draft decision
- section 6.4 outlines Transend's revised revenue proposal
- section 6.5 summarises the submissions by interested parties on the AER's draft decision
- section 6.6 sets out and explains the AER's final decision.
- section 6.7 sets out the AER's conclusion.

6.2 Regulatory Framework

6.2.1 Opex objectives

Clause 6A.6.6(a) of the NER provides that a transmission network service provider (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:

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

6.2.2 Opex criteria and factors

Clause 6A.6.6(c) 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:

- the efficient costs of achieving the operating expenditure objectives;

- the costs that a prudent operator in the circumstances of the relevant TNSP would require to achieve the operating expenditure objectives; and
- 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 6A6.6(e):

- the information included in or accompanying the revenue proposal;
- submissions received in the course of consulting on the revenue proposal;
- 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);
- benchmark operating expenditure that would be incurred by an efficient TNSP over the regulatory control period;
- the actual and expected operating expenditure of the TNSP during any preceding regulatory control periods;
- the relative prices of operating and capital inputs;
- the substitution possibilities between operating and capital expenditure;
- 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;
- 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
- 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 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 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.

6.3 AER draft decision

In the draft decision the AER rejected Transend's forecast opex requirement of $280 million ($2008–09) and explained the reasons in respect of the proposal not meeting the opex criteria under clause 6A.6.6(c) of the NER.

The AER substituted a forecast opex requirement of $260 million which represented the total opex costs that a prudent operator in the circumstances of Transend would require to achieve the opex objectives.

Table 6.1 compares the opex allowance in the AER's draft decision with Transend's opex application.

Table 6.1: AER's draft opex decision

	2008–09	2009–10	2010–11	2011–12	2012–13	5 years Total
Transend's proposed controllable opex	**45.9**	**48.0**	**50.6**	**54.0**	**55.0**	**253.4**
Adjustment to field maintenance and operations	–0.1	–0.2	–0.2	–0.3	–0.5	–1.2
Adjustment to transmissions services	–0.2	–0.2	–0.3	–0.4	–0.5	–1.6
Adjustment to transmission operations	–0.1	–0.2	–0.2	–0.2	–0.3	–1.1
Adjustment to asset manager	–0.2	–0.2	–0.3	–0.4	–0.5	–1.5
Adjustment to corporate	–0.2	–0.2	–0.2	–0.3	–0.5	–1.5
AER's adjusted controllable opex	**–0.8**	**–1.0**	**–1.1**	**–1.6**	**–2.3**	**–6.8**
Transend proposed uncontrollable opex	**8.0**	**6.9**	**4.3**	**4.4**	**4.4**	**28.1**
Adjustment to debt raising costs	–0.4	–0.4	–0.5	–0.5	–0.6	–2.4
Adjustment to equity raising costs	–2.4	–2.4	–2.4	–2.4	–2.4	–12.1
AER's adjusted uncontrollable opex	**–2.8**	**–2.8**	**–2.9**	**–2.9**	**–2.9**	**–14.4**
Total AER adjustments	**–3.6**	**–3.8**	**–4.0**	**–4.5**	**–5.3**	**–21.2**
Total allowable opex	**50.3**	**51.0**	**50.9**	**53.8**	**54.2**	**260.2**

Explanation of the approach taken in the draft decision

The detail of the approach taken in the draft decision is set out in that document. The key points are as follows:

- In Transend's initial revenue proposal, Transend suggested several escalators for labour, materials, and others for forecast opex. The AER rejected Transend's escalation rates because the data behind these claims were not sufficiently robust and constant economic growth was assumed at a time when economic conditions were deteriorating.

- The AER rejected both of the central arguments set out in Transend's revenue proposal regarding equity raising costs. The AER was not convinced by the arguments made by CEG to support Transend's claim nor the need for Transend to raise external equity.[222]

- The AER was not satisfied that there was a need to provide indirect debt raising costs under the regulatory framework, or that the AER's method for calculating the benchmark costs under–compensated regulated network service providers (NSPs). Accordingly, the AER maintained its approach of providing benchmark debt raising costs in accordance with the 2004 Allen Consulting Group (ACG) methodology[223] as applied in previous revenue determinations.[224]

6.4 Transend revised proposal

Broadly, Transend's revised revenue proposal covered the following matters:

- Debt and equity raising costs: Transend rejected the AER's conclusion regarding these costs and contracted CEG and Harding Katz to comment on these matters.

- Escalators: Transend largely accepted the AER's decision but rejected the notion that the AER should be allowed to review these escalators once the draft decision had been made.

- Telecommunication costs: Transend's revised revenue proposal included an amendment to telecommunication costs due to the acquisition of telecommunication services business from Hydro Tasmania.

The details of these issues are discussed below.

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222 AER, *Transend transmission determination for the regulatory control period 1 July 2009 to 30 June 2014: Draft decision*, 21 November 2008, pp 196-198.

223 Allen Consulting Group (ACG), *Debt and equity raising transaction costs: Final report to the ACCC*, December 2004.

224 AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12: Decision*, 14 June 2007, pp. 94–97; AER, *SP Ausnet transmission determination 2008–09 to 2013–14*: *Final decision*, January 2008, pp. 148–150; AER, *Electranet transmission determination 2008–09 to 2013–14: Final decision*, 11 April 2008, pp. 84–85.

6.5 Submissions

There were several responses to the AER's draft decision. The key points are summarised below.

Rio Tinto Alcan

Rio Tinto Alcan (RTA) raised the following points in its submission:

- Transend's consultant is incorrect in its assessment that the ACCC locked in Transend's RAB. Transend's RAB was locked in by the AEMC for the reasons outlined in its determination to chapter 6A of the NER.
- RTA supported the AER's draft decision in relation to debt and equity raising costs.[225]

Nyrstar

Nystar tendered a confidential submission that was supportive of the AER's position on the following:

- Escalators
- Debt raising costs and
- Equity raising costs.[226]

Major Employer Group Tasmania (MEG)

MEG provided a submission which raised the following issues:

- MEG concurred with the AER that debt raising costs ought to be reduced and equity raising costs disallowed.
- MEG rejected Transend's claims for labour cost escalation noting the effects of the global financial crisis on the unemployment rate and Transend's claim that it is operating in a tight market for skilled labour.
- MEG recommended the AER reject Transend's claim for additional operating expenditure.[227]

Energy Users Association (EUAA)

The main points raised by the EUAA in its submission were as follows:

- There is evidence that a number of the opex drivers are weakening as a result of the global financial crisis and downturn in the Australian economy. Therefore, in these conditions, Transend, like other business should aim to reduce costs.

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225 Rio Tinto Alcan, *Transend revenue cap 2009/10-2013/14 submission by Rio Tinto Alcan (Bell Bay) in response to the draft decision of the AER*, February 2007.

226 Nystar, *Submission to Transend's revised revenue proposal*, February 2007

227 Major Employer Group, *Submission to AER on the Transend transmission revised revenue proposal*, February 2008.

- The EUAA was critical of the examination conducted by WorleyParsons.
- The AER's review of Transend's expenditure in the current regulation period to determine the efficient base year expenditure does not have sufficient evidence. The AER has a duty under the Rules to justify its conclusions and cannot draw such conclusions based on a lack of evidence to the contrary.[228]

Powerlink

Powerlink submitted that the Econtech labour cost forecasts adopted by the AER tend to be lower than those put forward by CEG, and materially so in the case of general wages. Powerlink recommended the AER consult more widely on escalators prior to finalising its review.[229]

6.6 AER considerations

This subsection sets out the AER's considerations relevant to its determination on opex, and describes and explains the reasons for the differences from the draft decision.

The approach to determining the opex allowance

The AER has decided to adopt the approach set out in the draft decision in setting an opex allowance for Transend.

6.6.1 Efficient base year

Subject to some adjustments which are outlined in this final decision, the AER considers that Transend's operating expenditure for 2006/07 is an appropriate representation of Transend's underlying opex costs. WorleyParsons also used these costs as the basis of its examination of Transend's operations.

In response to the AER's draft decision, the EUAA stated that there was insufficient evidence in the draft decision to conclude that the 2006/07 year was an efficient base year for predicting opex in the forthcoming regulatory control period. The EUAA also noted that total controllable opex was 20 per cent higher than 2004/05. Further, the EUAA was of the opinion that the AER should quantify and explain the permanent changes to Transend's operations as a result of NEM entry. Finally, the EUAA considered that the AER should utilise benchmarking to test Transend's efficiency.

Relationship between rising costs and efficiency under the NER

The AER noted that Transend's actual opex for the year ending June 2007 was higher than previous years. In the draft decision, the AER accepted that these cost increases were reasonable given the costs escalations faced by Transend at the time. The AER has verified these escalators[230] and is satisfied that they meet the opex objectives.

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[228] Energy Users Association, *Submission to AER on the draft decision on Transend's regulated revenue for the 2009 to 2014 regulatory period*, February 2009.

[229] Powerlink, *Draft decision Transend transmission determination 2009 to 2013-14*, February 2009.

[230] Transend Networks PTY LTD, *Enterprise agreement 2006, KPMG, Supplier arrangements, Review of commercial relationship between Transend Networks Pty Ltd and Aurora Energy Pty*

A key concern of the EUAA was that there may be a positive relationship between rising costs and inefficiency. The AER considers this to be a narrow interpretation of the NER in that it has disregarded all other factors in the opex objectives:

- to meet the expected demand for prescribed transmission services over that period
- to comply with all applicable regulatory obligations associated with the provision of prescribed transmission services
- to maintain the quality, reliability and security of supply of prescribed transmission services
- to maintain the reliability, safety and security of the transmission system through the supply of prescribed transmission services.

The AER has taken all these factors into account (including rising costs) in its assessment of efficiency.

Efficiency of Transend's operations

The EUAA stated that they considered the basis of WorleyParsons' investigation of maintenance practices to be inadequate. The AER does not agree. WorleyParsons has expertise in the power engineering field, made appropriate inquiries of the key Transend staff, examined and reviewed documented maintenance procedures[231] and physically inspected a randomly selected sample of Transend's assets. Although one site was noted prominently in its report, WorleyParsons was satisfied that detailed observations at this site were consistent with its observations of other Transend sites. The AER has also reviewed Transend's maintenance practices and agrees with WorleyParsons' view that these are prudent and efficient.

The EUAA stated that WorleyParsons' conclusion regarding the base year is not factually correct. The AER considers that the EUAA has not given due consideration to the analysis and reasoning informing WorleyParsons' conclusion. The AER rejects this claim noting that:

Ltd, June 2008. KPMG, *Supplier arrangements: Review of commercial relationship between Transend Networks Pty Ltd and Hydro Consulting Services*, June 2008, Transend-Aurora performance incentive scheme, May 2007, Tran/Aur-04-2004, 2004 and contract Tran/Aur-04-2004 Amendment Deed between Transend and Aurora 2006, Transend, Contract services definitions Hydro Tasmania 110kV and 120kV upgrade, 2006.

231 Transend Networks, *Circuit breaker preventive maintenance plan,* 2006-07, Transend Networks, *CB maintenance at Chapel Street substation*, Transend Networks, *Work practice assessment report*, Transend Networks, *Transmission line easement asset management plan*, Transend Networks, *Reyrolle Type 110/OS 110 kV circuit breaker condition assessment report*, Transend Networks, *Sprecher and Schuh HPF 110 kV circuit breaker condition assessment report*, Transend Networks, *Extra high voltage circuit breaker asset management plan*, Transend Networks, *EHV Circuit breakers – planned maintenance program*, KPMG, *Supplier arrangements: Review of commercial relationship between Transend Networks Pty Ltd and Aurora Energy Pty Ltd*, June 2008. KPMG, *Supplier arrangements: Review of commercial relationship between Transend Networks Pty Ltd and Hydro Consulting Services*, June 2008, Transend-Aurora, *Performance incentive scheme*, May 2007, Tran/Aur-04-2004, 2004 and contract Tran/Aur-04-2004, *Amendment deed between Transend and Aurora* 2006, Contract services definitions Hydro Tasmania 110kV and 120kV upgrade 2006.

- The current determination details the step changes in Transend's operations which accounts for the increases in Transend's opex in the current regulatory period.

- The AER investigated the cost pressures faced by Transend that led to the higher costs. This was detailed in the draft decision.

The full basis for WorleyParsons' conclusions, noting the analysis of each opex component and the reasons for its conclusions is as follows:

> - An examination of the audited Base-Year (2006/07)…… shows that in every case with the possible exception of "Substations" the Opex expenditure in the Base-Year was not exceptional, rather it was a conservative level of expenditure when compared to the two years before and after it;[232]
>
> - In the case of Substations, which employs zero-base forecasting, the relativity of the level of expenditure in the Base-Year to other years in the Current Regulatory Control Period was not relevant to the forecasting methodology; and
>
> - In view of the above, WorleyParsons considers that there was no indication to suggest that the Base-Year data was inappropriate for its use in the forecasting methodology, rather it appeared to be quite a conservative year from which to make forward projections.

Overall, WorleyParsons formed the view that Transend's maintenance practices, as demonstrated by the examples shown to WorleyParsons during the above mentioned physical inspections, were in accordance with best industry practice, and therefore "prudent".[233]

Staffing levels at Transend

The AER notes the EUAA's concerns regarding Transend's staffing levels. In the draft decision, the AER noted that a review of Transend's staffing levels produced nothing to suggest that any increases in staffing levels were either imprudent or inefficient. Furthermore, a review of employee numbers in isolation does not provide a true picture, as an increase in employee numbers does not necessarily result in higher operating costs, as external contractor costs may be reduced.

The AER found that Transend's staffing levels have only increased marginally.[234] The AER's investigation revealed that Transend has evolved over time from an organisation that initially relied heavily on out-sourcing of labour to perform key functions to a reliance on a mixture of in-house and out-sourced labour. A number of these arrangements were imposed on the formation of the business and were based on historical arrangements rather than business experience. WorleyParsons' investigations reviewed key out-sourcing contracts. WorleyParsons reported that the investigation had found that the key out-sourcing contracts had been re-negotiated as they expired in order to minimise or remove take-or-pay provisions and to move

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232 WorleyParsons is referring to categories of opex and not total opex.

233 WorleyParsons, *Review of the Transend Transmission Network revenue proposal 2009-2014 an independent review prepared for the Australian Energy Regulator,* November 2008, pg. 187-188.

234 *Transend's response to request for information No. s 217*, 28 August 2008, *Transend's response to request for information No. s 221, 228*, 17 September 2008, *Transend's resource matrix 2007 and 2008, Transend's response to request for information No. 245*, 25 September 2008.

labour rates to a more competitive basis. These decisions were predicated on internal assessments of whether certain functions were core business activities and whether out-sourced activities represented good value for money. The chosen base year is the first year for which audited data is available and captures both the effects of these contractual renegotiations and the effect of new costs that resulted from NEM entry. The AER notes that the data provided by the EUAA to substantiate its claims were obtained from Transend's annual financial reports. Using data from the annual financial reports is unreliable as the number of staff includes all people employed at Transend during the financial year, including part time workers and non-executive directors. It should be noted that Transend's staff numbers varied throughout the year so using publicised data, which includes non-full time staff, may distort the outcome.

Benchmarking and efficiency

In developing the draft decision the AER considered whether a high level benchmark exercise conducted on Transend's opex and capex would yield a benefit. As noted in chapter 4 for capex, a particular approach was used in relation to replacement expenditure and that was pursued. However, it was noted that past and present AER Annual Regulatory Reports for TNSPs have benchmarked Transend against other TNSPs, but found that due to the differences in Transend's asset base these studies yielded little or no direct benefit. Nevertheless, the AER has, for the purpose of this final decision, included a benchmarking exercise to demonstrate why benchmarking is problematic in the case of Transend.

When combined with the benchmarking analysis conducted by WorleyParsons,[235] Transend's expenditure levels are similar to other TNSPs, especially with regards to opex. In capex Transend's performance is higher than other TNSPs but it was noted that it would be difficult to assess Transend against other TNSPs due to the differing composition of its assets base relative to its peers.

Given that this is the case, the AER considers that the capex ratios do little to assist in assessing relative efficiencies between TNSPs. The position of Transend relative to the other TNSPs is summarised in table 6.2:

Table 6.2: Transend's benchmarking results

Indicator	Relative position
Network length/peak load	Close to top of the range
Number of substations/peak load	Close to the bottom of the range
Capex as % of ave RAB	At the top of the range
Capex /km network length	Close to the top of the range
Capex /km network length (time series)	In the middle of the range
Capex/substations	In the middle of the range
Capex/energy transmitted	At the top of the range
Capex per substation as a function of load	At the top of the range

235 WorleyParsons, *Review of the Transend Transmission network revenue proposal*, op. cit. pp. 146-152 and 214-224.

density	
Opex as % of ave RAB	At the top of the range
Opex/km of network length	In the middle of the range
Opex/substations	Close to the bottom of the range

The full analysis is shown in appendix D.

Regarding the usefulness of the ITOMS information provided by Transend, the AER also noted the limitation and the weakness of this information (see appendix D for more details). Although the ITOMS data does indicate a time series of Transend's performance over time, the AER consider that its performance relative to its peers should not be relied upon, especially as the nature of the business was different to its peers and its circumstances had changed materially following NEM entry. The ITOMS data therefore had no weighting into the AER's decision making process regarding the efficient base year.

Due to the limitation in benchmarking, the AER extensively reviewed Transend's costs structures by testing the validity and reliability of the information provided by:

- reviewing Transend's external contracts
- reviewing invoices, internal budget papers, business cases and financial models
- reviewing internal processes and documentations for business practices.

As stated in the draft decision, the AER's review was focused on testing the validity of these expenditures which included analysing whether the base year contained non-recurrent expenditures. While the AER acknowledges that it is difficult in a review of this form to confirm whether these expenditures are efficient, the AER has seen no evidence to suggest that the over expenditures do not reflect prudent decisions.

However, the AER notes that the efficiency benefits sharing scheme aims to induce efficiency by providing continuous incentives over time, to reward efficiency and penalise inefficiency, to focus on controllable costs and to ensure inappropriate capitalisation is avoided. By penalising inefficiency and rewarding efficiency, the incentive regime encourages service providers to reveal their efficient or 'true' costs. Over time these savings will be passed onto consumers via lower prices.

6.6.2 Telecommunication costs

The AER's draft decision noted that Transend was in commercial negotiations with its operational telecommunications service provider to procure the telecommunications business, and that the AER would review these costs in the final decision.

Transend subsequently acquired the telecommunication business as a going concern in November 2008.

In its revised revenue proposal Transend indicated that:

> “the principal rationale for amending the forecast telecommunication costs is that the original Transend forecast was based on the existing contract terms and conditions at the time and, accordingly, did not allow for any escalation in labour costs. The forecast was therefore inconsistent with other operating expenditure categories, which properly included labour escalation rates. As a result of proper application of these labour escalators, Transend’s telecommunications costs, which are included in the field operations and maintenance expenditure category, are forecast to increase by approximately $1.4 million (real 2008–09 dollars) over the forthcoming regulatory control period”.[236]

The AER was of the view that all telecommunication costs (not just labour escalation) should be assessed against the opex objectives and contracted Nuttall Consulting to review and assess Transend’s claims.

Consultant review

Nuttall Consulting examined Transend’s telecommunication costs and considered them to be efficient. Nuttall Consulting also recommended that the AER make three adjustments to Transend’s telecommunication costs:

- an adjustment to licensing fees resulting from an incorrect allocation of overhead costs and
- an adjustment to internal margins resulting from a misallocation of administrative expenses
- an efficiency reduction.

AER considerations

The AER considers that the telecommunication costs submitted by Transend meet the opex objectives. The AER considers that telecommunications are critical to the provision of reliable and secure transmission services and that it was more beneficial for Transend to operate these services in conjunction with its transmission operations.

The AER noted that Nuttall Consulting had indicated that:

> It would be reasonable to assume that the majority of the efficiency opportunities could be achieved by the commencement or early into the next regulatory control period”.[237]

The AER agrees with Nuttall Consulting on the misallocation of licensing fees, administrative costs, and efficiency reduction and has adjusted Transend’s opex accordingly (see table 6.3). As discussed below the AER also rejects Transend’s labour escalation rate and has substituted its own values.

[236] Transend, *Revised revenue proposal for the period 1 July 2009 to 30 June 2014*, January 2009, p.61.

[237] Nuttall Consulting, *Review of Transend’s revised proposal*, March 2009, p.63.

Table 6.3: Telecommunication costs

Operational Telecommunications (OT)	*2006-07*	*2007-08*	*2008-09*	*2009-10*	*2010-11*	*2011-12*	*2012-13*	*2013-14*
Labour allocation	0.00	0.00	0.00	-0.01	-0.02	-0.03	-0.03	-0.04
Administrative overhead	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
Efficiency reduction	0.00	0.00	0.00	-0.02	-0.02	-0.04	-0.04	-0.04
Recommended OT	**-0.01**	**-0.01**	**-0.01**	**-0.04**	**-0.05**	**-0.08**	**-0.08**	**-0.09**

*excludes labour escalation.

6.6.3 Electricity, gas and water and general labour escalators

AER draft decision

The AER engaged Econtech to provide advice on labour cost growth forecasts in Tasmania. The AER was satisfied that Econtech's wage growth forecasts for the electricity, gas and water (EGW) sector were robust and applied these forecasts for the next regulatory control period. In applying Econtech's forecasts, the AER did not accept Transend's proposal, which was based on advice from the Competition Economists Group (CEG), to apply an average of Econtech (published in 2007) and Macromonitor EGW labour growth forecasts.[238]

Revised revenue proposal

Transend did not accept the EGW labour escalators applied by the AER in its draft decision. Transend re-engaged CEG to review the draft decision. CEG considered that while the AER's approach was largely reasonable, it had concerns with the timing calculations applied in the draft decision. Specifically:

- Econtech's forecasts for EGW wages growth were in financial year average terms, and not in June to June terms
- the EBA rate was not correctly timed to interpolate to EGW rates, resulting in the model double counting inflation for some years.

As a result, CEG proposed revised EGW wages labour escalators, based on the Econtech forecasts applied by the AER in its draft decision, to address these concerns.

CEG raised issues with the application of updated EGW labour escalators after Transend lodged its revised revenue proposal. CEG considered that if the AER was to seek an update from Econtech for EGW labour cost growth rates, it would be described as re-doing a forecast, rather than updating a forecast in accordance with an agreed methodology.[239]

Transend based on advice from CEG, considered that if the AER re-engaged Econtech to update its forecasts, then the AER should also undertake further consultation with Transend.[240]

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[238] AER, *Transend transmission determination 2008–09 to 2013–14: draft decision,* 21 November 2008, p. 176.

[239] CEG, *Escalators affecting expenditure forecasts: A report for NSW and Tasmanian electricity businesses*, p. 13.

[240] CEG, *Escalators affecting expenditure forecasts*, op. cit. p.14.

Transend stated in its revised revenue proposal that its EBA provides for individual employee increments and performance payments and that it should be able to recover these costs via an increase in its opex allowance. [241]

Submissions

The EUAA stated that due to the worsening economic climate, wage cost pressures had fallen. Further the EUAA noted: [242]

- the RBA had revised its Wage Price Index from 4 per cent in 2008–09 to 3.5 per cent in 2009–10
- the RBA expects the Wage Price Index to remain static at 4 per cent for 2010–11 to 2011–12.

The EUAA also submitted:[243]

- that the AER should refresh its labour cost escalation assumptions in light of the recent economic collapse and global downturn
- expected real wage increases should ultimately be discounted for normal increases in labour productivity
- that the past commodity boom and labour shortages are no longer realistic assumptions for the next regulatory control period
- cost escalation factors and labour costs be reviewed and updated for the changed economic circumstances that have resulted in the past 12 months since Transend's capex planning assumptions were developed.

Powerlink noted the AER's adoption of Econtech's labour forecasts and considered it reasonable for the AER to consult more widely on the escalators prior to finalising its determination.[244]

The Major Employer Group (MEG) submitted that Transend's claim that it continues to operate in a tight market for skilled labour contradicts the current economic environment in which unemployment is expected to rise substantially over the next 12 months.

Nyrstar provided a confidential submission to the AER with respect to Transend's revised revenue proposal.[245]

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241 Transend, *Revised revenue proposal*, op. cit. p.33.

242 EUAA, *Submission to Australian Energy Regulator's draft decision & revised DNSP proposals – Review of the regulatory proposals by the NSW electricity distributors*, p.18.

243 EUAA, *Submission to AER on the draft decision on Transend's regulated revenue for the 2009 to 2014 regulatory period*, pp. 13&17.

244 Powerlink, *Submission on Transend draft decision.* 18 February 2009, p. 2.

245 Nystar Australia Pty Ltd, *Submission to Transend's revised revenue proposa*l (confidential), 17 February 2009.

Consultant review

Econtech

The AER engaged Econtech to provide an update on its wage forecasts for the EGW sector in Tasmania. In preparing its labour costs growth forecasts, Econtech took account of the latest available wage data.

Econtech's updated forecasts for labour cost growth rates in the EGW sector across Tasmania for the next regulatory control period is shown in table 6.4 and outlined in further detail in appendix A of this final decision.

Table 6.4: Econtech's real labour escalation rates for the EGW sector in Tasmania and Australia (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Tasmania	-2.9	-0.8	2.4	2.7	1.3	0.6	-0.3
Australia	-0.7	-1.0	2.8	3.1	2.1	1.5	0.5

Source: Econtech, *Updated labour cost growth forecasts*, 25 March 2009, pp 29, 31.

AER considerations

Updated labour cost escalators

The details of the AER's assessment of the labour cost growth forecasts proposed by Transend are set out in appendix A of this final decision.

The AER notes submissions relating to labour cost escalators discussed changing economic conditions and that the labour cost escalators applied in the draft decision are now out of date. The AER engaged Econtech to provide updated labour cost escalators based on the most recent available data.[246] The AER considers that the updated forecasts take account of the current economic slowdown.

The AER acknowledges Transend's concerns regarding the sole reliance on one economic forecaster for its labour growth cost forecasts. In the draft decision, the AER did not consider the averaging methodology adopted by CEG was appropriate because the Macromonitor and Econtech EGW labour cost growth forecasts were not comparable and averaging the two forecasts was likely to produce unreliable labour cost escalation forecasts.[247] For this final decision, the AER maintains its view that it is not satisfied that Macromonitor provide sufficient explanation surrounding the basis of the model used to derive its forecasts. The AER also notes that Econtech found that upon reviewing CEG's revised escalator report, that it remained difficult to assess the forecast results provided by Macromonitor as no new information pertaining to the methodology have been provided.[248] The AER is satisfied that Econtech's

[246] New forecasts incorporate data published by the Australian Bureau of Statistics, including Average Weekly Earnings (released 26 February 2009) and National Accounts (released 9 March 2009).

[247] AER, *Transend draft decision,* op. cit pp. 361-362.

[248] Econtech, *Updated labour cost growth forecasts*, op. cit. p. 21.

methodology for forecasting labour costs growth is robust given the application of both an economic-wide model and a purpose-built labour cost model.[249]

The AER considers that CEG's recommendations regarding the appropriate timing of the escalators the AER applied in the draft decision are reasonable. The AER has implemented CEG's recommendations to Transend's labour escalators by making refinements to its cost escalations model to ensure the EBA rates are appropriately timed with forecast EGW rates to alleviate issues of double counting CPI. The AER has addressed this by creating an index of real wage rates, as recommended by CEG.

The AER has identified an error in CEG's model which mistime the application of Econtech's EGW wage rates by applying a financial year's data to a calendar year—this effectively means that CEG has been using Econtech's labour rates six months before the period in which they should be applied. The AER has corrected this error as part of the adjustments made for the appropriate timing of escalators in its model.

The AER notes that Transend, based on advice received from CEG, accepted the use of Econtech's forecasts in the draft decision as reasonable, subject to the AER rectifying the specified timing issues.[250] The AER further notes Transend's concerns with Econtech updating its forecasts after Transend's revised revenue proposal was submitted. To ensure a robust and transparent process on the updating of labour wage growth forecasts, the AER engaged in a briefing with Transend, where Econtech provided an overview of its economic models used to derive the labour wage growth forecasts and the economic assumptions underlying its updated forecasts. The AER also outlined refinements to its cost escalations model from the draft decision.

Enterprise Bargaining Agreement

For this final decision, the AER has adopted actual wage data increases for 2007–08 provided for under Transend's EBA. Further, the AER has applied Transend's 2008–09 EBA rates to its EGW labour escalation. For the next regulatory control period, the AER has adopted Econtech's updated EGW labour cost growth forecasts. The AER does not consider it appropriate to use Transend's EBA rates for the next regulatory control period as this would move Transend from an incentive based framework to a cost of service recovery framework. This means Transend still has an incentive to negotiate with its employees to obtain productivity savings under its EBA.

EBA employee increments and performance payments

Transend has sought employee increments above the base EBA wages rate in its revised revenue proposal. The AER understands that these increments are:

- salary progression to individual staff (i.e. permanent increases in wage) based on the objective to appropriately position staff within a given salary band in a fair and equitable manner recognising skills, experience (competence) and performance.[251]
- part of a remuneration process for retaining staff

[249] Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, op. cit.

[250] CEG, *Escalators affecting expenditure forecasts*, pp. 7–12.

[251] Transend, *Transend Networks Pty Ltd: Enterprise agreement 2006*, 17 February 2006.

- only applied to select staff who outperform their key performance indicators.

The AER notes that Transend's EBA suggests the annual salary progression policy is used to allow 'performance payments' which are increases in pay based on productivity improvements by individual staff. The AER requested additional information on these issues but Transend was unable to demonstrate that these payments are made across the entire organisation.

The AER is not satisfied that Transend has demonstrated how individual performance bonuses paid to employees would result in higher productivity levels for the entire organisation, and therefore the need to allow the cost impact to Transend's opex. The AER also notes that Transend's EBA states that salary progression is not automatic under Transend's performance planning process.

The AER notes that performance bonuses generally reflect individual employee productivity improvements and as such are selective, rather than broad based payments.[252] Any bonus paid by Transend, provided it is less than the cost of employing new staff to increase output by the equivalent productivity increase, should result in cost savings for Transend.[253] Therefore, the AER is not satisfied that Transend has appropriately quantified the increase to its labour costs through its application of performance targets and individual productivity relative to increased productivity of Transend in its entirety.

The AER also notes that the only other NSP to apply for a similar productivity related rate above the EBA allowance is ActewAGL in its 2009–14 revenue proposal. ActewAGL sought to include performance amounts with the (base) EBA rate and this was rejected by the AER.

Under the current incentive framework, the AER approves a forecast allowance that a TNSP must spend as efficiently as possible. The AER considers that allowing cost escalation to include the performance targets would result in a move towards a cost of service model for labour cost. The AER notes that it is:

- only required to provide regulated businesses a reasonable opportunity to recover efficient costs
- not required to provide compensation for every decision made by a TNSP that impacts on its costs.

The AER considers that the use of Transend's negotiated EBA wage rate for 2007–08 to 2008–09 will provide a reasonable proxy of real wage cost increases across the organisation.[254] The AER considers that extending Transend's EBA to include individual employee performance payments (along with any other individual payments businesses may choose to allow its staff) will undermine the incentive framework for businesses to operate efficiently.

252 The AER notes Econtech's labour cost forecasts are adjusted for productivity growth which is applicable to all NSPs across their entire workforce. For further discussion, see: Econtech, *Updated labour cost growth forecasts*, pp. 20–26.

253 That is, while labour costs may increase, total costs per unit of output will decrease.

254 Following 2007–08 to 2008–09, EGW cost escalators will be applied for the next regulatory control period.

For the reasons discussed and as a result of the AER's analysis of the revised revenue proposal and the additional information provided, the AER is not satisfied that the application of employee increments and performance payments to Transend's EGW labour opex component results in expenditure which reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors.

Application of labour cost escalators

For this final decision, the AER adopted Econtech's updated wage growth forecasts for the next regulatory control period. It also re-modelled the forecasts to address CEG's timing issues and applied these updated forecasts for the EGW sector in Tasmania for the next regulatory control period. Actual wage data, however, was available for 2007–08 and 2008–09, and therefore the AER has applied actual wage increases for those years, which have also been remodelled to address the timing issues.

The EGW labour cost growth forecasts that the AER will apply to Transend's opex for the next regulatory control period are shown in table 6.5.

Table 6.5: AER's conclusion on Transend's real general labour escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Econtech/AER	-2.2	-1.9	0.0	0.5	-0.7	-1.0	-1.5

AER conclusion

As a result of the AER's analysis of the revised revenue proposal, the AER is satisfied that the application of updated EGW labour cost escalators for Tasmania (as set out in table 6.4), within Transend's opex model results in forecast opex reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors.

6.6.4 Asset growth factors

Transend used asset growth to escalate its base year expenditure. Forecast opex is escalated by the asset growth factors to take into account additional operational requirements resulting from asset developments on the transmission network. Escalation on materials costs and other non-labour escalators, which impacts capex and hence the asset growth factors, are discussed in chapter 4 and appendix A of this final decision.

Draft decision

The AER rejected Transend's assets growth factors due to the changes incorporated in the capex forecasts by the AER (including escalators used for materials, labour, and non-labour and the deferral of certain asset renewal projects). The revised asset growth values are shown in table 6.6, and are applied in the opex model to derive opex forecasts.

Table 6.6: AER draft decision — Asset growth factors (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Substations	0.1	8.0	2.5	5.1	0.5
Transmission Lines	0.0	7.6	2.2	1.4	0.0
Protection & Control	0.1	9.8	2.9	6.3	0.8
Easements	0.0	1.1	4.1	17.0	14.9
Total	**0.4**	**7.8**	**2.4**	**3.7**	**0.7**

Source: AER Draft decision p.179.

Transend's revised revenue proposal

Transend did not specifically address the asset growth factors in the revised revenue proposal. However the inputs and escalations behind the asset growth factors were rejected by Transend.

AER considerations

As noted in the draft decision, the asset growth factors used in the final decision must reflect the changes incorporated in the capex forecasts (including escalators used for materials, labour, and non-labour and the deferral of certain asset renewal projects). Given the changes indicated in chapter 4 and appendix A, the revised asset growth values are shown in table 6.7 and are applied in the opex model to derive the opex forecasts.

Table 6.7: AER conclusion — Asset growth factors (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Substations	0.6	7.8	2.5	5.0	0.5
Transmission Lines	0.0	7.5	2.2	1.4	0.0
Protection & Control	0.9	9.6	2.9	6.2	0.8
Easements	0.0	1.0	3.9	16.8	14.8
Total	**0.7**	**7.7**	**2.4**	**3.7**	**0.7**

6.6.5 Debt raising costs

Debt raising costs are incurred each time debt is rolled over, and may include underwriting fees, legal fees, company credit rating fees and other transaction costs. The AER has accepted that debt raising costs are a legitimate expense for which a TNSP should be provided an allowance.[255]

AER draft decision

In the draft decision, the AER did not accept Transend's proposal to include in its opex forecast a benchmark allowance for debt raising costs equal to 0.155 per cent

255 AER, *Decision: Powerlink 2007–08 to 2011–12*, pp. 94–97; AER, *Final decision: SP AusNet 2008–09 to 2013–14*, pp. 148–150; AER, *Final decision: Electranet 2008–09 to 2013–14*, pp. 84–85.

(15.5 basis points) of the benchmark debt share (60 per cent) of the opening regulatory asset base (RAB) in each year of the next regulatory control period.

The AER was not satisfied that there was a need to provide indirect debt raising costs under the regulatory framework, or that the AER's method for calculating the benchmark costs under–compensated regulated network service providers (NSPs).

Accordingly, the AER maintained its approach of providing benchmark debt raising costs in accordance with the 2004 Allen Consulting Group (ACG) methodology[256] as applied in previous revenue determinations.[257] This methodology involves the calculation of the cost of a benchmark bond issue (size $200 million), and the number of such bond issues required to rollover the benchmark debt share (60 per cent) of the RAB. The allowance for the benchmark bond issue is based on the direct costs of raising debt, such as underwriting fees, legal fees and credit rating fees.

Applying the ACG methodology to Transend, the AER approved an allowance of 8.7 bppa over a notional debt component of the RAB in each year, resulting in a total allowance of $3.0 million ($2008–09) over the next regulatory control period.[258]

Transend's revised revenue proposal

Transend did not accept the draft decision on debt and equity raising costs. In support of its revised revenue proposal, Transend restated arguments from the CEG report provided in its May 2008 revenue proposal[259]and submitted a second CEG report.[260] In substance, these consultant reports are common to multiple revised revenue and regulatory proposals. Specifically, Transend, TransGrid and the four NSW/ACT DNSPs have all relied on essentially the same CEG report[261] as the core of their arguments on this matter.

On the basis of the recommendations of its consultants' reports, Transend proposed an allowance of 15.5 basis points per annum (bppa) based on the notional debt component of RAB for each year of the next regulatory control period. This resulted in a total proposed allowance of $5.4 million ($2008–09).

Table 6.8 provides the AER's draft decision and Transend's revised revenue proposal on debt raising costs.

256 Allen Consulting Group (ACG), *Debt and equity raising transaction costs: final report to the ACCC*, December 2004.

257 AER, *Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12: Decision*, 14 June 2007, pp. 94–97; *AER, SP Ausnet transmission determination 2008–09 to 2013–14: Final decision*, January 2008, pp. 148–150; AER, *Electranet transmission determination 2008–09 to 2013–14: Final decision*, 11 April 2008, pp. 84–85.

258 AER, *Transend draft decision*, op. cit p. 192

259 CEG, *Nominal risk free rate, debt risk premium and debt and equity raising costs*, Appendix to Transend Revenue Proposal, 31 May 2008.

260 CEG, *Debt and equity raising costs: Appendix to Transend revised revenue proposal*, 14 January 2009

261 ibid.

Table 6.8: Draft decision and Transend's revised revenue proposal positions on debt raising costs ($m, 2008–09 real)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER's draft decision	0.5	0.6	0.6	0.7	0.7	3.0
Transend's revised revenue proposal	0.9	1.0	1.1	1.2	1.2	5.4

Source: Transend, *Revised revenue proposal*, p. 62.

Submissions

Nyrstar and the Major Employers Group (MEG) submitted support for the AER's draft decision on debt raising costs. Rio Tinto Alcan (RTA) Bay Bell submitted that if Transend is not willing to allow the AER to publish its further submission on debt and equity raising costs (due to confidentiality issues) in sufficient time to give affected parties a reasonable opportunity to respond, the AER should, pursuant to clause 6A.16(e), give these further arguments no weight in its transmission determination and affirm its draft decision in relation to these issues.

Powerlink submitted that the AER should reconsider its position on the acceptance of direct and indirect debt raising costs for Transend in light of the compelling evidence presented by CEG.[262]

Consultant review

The AER engaged Dr John C. Handley, Associate Professor in Finance at the University of Melbourne, to review the submitted material on this issue, including the revenue proposal and revised revenue proposal submitted by Transend, and all relevant accompanying consultant reports.[263]

In his report, Associate Professor Handley segregated debt raising costs into two key areas: indirect (underpricing) and direct. On the underpricing of debt capital, he stated:

> The key issue is whether the AER's approach to estimating the cost of debt for the regulated firm is appropriate. If it is then, by definition, no compensation for underpricing is necessary, otherwise double counting would arise.[264]

Associate Professor Handley then reviewed the methodology adopted by the AER, noted CEG's review of this methodology and specifically considered the Cai, Helwege and Warga (2007) paper that found no evidence of underpricing on investment grade bond offerings. He concluded:

> In summary, assuming allowed revenues are determined using an appropriate estimate of the cost of debt (and noting that both the AER and CEG believe

262 Powerlink, *Letter regarding the draft decision Transend Transmission Determination 2009-10 to 2013-14*, 16 February 2009.

263 Handley, J. C. *A Note on the costs of raising debt and equity capital: Report prepared for the Australian Energy Regulator*, 12 April 2009. Associate Professor Handley is a leading academic on cost of capital issues and has been advising the AER as part of its 2009 WACC review.

264 Handley, op. cit. p. 15–16.

> this to be the case), then it is my view that, underpricing should not be allowed as a cost of raising debt capital.[265]

On the direct costs of raising debt capital, Associate Professor Handley noted the debate regarding the measurement of direct costs, amortization and inflation. Where relevant, detailed comments drawn from his review are included in the AER considerations and set out in appendix E of this final decision.

AER considerations

The AER's detailed considerations of Transend's proposed debt raising costs are presented in appendix E 'AER considerations of proposed debt and equity raising costs'. The AER notes that the consultancy reports submitted by Transend on these matters are also applicable to the AER's considerations concerning TransGrid's revenue proposal and the regulatory proposals of ActewAGL, Country Energy, EnergyAustralia and Integral Energy. The AER considers that its approach should be consistent across each of these businesses. Accordingly, appendix E is a generic that is applicable to the AER's decisions for Transend, TransGrid, and the ACT/NSW DNSPs.

In summary, the AER considers that the proposed allowance for indirect debt raising costs is inconsistent with the regulatory framework. If indirect costs were actually incurred in practice,[266] the AER expects that such costs would already be taken into account through estimates of the cost of debt. This view was supported by the AER's consultant on this matter, Associate Professor Handley.[267]

Regarding the appropriate benchmark for direct debt raising costs, the AER considers that the amount applied in the draft decision—based on the ACG approach—is appropriate.[268] The AER considers that the ACG approach is more likely to provide the best estimate of direct debt raising costs to be incurred by the benchmark regulated business than the methodologies proposed by the network service providers and their consultants. Among other reasons, this is largely because the ACG approach is based on market observations of Australian firms raising capital, rather than foreign firms in foreign markets.

Table 6.9 shows the updated build up of debt raising costs and the total benchmark for various bond issues, based on the ACG's methodology.

Table 6.9: Benchmark debt raising costs for corporate bond issues (bppa)

Fee	Explanation/source	1 issue	2 issues	3 issues
Amount raised	Multiples of median bond issue size	$200m	$400m	$600m
Gross underwriting fees	Bloomberg for Australian internal issues, term adjusted	6.0	6.0	6.0

265 Handley, op. cit. p. 17.
266 The AER considers that there is no reliable empirical evidence that indirect debt raising costs exist.
267 Handley, op. cit. pp.14–17.
268 AER, *Transend draft decision*, op. cit. p. 192

Legal and roadshow	$75k–$100k: industry sources	1.0	1.0	1.0
Company credit rating	$30k–$50k (once off): S&P ratings	2.5	1.3	0.8
Issue credit rating	3.5 (2.5) basis points up front: S&P ratings	0.7	0.7	0.7
Registry fees	$3k/issue: Osborne Associates	0.2	0.2	0.2
Paying fees[a]	$1/$1m quarterly: Osborne Associates	0.0	0.0	0.0
Total	Basis points per annum	10.4	9.2	8.7

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 zero.

The AER maintains its gross underwriting fee and bond issue size benchmarks which were set out in the draft decision, and which were updated according to the ACG methodology.[269] Based on the ACG methodology, Transend will require around 3 bond issues over the next regulatory control period. As such, the AER considers that an allowance of 8.7 bppa for debt raising costs is a reasonable benchmark for Transend. Using the post–tax revenue model (PTRM), this benchmark is multiplied by the debt component of Transend's opening RAB to provide an average allowance of $0.6 million per annum ($2008–09).

The AER's conclusions on debt raising costs for Transend over the next regulatory control period are set out in table 6.10.

Table 6.10: AER's conclusion on debt raising costs ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Debt raising allowance	0.5	0.5	0.6	0.7	0.7	2.9

For the reasons discussed and as a result of the AER's analysis of Transend's revised revenue proposal and additional information, the AER is not satisfied that Transend's proposed debt raising cost allowance reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors. The AER considers the benchmark debt raising allowance set out in table 6.10 represents the efficient costs that a prudent operator in the circumstances of Transend would require to achieve the opex objectives in the next regulatory control period.

6.6.6 Equity raising costs

In raising new equity capital a business may incur costs such as legal fees, brokerage fees, marketing costs and other transactions costs. These are upfront expenses, with

269 AER, *Transend draft decision*, op. cit .pp. 191-192.

little or no ongoing costs over the life of the equity. Whilst the bulk of the equity a firm will raise is typically at its inception, there may be points in the life of a firm where it chooses external equity funding (instead of debt or internal funding) as a source of additional equity, and accordingly may incur equity raising costs.

The AER has accepted that equity raising costs are a legitimate expense for a benchmark firm only where external equity funding is the least–cost option available.[270] A TNSP should only be provided an allowance for equity raising costs where cheaper sources of funding—for example, retained earnings—are insufficient, subject to the gearing ratio and other assumptions about financing decisions being consistent with regulatory benchmarks.

AER draft decision

In the draft decision, the AER did not accept Transend's proposal for an opex allowance for equity raising costs equal of 7.6 per cent of the required equity, (based on the capex allowance) at a total cost of $12 million ($2008–09) over the next regulatory control period.

The AER rejected both of the central arguments set out in Transend's revenue proposal regarding equity raising costs. Firstly, the AER was not satisfied that there was a need to take account of the indirect costs of raising equity under the benchmark regulatory framework.[271] Citing a report by CEG, Transend argued that the indirect and direct costs of raising equity were linked (in a similar way to debt raising costs) and that the underpricing of equity was required to ensure the success of a capital raising. The AER was not convinced by these arguments, and applied the ACG (2004) methodology for calculation of direct equity raising costs only.[272]

Secondly, the AER was not satisfied that there was a need for Transend to raise external equity.[273] Transend contended that, as part of the cash flow analysis to determine external equity requirement, a dividend yield of 8.6 per cent should be applied. Based on its analysis, Transend submitted that it would need to raise new equity. By contrast, in reviewing Transend's revised revenue proposal the AER undertook a benchmark cash flow analysis, which adopted a 70 per cent dividend payout ratio instead of a dividend yield.[274] The AER's analysis indicated that Transend would be able to fund its capex program over the next regulatory control period with retained cash flows. Accordingly, the AER determined that Transend would not require additional equity finance in the next regulatory control period and therefore would also not require an allowance for equity raising costs.[275]

Transend revised revenue proposal

Transend did not accept the draft decision and argued on a number of grounds for the acceptance of its revenue proposal. In general, Transend claimed that the AER had not considered or had not given sufficient regard to the evidence put forward by Transend in relation to equity raising costs. Many of the issues and arguments raised

270 ACG, p. 12.
271 AER, *Transend draft decision*, op. cit. p. 195.
272 AER, *Transend draft decision*, op. cit. p. 195.
273 AER, *Transend draft decision*, op. cit. pp 196-198.
274 AER, *Transend draft decision*, op. cit. p. 198.
275 AER, *Transend draft decision*, op. cit. p. 198.

by Transend were based on a CEG report commissioned in conjunction with TransGrid and the four ACT and NSW DNSPs.[276]

Transend's revised revenue proposal rejected the 70 per cent dividend payout ratio assumed by the AER and adopted a 5.5 per cent dividend yield, on the grounds that the dividend yield which resulted was below the expected return on equity.[277] In support of its revised revenue proposal, Transend restated arguments from the original CEG report,[278] and submitted a second CEG report.[279] As with debt raising costs, most of these consultant reports were submitted by multiple service providers with their revised revenue and regulatory proposals.

On the basis of the recommendations of its consultants, Transend proposed an allowance of 7.6 per cent applied to the additional equity requirement. This resulted in a total proposed allowance of $11.4 million ($2008–09) over the next regulatory control period.[280] Table 6.11 provides the AER's draft decision and Transend's revised revenue proposal on equity raising costs.

Table 6.11: AER's draft decision and Transend's revised revenue proposal on equity raising costs ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER's draft decision	0	0	0	0	0	0
Transend's revised revenue proposal	2.3	2.3	2.3	2.3	2.3	11.4

Source: AER, *Transend draft decision*, p. 202. Transend, *Revised revenue proposal*, p. 62.

Submissions

Powerlink questioned whether the AER had given due and appropriate consideration to the evidence from CEG regarding the equity raising allowance for Transend.[281] Powerlink noted that the AER accepted the possible existence of underpricing for SEOs, yet did not allow compensation for this indirect cost. Powerlink did not consider that the AER had demonstrated theoretically or empirically why either compensation for indirect costs would be inconsistent with the benchmark WACC framework, or why efficient benchmark service providers should be able to raise capital without incurring underpricing costs.

Nyrstar and the Major Employers Group (MEG) submitted support for the AER's draft decision on equity raising costs.

276 CEG, *Debt and equity raising costs: Appendix to Transend revised revenue proposal*, January 2009.

277 Transend, *Revised revenue proposal*, op. cit. p.60.

278 CEG, *Nominal risk free rate, debt risk premium and debt and equity raising costs: Appendix to Transend revenue proposal*, 31 May 2008.

279 CEG, *Debt and equity raising costs: Appendix to Transend revised revenue proposal*, January 2009.

280 Transend, *Revised revenue proposal*, op. cit. p. 62.

281 Powerlink, *Submission in response to the AER's draft decision on Transend's 2009–10 to 2013–14 revenue cap*, 16 February 2009, pp. 2-3.

Consultant review

Associate Professor Handley was engaged by the AER to review the submitted material on this issue, including the revenue proposal and revised revenue proposal submitted by Transend, and all relevant accompanying consultant reports.

Associate Professor Handley considered the arguments made on the underpricing of equity capital, and noted that both CEG and Carlton relied upon the assumption that new shares were not sold to existing shareholders.[282] Associate Professor Handley viewed this assumption as unreasonable. He also considered it inappropriate to provide an allowance for underpricing costs associated with raising equity capital as they are inconsistent with the regulatory framework:

> …under the regulatory framework the appropriate return on (equity) capital is determined by the CAPM and therefore any allowance for underpricing costs would effectively amount to an increment being added to the CAPM - a position which could only be justified on policy rather than theoretical grounds.[283]

Associate Professor Handley considered the indirect costs of retained earnings, rights issues and dividend reinvestment plans, and concluded in each case that it was not appropriate to provide an allowance for such costs.[284]

Associate Professor Handley also considered the direct costs of raising equity capital, noting the different methods (placements, rights issues and dividend reinvestment plans) and the level of agreement on these direct costs. He advised that the reasonable range for direct equity raising costs is between 2 and 3 per cent of the amount raised.[285]

Finally, Associate Professor Handley considered the benchmark cash flow modelling applied to determine the equity requirement. He noted many of the assumptions were 'arbitrary in the sense that they are simply inputs into the modelling process,'[286] but stated:

> The key issue is to ensure that any assumptions made here are consistent with the overall regulatory framework.[287]

Associate Professor Handley analysed the concerns raised in relation to payment of debt principal for maintaining the assumed gearing ratio, and the payout of dividends in order to value imputation credits. In both cases, Associate Professor Handley noted that the NSPs' concerns were valid and that the AER should amend its benchmark cash flow analysis to take account of these concerns.[288]

AER considerations

The AER's detailed considerations of Transend's proposed equity raising costs are presented in appendix E. The AER notes that the consultancy reports submitted by

282 Handley, op. cit. p. 7.
283 Handley, op. cit. p. 11.
284 Handley, op. cit. pp. 4–14.
285 Handley, op. cit. p. 26.
286 Handley, op. cit. p. 31.
287 Handley, op. cit. p. 31.
288 Handley, op. cit. pp. 32–33.

Transend on these matters are also applicable to the AER's considerations concerning TransGrid's revenue proposal and the regulatory proposals of ActewAGL, Country Energy, EnergyAustralia and Integral Energy. The AER considers that the approach applied should be consistent across each of these businesses. Accordingly, appendix E is a generic appendix that is applicable to the AER's decisions for Transend, TransGrid and the ACT/NSW DNSPs.

In summary, the AER considers that the proposed allowance for indirect equity raising costs is inconsistent with the regulatory framework. This is primarily because to the extent indirect equity raising costs exist, they can reasonably be expected to be included in the existing return on equity allowance which is based on observed market returns through the CAPM parameters. Alternatively, they are not relevant to the benchmark firm as they relate to the impact on individual shareholders rather than the returns in aggregate (at the firm level). This view is supported by the AER's consultant on this matter, Associate Professor Handley.[289]

In relation to direct equity raising costs, the AER considers that the benchmark rate applied in the draft decision remains the best estimate of costs applicable to the benchmark regulated business. The benchmark rate applied in the draft decision was based on application of the ACG methodology to recent domestic market data. The AER also notes that this benchmark rate was consistent with the range recommended by Associate Professor Handley.[290]

The AER has given consideration to the consultant reports and submissions concerning the benchmark cash flow analysis that is applied to determine the extent to which equity raising is required. Among other issues with the benchmark cash flow analysis, Transend submitted that the draft decision understated the appropriate level of dividends.[291] This resulted in a higher level of retained earnings, which in turn, resulted in a lower external equity requirement. CEG stated that, by lowering dividends, a firm's ability to distribute imputation credits is reduced.[292] CEG also argued for an allowance for the cost of retained earnings.[293] The AER has decided to amend the benchmark cash flow analysis to ensure consistency with the cash flow assumptions in the PTRM. However, it has also taken the level of equity raising through dividend reinvestment plans into account. Further, the AER has decided that it would be inappropriate to include an allowance for the cost of retained earnings.

In summary, the changes to the equity raising cash flow analysis (from the approach applied in the AER's draft decision) include:

- dividends are linked to the level of imputation credits earned in the PTRM (rather than applying a dividend payout ratio to net profit after tax)
- dividend reinvestment is assumed to be 30 per cent of dividends paid
- a benchmark cost of 1 per cent has been applied to equity raised through dividend reinvestment

[289] Handley, op. cit. pp.7–12
[290] Handley, op. cit. p.26.
[291] Transend, *Revised revenue proposal*, op. cit. p. 60.
[292] Transend, *Revised revenue proposal*, op. cit. Appendix 6, p. 29.
[293] Transend, *Revised revenue proposal*, op.cit. Appendix 6, pp. 29–30.

- an error in the presentation of the capex funding requirement has been corrected (in the draft decision the capex funding requirement inappropriately included a WACC and inflation adjustment)

- the amount of capex assumed to be funded by debt has been linked to the increase in the debt component of the RAB to maintain consistency with the benchmark gearing assumption in the PTRM.

Transend proposed to include equity raising costs as part of its forecast opex allowance.[294] The AER considers that there is merit in treating the equity raising cost allowance as a part of Transend's RAB—that is, to amortise the allowance. This would improve transparency, given that the nature of the allowance is associated with capex, and ensure that future revenue resets for Transend would be administratively simpler in the provision of such an allowance.

Further, the AER notes that treating the equity raising cost allowance in perpetuity or in the RAB would be net present value (NPV) neutral. In the 2004 ACG report, it was recommended that equity raising costs be added to the RAB and amortised along with other assets:[295]

> If the regulator has determined that an allowance for the SEO [seasoned equity offering] cost of raising equity for ongoing capital expenditure should be provided for, we recommend that this amount be added to the RAV (i.e. included as part of the capital expenditure cost) and depreciated over the life of the relevant assets.

Accordingly, the amount specified in table 6.12 will be amortised over the life of Transend's RAB for the purposes of providing the equity raising cost allowance associated with the forecast capex over the next regulatory period.[296] This approach is also consistent with the AER's revenue determination for Powerlink.[297]

For the reasons discussed and as a result of the AER's analysis of Transend's revised revenue proposal and additional information, the AER is not satisfied that Transend's proposed equity raising cost allowance reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors. The AER considers the revised benchmark equity raising cost allowance associated with Transend's forecast capex, as set out in table 6.12 represents the efficient costs that a prudent operator in the circumstances of Transend would require to achieve the opex objectives in the next regulatory control period.

The AER's conclusion on benchmark equity raising costs for Transend over the next regulatory control period is set out in table 6.12.

Equity raising costs for the value of the initial RAB

In the 2002 revenue caps for the Victorian and South Australian transmission networks, the ACCC provided allowances for equity raising costs in operating

294 Transend, *Revised revenue proposal*, op. cit. p. 62.
295 ACG, op.cit. p. xiii.
296 A standard life of 41.7 years for amortisation purposes, consistent with Transend's weighted average asset life, has been assumed.
297 AER, *Decision: Powerlink 2007–08 to 2011–12*, op. cit. p. 102.

expenditure relating to the initial RAB. However, in 2003, the ACCC disallowed Transend an allowance for equity raising costs for the value of the initial RAB.[298]

In 2004, the ACCC engaged the Allen Consulting Group (ACG) to undertake a review of issues associated with allowances for the transactions costs incurred in raising debt and equity finance for regulated utilities.[299]

Regarding equity raising costs for the value of the initial RAB, ACG considered that if it was reasonable to assume equity finance could be raised by a firm internally, no allowance was required, but if it was reasonable to assume that a firm would be required to raise funds externally, an allowance would be justified.

ACG further considered that whether the transaction cost of raising equity is relevant to the setting of the RAB depends on the methodology used to set that value, and finally, that there were three equivalent mechanisms that could be used to deliver an allowance for equity raising costs.[300]

In 2007, ACG provided further, clarifying advice after SP AusNet was denied an allowance for equity raising costs by the AER in the draft decision for the 2008/09 – 2013/14 transmission determination. The 2007 advice indicated that the AER had misinterpreted the 'lock-in and roll-forward' methodology put forth by ACG in 2004.

The AER had interpreted the 2004 advice as posing that when considering whether an allowance for the transaction cost of raising equity finance should be provided, the relevant question is "whether a RAB has been established in a previous regulatory decision."[301] However, in the 2007 advice, ACG qualified this interpretation:

> First, the term 'established' must be taken to mean that the regulatory asset value that was set in the previous regulatory decision was to be 'locked-in' and a commitment made to apply the 'roll-forward' approach to updating the value at future reviews…
>
> …Secondly, consideration must also be given to the full circumstances of [the] regulatory decision that established the initial regulatory asset value…It follows that the AER must consider whether an allowance for equity raising costs was provided…when the regulatory asset value was first established.[302]

When the regulatory asset value for SP AusNet (then SPI Powernet) was first established ('locked-in' and committed to be 'rolled-forward') in 2002, an allowance for equity raising costs existed in its operating expenditure. This was recognised by ACG as equivalent to an allowance in the opening RAB itself and was subsequently recognised by the AER in the 2008/09 SP AusNet decision as an opex allowance.[303]

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298 ACCC, *Tasmanian transmission network revenue cap: Decision 2004-2008/09*, December 2003, p.71

299 Allen Consulting Group, *Debt and equity raising transaction costs: Final Report*, December 2004.

300 ACG, *SP AusNet draft decision: transaction cost of raising equity*, 12 October 2007, as found in 'Appendix O – ACG letter on equity raising costs', SP AusNet, *Electricity transmission revised proposal 2008-09 – 2013-14*, 12 October 2007, p. 2.

301 AER, *SP AusNet transmission determination 2008-09 to 2013-14: Draft decision*, 31 August 2007, p. 176.

302 ACG, *Transaction cost of raising equity*, op. cit., pp. 4-5.

303 AER, *SP AusNet final decision,* op. cit, pp. 147, 166.

Similarly, in the 2008/09 ElectraNet decision, the AER applied the same principles, but chose to capitalise the amount in the RAB as part of the roll-forward rather than continuing to grant a perpetual opex allowance.[304]

Submissions received

The AER received a number of submissions in relation to equity raising costs for the value of the initial RAB. Powerlink submitted that the AER has failed to recognise that where the RAB has already been established, ACG considered that the regulator must consider the issue on its merits. Further, the decision to 'lock-in and roll-forward' the RAB was not made until December 2004, so it is appropriate to compensate Transend in the final decision for the costs of raising equity associated with its 2003 opening asset base.[305]

Rio Tinto Alcan (RTA) stated that when the AEMC promulgated the new Chapter 6A of the NER in 2006, it made a deliberate and unambiguous decision to 'lock-in' the opening RAB for each TNSP. To allow Transend to selectively adjust its opening RAB as a result of subsequent regulatory decisions undermines the objectives that motivated the AEMC to 'lock-in' the opening RAB under Chapter 6A.[306]

The Major Employers Group (MEG) and Nyrstar concur with the AER's view to disallow equity raising costs.[307]

Transend revised proposal

Transend asserted in its initial proposal that "Transend's circumstances prior to the ACCC's 2003 revenue cap decision were identical to those of ElectraNet and SP AusNet".[308] However in the revised proposal, Transend has accepted that its circumstances are not strictly identical to those of ElectraNet and SP AusNet, but asserts that "any differences are not sufficiently material to justify a different treatment in relation to equity raising costs on the initial RAB."[309]

Transend engaged Harding Katz to provide advice on the matter. Harding Katz devoted considerable effort in attempting to disprove that the ACCC 'locked-in' Transend's RAB, and further, that the AER ought to follow the 2008 decisions of SP AusNet and ElectraNet that allowed equity raising costs.[310]

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304 AER, *ElectraNet final decision,* op. cit. pp. 18, 88.

305 Powerlink, *Submission on draft decision – Transend transmission determination 2009-10 to 2013-14*, February 2009, p. 3.

306 RTA, *Transend revenue cap 2009/10-2013/14: Submission by Rio Tinto Alcan (Bell Bay) in response to the draft decision of the AER*, February 2009, pp. 13-14.

307 MEG, *Major Employer Group (Tasmania) submission to AER on the Transend transmission revised revenue proposal*, February 2009, p. 3; Nyrstar, *Submission to Transend's revised revenue proposal* (Confidential), February 2009

308 Transend, *Transend transmission revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 31 May 2008, p. 124.

309 Transend, *Revised revenue proposal,* op. cit. p. 60.

310 Harding Katz, *Regulatory treatment of equity raising costs – Report prepared for Transend Networks Pty Ltd*, 31 December 2008, as found in 'Appendix 8 – Harding Katz, *Regulatory treatment of equity raising costs*, December 2008', *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*

In addition, Transend submitted that SKM has provided further advice which demonstrated that Transend's RAB for the purpose of the 2003 revenue cap decision did not include equity raising costs, and also that, contrary to the AER's draft decision, Transend did request equity raising costs in its 2003 revenue application.[311]

Late Responses

After the closing date for submissions, Transend submitted an unsolicited response from Harding Katz to the issues raised by RTA.[312] Although this response was received very late in the determination process, on this occasion, the AER has nonetheless considered the issues raised by Transend, and taken them into account. The AER notes that the NER does not require the AER to take late submissions into account, but in this instance, the AER does not consider that Harding Katz raised any issues that were not already subject to the AER's consideration.

AER Considerations

The question of whether Transend's RAB can be characterised as being 'established' or 'locked-in' has been the subject of considerable debate. However, the AER (in full agreement with RTA[313]) considers that any argument based on the view that Transend's RAB is not 'locked-in' is misconceived. Transend's RAB was unambiguously 'locked-in' by the AEMC when the revised chapter 6A of the NER was promulgated on 16 November 2006. The relevant provision is Schedule 6A.2.1(1)(c) of the NER, which establishes Transend's RAB at $603.6 million as at 31 December 2003.

The policy intention of the AEMC to 'lock-in' the RAB values for all TNSPs in S6A.2.1(1)(c) is clear from the following excerpt:

- Given the Commission's understanding of current practice, locking in the current RAB values for the TNSPs is consistent with the approach proposed in the Rules to only include the value of assets associated with prescribed transmission services in the RAB[,] since these initial values should not include assets associated with negotiated or unregulated services.

- The Commission's decision is that the Draft Rule approach to specifying the initial RAB values is appropriate. The values have undergone considerable scrutiny by the ACCC at each of the previous regulatory reviews. The risks (and thereby costs) associated with these initial values containing errors is therefore low, and likely to be outweighed by the benefits associated with specifying the initial RAB values in the Rule at this time.[314]

Further reasoning for this decision is set out in the AEMC's original rule proposal:

- The potential for periodic optimisation of assets raises uncertainty, which in turn is likely to dampen incentives to invest. The periodic optimisation approach is also information intensive and subjective. Arguments in favour of periodic optimisation of the RAB typically focus on the incentives for efficient investment provided under such an approach. However, the strength of incentives for efficiency depends on the extent of clarity around when/if assets will be optimised.

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311 Transend, *Revised revenue proposal*, op. cit., p. 60.

312 Harding Katz, *Comments on RTA Bell Bay submission on equity raising costs*, 24 March 2009.

313 RTA, *Submission on Transend draft decision*, op. cit., pp. 13-14.

314 AEMC, *Rule determination: National electricity amendment (economic regulation of transmission services) rule 2006 No. 18*, 16 November 2006, pp. 75-76. See also AEMC, *Draft rule determination: National electricity amendment (economic regulation of transmission services) rule 2006*, 26 July 2006, p. 91.

- The Commission does not support periodic optimisation of the RAB, for the reasons given above. The Draft Rule therefore codifies the current lock-in approach in the SRP to determining the RAB, with additional guidance on the criteria to be adopted in undertaking any prudence review of actual expenditure.

- The starting point for the lock-in of the RAB is the opening asset base as already determined in the current regulatory determinations applying to the TNSPs. The dollar values of these initial RABs are set out in the Draft Rule for clarity (Appendix 4). The Commission has taken these values from the values set out in the existing determinations, and has not made its own assessment of the RABs for each TNSP. The Draft Rule requires these RAB values to be adopted for the purposes of the roll-forward.[315]

The result of this decision by the AEMC is that, notwithstanding the ACCC's 2003 revenue cap decision, any discretion or flexibility in determining the initial RAB for Transend (or any other TSNP listed in S6A.2.1(1)(c)) has been removed from the ambit of the AER, and therefore there is no question that Transend's RAB was 'established' or 'locked-in' as at 31 December 2003.

As such, the AER does not consider any matters that deny the conclusion that Transend's RAB is 'locked-in' to be relevant or determinative for the purposes of the AER applying the NER in making Transend's 2009 revenue determination.

However, as mentioned above, the 2007 ACG advice stated that the AER must have regard to the regulatory decision that established the initial RAB to determine if the initial asset value included an allowance for equity raising costs.

ACG identified three equivalent mechanisms that would deliver an allowance for equity raising costs: provide an annual allowance in operating expenses, include an allowance in the WACC, or add the cost to the regulatory asset value.[316]

In the case of Transend, the relevant regulatory decision is the ACCC's 2003 Tasmanian revenue cap because although it was the AEMC who 'locked-in' the initial RAB[317], the AEMC's starting point was the regulatory determination applicable at the time.[318]

In the 2003 Tasmanian revenue cap determination, the ACCC clearly intended that Transend should not be provided with a separate allowance for equity raising costs:

> The ACCC now considers that equity raising costs should not be allowed for Transend because:
>
> - it is unlikely that Transend would incur equity raising costs during the regulatory period, therefore any provision will have to be notional

315 AEMC, *Draft national electricity amendment (economic regulation of transmission services) rule 2006, rule proposal report*, February 2006, pp. 57-58.

316 ACG, *Transaction cost of raising equity*, Op. Cit., p. 3.

317 The AER does concede that the ACCC was not empowered to 'lock-in' Transend's RAB in 2003, as at that time the ACCC only had the power to revalue sunk assets (National Electricity Code, cl 6.2.3(d)(4)(iv)).

318 AEMC, *Rule proposal report*, op. cit., p. 58.

- return on equity is a benchmark return calculated using the CAPM.[319]

Further to this, in the two prior 2002 decisions concerning Victoria and South Australia, the ACCC stated that it would review the matter of equity raising costs in future decisions.[320] The fact that the ACCC then denied equity raising costs for Transend demonstrates that the ACCC's further consideration of the issue led it to conclude that equity raising costs should not be allowed on the initial RAB. In the Transend draft decision, the AER stated that it considered that the ACCC made Transend's valuation inclusive of equity raising costs. This was because Transend's initial RAB is an 'established' RAB, and in such cases, ACG stated that there need not be a transaction cost associated with raising the additional equity finance associated with the capital expenditure over time.[321]

The AER also notes that where the initial RAB was set as an estimate of the then optimised depreciated replacement cost (ODRC) of the network, but an allowance for equity raising costs was not included in the RAB, ACG considered that the omission of equity raising costs would have been an error in the initial asset value. However, despite this, ACG considered it would be inappropriate to then include an allowance even though it would remedy the error:

> If an initial asset value is set at ODRC and then 'locked-in', with a commitment made to update that value thereafter using the 'roll-forward' approach, then…if the asset value did not include an allowance for equity raising costs, it should not be reopened to include such an allowance given that a central feature of the roll-forward approach is not to reopen the locked-in value.[322]

So even if Transend's initial RAB did not include equity raising costs, although this valuation would have been in ACG's view potentially an error, the 'locked-in' RAB cannot now be reopened to include such an allowance, as that action would be fundamentally inconsistent with a key feature of the regulatory framework.

The AER further notes that there is nothing in the framework provided in the NEL and chapter 6A of the NER (including the transitional provisions at rule 11.6) which requires the AER, in the course of making a transmission determination, to redress what may be retrospectively realised, to be a past incorrect decision made by the AER, the ACCC or another regulator.[323] In any event, the AER does not consider the previous decision of the ACCC to have been in error. Rather, it is clear that the ACCC fulfilled its 2002 commitment to reconsider its approach to equity raising costs and, as already noted in the 2003 Transend decision, resolved not to allow equity raising costs, whether on the initial RAB or on additions to the Transend asset base.

By contrast, SP AusNet's 2003 operating expenditure included a separate allowance for equity raising costs, which is one of the three mechanisms identified by ACG. This allowance was therefore equivalent to the costs being included in the opening

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319 ACCC, *Tasmanian transmission network revenue cap 2004-2008/09*, 10 December 2003, p. 72.

320 ibid.

321 ACG, *Transaction cost of raising equity*, op. cit. p. 2.

322 ACG, *Transaction cost of raising equity*, op. cit. pp. 2-3.

323 Making a transmission determination refers to the AER meeting the requirements set out at rule 6A.14.

RAB itself. When the opening RAB does include an allowance for equity raising costs, ACG concluded the following:

> If the initial asset value did include an allowance for equity raising costs, then clearly the allowance should remain in the regulatory asset value – it would have been correct for the initial asset value to include an allowance for equity raising costs and…the value should not be reopened after it has been 'locked-in' in any event.[324]

As such, SP AusNet was entitled to continue receiving an allowance for equity raising costs in the 2008/09 – 2013/14 regulatory period. ElectraNet also had an allowance for equity raising costs in its operating expenditure, so the AER's decision to grant ElectraNet an equity raising costs allowance was based on the same principles as the SP AusNet decision. As for Transend, equity raising costs were not included in the operating expenditure allowance for 2004. In this respect, Transend's circumstances are therefore not comparable to SP AusNet and ElectraNet.

In the draft decision the AER did not form the view that the initial value of Transend's RAB was set exclusive of equity raising costs. Transend subsequently submitted additional material in the form of a letter from SKM which prima-facie supports Transend's contention that its asset base did not include equity raising costs.[325] But the AER is conscious of the strongly expressed opinion of ACG that once an asset base is 'locked-in' it would be an error to reopen the asset base to retrospectively add an allowance. The AER also notes that ACG reported that including an amount in the RAB was one of three equivalent mechanisms for providing such an allowance, the other mechanisms being as an opex allowance and as an increment to the weighted average cost-of-capital.[326] Consequently the AER considers that if it is not appropriate to make an allowance in one form then it would be an error to make an equivalent allowance under one of these alternative mechanisms. The AER therefore does not consider that the arguments put forward by Transend justify retrospectively allowing equity raising costs for Transend that were disallowed in the ACCC's 2003 revenue cap decision.

While the AER considers that consistency with previous decisions is important, the AEMC has made it clear that the AER cannot allow a TNSP to selectively adjust its opening RAB each time there is a change in the regulatory regime. As noted by RTA, to do so undermines the very objectives that motivated the AEMC to 'lock-in' the opening RAB under Chapter 6A.[327]

The AER also notes that the operation of clause 11.6.9 of the NER, while relevant to the issue at hand, is not an avenue available for Transend to pursue in terms of adjusting the RAB. Clause 11.6.9 provides:

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324 ACG, *Transaction cost of raising equity*, op. cit. pp. 2-3.

325 SKM, *Advice regarding the calculation of the regulatory asset base*, as found in *Appendix 7, Transend revised proposal*, op. cit.

326 Although the three recognised mechanisms of delivering an allowance for equity raising costs are considered by ACG to be equivalent, ACG's recommended approach was to capitalise these costs in the RAB. The AER's recent regulatory practice has been to capitalise equity raising costs in the RAB.

327 RTA, *Submission on Transend draft decision*, op. cit. p. 14.

> In making a revenue determination for the first regulatory control period, the value of the regulatory asset base at the beginning of the first regulatory year of that period calculated in accordance with clause S6A.2.1(f), **may be adjusted having regard to an existing revenue determination and any other arrangements agreed between the AER and the Transmission Network Service Provider**.[328]

No such “arrangements” exist that are “agreed” between the AER and Transend, nor stipulated in the existing ACCC determination, and as such, the AER cannot make any adjustment to Transend’s initial RAB.

RTA also notes in its submission that Transend has attempted to side-step the opening RAB issue by seeking to recover equity raising costs through its operating expenditure allowance rather than the value of the RAB itself.[329] Furthermore, in Harding Katz’s commentary on the issues raised by RTA, Harding Katz has once again suggested equity raising costs be included as an opex allowance. Therefore, Transend has requested equity raising costs as an opex allowance in its initial proposal,[330] its revised proposal,[331] and indirectly, via Harding Katz’s commentary.[332]

The AER agrees with RTA’s view that to make an opex allowance for equity raising costs where none had previously existed in lieu of an adjustment to the RAB would have the effect of frustrating the intent of the AEMC when Rule 11.6.9 was framed.

While Harding Katz is correct in stating that the AER is not precluded from considering Transend’s claim for equity raising costs as an opex allowance on its merits, the view that clause 11.6.9 is irrelevant to Transend is flawed.[333] Clause 11.6.9 is a specific means by which the AER is able to have regard to prior regulatory determinations when considering an issue on its merits and was relevant to the previous AER determinations for SP AusNet and ElectraNet. As mentioned earlier, SP AusNet and ElectraNet were granted an equity raising cost allowance because an allowance was found to exist in the 2002 ACCC determinations. Applying the same regulatory principles, having regard to the ACCC’s existing 2003 determination for Transend shows no such allowance. This is the fundamental, material point of distinction between Transend on one hand, and SP AusNet and ElectraNet on the other. The AER’s approach has been to consistently apply the intention of the current regulatory determination in addressing this issue.

While the ACCC 2003 decision may have been inconsistent with other contemporaneous decisions it was nonetheless a result of the regulator’s stated intention to give further consideration to the issue at the time. Although this outcome may not be desirable for Transend, the assertion by Harding Katz that Transend is being treated with regulatory inconsistency[334] is inaccurate.

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328 Emphasis added.

329 RTA, *Submission on Transend draft decision*, Op. Cit., p. 14.

330 Transend, *Revenue proposal*, op. cit., pp. 123-4.

331 Transend, *Revised proposal,* op. cit., p. 60.

332 Harding Katz, *Comments on RTA submission,* op. cit. pp. 2, 4, 5.

333 Harding Katz, *Comments on RTA submission,* op. cit. p. 4.

334 Harding Katz, *Regulatory treatment of equity raising costs*, op. cit., p. 19; Harding Katz, *Comments on RTA submission,* op. cit. p. 5.

The AER has considered Transend's claim for equity raising costs for the value of the initial RAB on its merits on several occasions, and, as stated in the Transend draft decision, the AER does not consider it appropriate to retrospectively provide Transend with an allowance for equity raising costs for the value of the initial RAB. The AER is not satisfied that Transend's circumstances are such that equity raising costs for the value of the initial RAB would reasonably reflect the costs that a prudent operator in the circumstances of Transend requires to achieve the operating expenditure objectives, and hence satisfy clause 6A.6.6(c)(2) of the NER.

Therefore no adjustment to the value of $603.6 million as set in schedule 6A.2.1 should apply in relation to this claim. The AER concludes that it is not appropriate to provide Transend with an allowance for equity raising costs associated with the value of Transend's initial RAB.

AER conclusion

The AER's conclusions on an equity raising allowance for Transend are provided in table 6.12.

Table 6.12: AER conclusions on equity raising cost allowance for Transend ($ million)

Line item	AER decision	Notes
Dividends	81.66	Set to distribute imputation credits assumed in the PTRM
Dividends reinvested	24.5	30 per cent of dividends paid out
Cost of DRP	0.24	1 per cent of dividends reinvested
Capex funding requirement	641.16	[Note to be added]
Debt component	320.35	Set to equal 60 per cent of RAB increase (not capex)
Equity component	320.81	Residual of capex funding requirement and debt component
Retained cash flows available for reinvestment	300.63	Includes dividends reinvested
External equity requirement	20.18	Equal to equity component less retained cash flows
External equity raising cost	0.55	External equity requirement multiplied by benchmark rate (2.75 per cent)
Total equity raising cost (nominal)	0.80	Sum of DRP costs and external equity raising costs
Total equity raising cost (real, $2008-09)	0.81	To be amortised at commencement of regulatory control period

The AER considers the revised benchmark equity raising allowance associated with Transend's forecast capex represents the efficient costs that a prudent operator in the circumstances of Transend would require to achieve the capex objectives in the next regulatory control period.

6.6.7 Self insurance

In the draft decision, the AER made no adjustment to Transend's self insurance proposal, which is shown in table 6.13.

Table 6.13: Transend's self insurance proposal ($m 2008-09)

	2009–10	2010–11	2011–12	2012–13	2013–14	5 years Total
Self insurance	0.8	0.8	0.8	0.8	0.8	3.9

Source: Transend, *Transend transmission revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 31 May 2008, p.125.

However, the AER rejected the component attributed to a terrorism event in Transend's self insurance proposal because of the difficulty in calculating a risk premium for a terrorism event and because a terrorism event is listed as a defined pass though event under the NER.[335] As such, the AER requested that Transend and/or Marsh Risk Consulting Services erase the words "terrorism", "terrorist attack" or other related words from appendix 21 of the proposal.[336]

Transend did not provide an amended version of appendix 21 in its revised revenue proposal.[337]

The AER requests that Transend and/or Marsh Risk Consulting Services erase the words "terrorism", "terrorist attack" or other related words from appendix 21 of the proposal.

6.7 AER conclusion

The AER has considered Transend's revised forecast total opex of $254 million ($2008–09) and, for the reasons outlined in this chapter, is not satisfied that this total opex forecast proposed by Transend 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 the relevant TNSP would require to achieve the opex objectives
- a realistic expectation of the demand forecast and cost inputs required to achieve the opex objectives.

In reaching 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 Transend's total forecast opex reasonably reflects the opex criteria, under clause 6A.6.6(d), it must not accept the forecast opex in Transend's revised revenue proposal. The AER is therefore required under clause 6A.14.1(3)(ii) to provide an estimate of the total opex that Transend will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

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335 AER, *Transend draft decision*, op. cit. p.187.

336 ibid., p.188.

337 Transend, *Revised revenue proposal*. op. cit.

On the basis of its analysis of Transend's proposed opex forecast and the advice of Nuttall Consulting, the AER has applied a reduction of $0.3 million to Transend's revised forecast opex. This results in an amended forecast opex allowance of $254 million for the next regulatory control period and is as shown in table 6.14. In addition, the AER rejects Transend's claim for additional opex allowance if Transend's claim for capex was not granted in full. In coming to this view the AER:

- notes that Nuttall consulting did not recommend any additional opex
- is not satisfied that Transend has demonstrated that the opex allowance provided in the draft decision was insufficient or that additional opex is warranted[338]
- the AER's draft decision estimated a forecast capex allowance and a forecast opex allowance representing the amounts that a prudent operator in the circumstances of Transend would require to meet the capex and opex objectives respectively. Given that this final decision provides Transend with capex above the draft decision, Transend does not require a commensurate increase in the approved opex allowance.

Table 6.14: AER's conclusion on Transend's total opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER's total opex allowance (draft decision)	50.3	51.0	50.9	53.8	54.2	260.2
Transend's revised proposed total opex	54.2	55.6	55.6	58.7	59.2	283.3
Adjustment to equity raising costs – capex[a]	-2.3	-2.3	-2.3	-2.3	-2.3	11.4
Adjustments arising from modelling[b]	-2.3	-3.0	-3.4	-4.1	-4.9	-17.6
AER's total adjustments	-4.6	-5.2	-5.6	-6.4	-7.2	-29.0
AER's total opex allowance	49.7	50.3	50.0	52.3	52.0	254.3

(a) Equity raising costs have been removed from opex and the amount of equity raising costs calculated by the AER have been capitalised.

(b) These adjustments reflect changes to asset growth (resulting from amended capex allowance), actual CPI for 2007–08 and 2008–09, removal of replacement capex for transitional services, and debt raising costs (resulting from amended capex allowance).

This amended allowance represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of Transend would require to achieve the opex objectives. The AER is satisfied that the amended total forecast opex of $254.3 million over the next regulatory control period reasonably reflects the opex criteria, taking into account the opex factors.

338 Transend, *Email revised models 16 April*, April 2009.

7 Efficiency Benefits Sharing Scheme

7.1 Introduction

This chapter sets out the AER's consideration of issues relating to the Efficiency Benefit Sharing Scheme (EBSS) raised in response to the AER's draft decision and matters raised in Transend's January 2009 revised revenue proposal.

7.2 AER draft decision

The AER will apply the EBSS to Transend for the next regulatory control period. In the event that actual demand growth is outside the range of scenarios modelled in the development of Transend's approved forecast capex and for the purposes of the EBSS, forecast opex should be adjusted based on the same models (opex and capex) used to develop Transend'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 and equity raising costs
- insurance and self-insurance
- superannuation provisions.

These are in addition to the costs of pass through events and non-network alternatives, which are directly excluded by the EBSS.

The AER made an error in its calculation of the forecast controllable opex for Transend. This has been rectified in table 7.1. This table was used in the draft decision to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS.[339]

Table 7.1 Transend's forecast controllable opex for EBSS purposes ($m, 2008/09)

	2009–10	2010–11	2011–12	2012–13	2013–14
Total forecast opex	**50.3**	**51.0**	**50.9**	**53.8**	**54.2**
Debt and equity raising costs	0.5	0.6	0.6	0.6	0.7
Insurance and self-insurance costs	1.7	1.8	1.9	2.0	2.1
Superannuation provisions	0	0	0	0	0
Non-network alternatives	3.9	2.6	0.0	0.0	0.0
Forecast opex for EBSS purposes	**44.1**	**46.0**	**48.3**	**51.1**	**51.4**

339 AER, *Electricity transmission network service providers efficiency benefit sharing scheme*, September 2007, p. 7.

Source: AER, *Transend transmission determination 2008–09 to 2013–14: Draft decision*, 21 November 2008, p. 208.

7.3 Transend revised proposal

Transend has accepted the AER's draft decision with respect to the efficiency benefits sharing scheme.[340]

7.4 Submissions

There were no submissions made by stakeholders regarding Transend's EBSS.

7.5 AER conclusion

The AER confirms its draft decision concerning the EBSS. The AER has updated Transend's forecast controllable opex for EBSS purposes in table 7.2 to account for the changes in opex that occurred in chapter 6 of this final decision.

Table 7.2 Transend's forecast controllable opex for EBSS purposes ($m 2008/09)

	2009–10	**2010–11**	**2011–12**	**2012–13**	**2013–14**
Total forecast opex	**49.7**	**50.3**	**50.0**	**52.3**	**52.0**
Debt and equity raising costs	0.5	0.5	0.6	0.6	0.6
Insurance and self-insurance costs	1.8	1.8	1.9	2.1	2.2
Superannuation provisions	0.0	0.0	0.0	0.0	0.0
Non-network alternatives	3.9	2.6	0.0	0.0	0.0
Forecast opex for EBSS purposes	**43.5**	**45.3**	**47.4**	**49.7**	**49.2**

340 Transend, *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 14 January 2009, p. 62

8 Service target performance incentives

8.1 Introduction

This chapter sets out the AER's consideration of issues relating to the Service Target Performance Incentive Scheme (scheme) raised in response to the AER's draft decision, including matters raised in Transend's revised revenue proposal.

8.2 AER draft decision

In the draft decision the AER rejected Transend's use of deadbands for all measures, altered various targets, caps and collars as required during the process and explained its reasoning in the draft decision.[341]

Table 8.1 sets out the AER's draft decision on the caps, collars, performance targets and weightings to apply to Transend for the next regulatory control period.

Table 8.1: Caps, collars, targets and weightings to apply to Transend

Parameter	Recommended values			
	Collar	Target	Cap	Weighting
Circuit availability (%)				*MAR (%)*
Transmission circuit availability (critical)	97.90	99.13	99.75	0.20
Transmission circuit availability (non-critical)	98.48	98.97	99.47	0.10
Transformer circuit availability	98.67	99.28	99.90	0.15
Loss of supply event frequency (no.)				*MAR (%)*
> 0.1 (x) system minutes	21	15	8	0.20
> 1.0 (y) system minutes	4	2	0	0.35
Average outage duration (minutes)				*MAR (%)*
Transmission Lines	529	326	124	0.0
Transformers	1428	712	354	0.0

Source: AER, *Transend transmission determination 2008–09 to 2013–14: Draft decision*, 21 November 2008, p. 226.

[341] AER, *Transend transmission determination 2008–09 to 2013–14: Draft decision*, 21 November 2008, p. 226.

8.3 Transend revised proposal

Transend has implemented all aspects of the AER's draft decision with the exception of the caps for the transformer availability measure and the loss of supply > 0.1 system minute.

Transend has also stated that it wishes to retain an option to introduce the market impact parameter during the forthcoming regulatory control period if additional data and analysis indicate that it is practical to do so.[342] Table 8.2 sets out Transend's revised values for the scheme.

Table 8.2: Transend's proposed caps, collars, targets and weightings for the loss of supply event frequency parameter

Parameter	**Recommended values**			
	Collar	**Target**	**Cap**	**Weighting**
Circuit availability (%)				*MAR (%)*
Transmission circuit availability (critical)	97.90	99.13	99.75	0.20
Transmission circuit availability (non-critical)	98.48	98.97	99.47	0.10
Transformer circuit availability	98.67	99.28	99.59	0.15
Loss of supply event frequency (no.)				*MAR (%)*
> 0.1 (x) system minutes	21	15	9	0.20
> 1.0 (y) system minutes	4	2	0	0.35
Average outage duration (minutes)				*MAR (%)*
Transmission Lines	529	326	124	0.0
Transformers	1428	712	354	0.0

Source: Transend, *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 14 January 2009, p 69.

8.4 Submissions

The AER received a submission from Rio Tinto Alcan (RTA) concerning Transend's application for an option to opt into the market impact parameter of the scheme.

342 Transend, *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 14 January 2009, p 68.

8.5 Issues and AER considerations

8.5.1 Option to introduce the Market Impact of Transmission Congestion parameter

AER draft decision

The AER stated in its draft decision that it would not apply the market impact of transmission congestion (MITC) parameter to Transend on the basis of Transend previously informing the AER that it did not have sufficient information to introduce a target.

Transend revised proposal

Transend has stated that it wants to retain an option to introduce the market impact parameter during the forthcoming regulatory control period if additional data and analysis indicate that it is practical to do so.[343]

Submissions

The AER received a submission from RTA concerning Transend's application for the option to introduce the market impact parameter of the scheme during the next regulatory control period. RTA stated that clause 6A.7.4(b) of the NER requires the performance incentive scheme parameters be published at the same time the scheme is published. Transend did not have a market impact parameter applied to it under the scheme. RTA further stated that clause 6A.7.4(f) of the NER prohibits the AER from amending a scheme in respect of a regulatory control period that will commence within15 months of the amendment coming into operation. RTA therefore asserts that the NER does not permit Transend to opt into the scheme.

AER considerations

The AER has reviewed clause 6A.7.4 of the NER in relation to Transend's eligibility to opt into the MITC. Under the STPIS guidelines[344] section 2.2(a) states that the market impact component does not apply to Transend. RTA is correct in its interpretation of clause 6A.7.4(f) of the NER. In addition, section 2.3(b) of the scheme also states that the AER may not change the application of the scheme within15 months of it coming into operation. RTA is also correct in relation to the timing of publication of the performance incentive scheme parameters, although the AER notes that the applicable clause is 6A.7.4(c) of the NER. Therefore, the AER rejects Transend's proposal to opt into the MITC for the next regulatory control period.

8.5.2 Cap for the Transformer Circuit Availability Measure

AER draft decision

The AER rejected Transend's proposed treatment of caps and collars and applied a cap and collar at ±2 standard deviations either side of the target.

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343 Transend, *Revised revenue proposal*, op. cit. p.68.

344 AER, *Electricity transmission network service providers: Service target performance incentive scheme*, March 2008, p. 3.

Transend revised proposal

Transend considered that the transformer circuit availability cap is too close to the limit of performance and is beyond an attainable level of performance for the Tasmanian transmission system in the next regulatory control period. In order to attain the cap Transend stated it would need to reduce its transformer outage time by 86 per cent. Transend proposes that the cap for this parameter be set at +1 standard deviation from the target to give a more reasonable cap. Transend stated this would also require them to achieve a significant 43 per cent level of improvement compared to previous performance.[345]

AER considerations

The AER considers that caps and collars as outlined in section 3.3(e) of the scheme must be calculated using a sound methodology by reference to the performance targets. The scheme does not consider that the cap or collar of the target band should be easily achievable. In fact, the guidelines do not give any indication that the cap and collar should be achievable at all.

The statistical basis for the assumption of ±2 standard deviations either side of the target is that, assuming a normal distribution, there is a 95 per cent confidence interval, which suggests that only 1 transformer outage event in a 20 year period occurs outside the confidence interval. Therefore, under this standard approach that has been applied to caps and collars, such an event should only occur once in 20 years.

This in turn suggests that the caps and collars should not be easily achievable as this gives greater incentive for each TNSP to try to improve performance during the next regulatory control period. Therefore the AER considers that the targets it set for Transend are appropriate. The AER does not consider that the methodology proposed by Transend for reducing the transformer circuit availability measure to +1 standard deviation from the target is appropriate.

Transend's arguments are based on the idea of an efficiency frontier beyond which the operation of the transmission network is not possible. The AER considers that this argument has some merit. The AER will be addressing the issue of calculating the cap and collar when an NSP is approaching the efficiency frontier in its next review of the STPIS framework. Transend has not satisfied the AER that it has produced a sound methodology for applying the efficiency frontier that is better than the ±2 standard deviations either side of the mean approach that is already applied to the cap. Transend proposed methodology for applying an efficiency frontier needs to be symmetrically applied and non-arbitrary. The current approach proposed by Transend appears to select a measure approaching 100 per cent and arbitrarily changes it.

The AER also notes that while the current cap is high, several other TNSPs, such as ElectraNet and TransGrid, have caps at similar levels. While each TNSP is different, the scheme is applied to all TNSPs across the NEM. Therefore the AER rejects Transend's proposed change to the transformer average outage duration cap.

345 Transend, *Revised revenue proposal* op. cit. p. 66

8.5.3 Cap for the Loss of Supply >0.1 System Minutes

AER draft decision

The AER rejected Transend's proposed treatment of caps and collars and applied a cap and collar at ±2 standard deviations either side of the target.

Transend revised proposal

Transend stated that the loss of supply >0.1 system minutes is asymmetrical, so that the bonus for improvement is less than the penalty for performance degradation. This is due to the cap at +2 standard deviations being rounded to 8. Transend has requested that the cap and collar be symmetrical.[346]

AER considerations

The AER notes Transend's arguments on the loss of supply measure concerning the need for symmetrical weightings on the caps and collars for rewards and penalties. However, section 3.3(f) of the guidelines states that a proposed cap and collar may result in a symmetric or asymmetric incentive for the TNSP under the scheme.

In the case of this scheme the caps and collars applying to the transmission line circuit availability (critical) and average outage duration (transformers) sub-parameters are both asymmetric due to the standard methodology of applying ±2 standard deviations either side of the target causing a violation of the natural limit (i.e. a cap greater than 100 per cent or lower than 0). In this case these asymmetric caps are favourable to the firm.

The AER notes that the calculation of the loss of supply measure is different from the calculation of other measures. In the case of the loss of supply the AER calculates ±2 standard deviations either side of the target and then rounds this figure to the nearest integer value. This has resulted in an asymmetric cap which is unfavourable to the firm.

The reasoning behind this calculation is that there can only be whole integer loss of supply events. Therefore the caps, collars and targets must be rounded to the closest integer value to avoid each of these values becoming a target band. This is the approach the AER has adopted for the loss of supply measures.

Transend, in its revised proposal, has proposed to make the cap and collar symmetrical noting that the 2007 result was very low for the sample period. However, the AER notes under section 3.3(f) of the guidelines, a proposed cap and collar may result in symmetric or asymmetric incentives for the TNSP. The AER requested Transend provide the AER with its methodology for calculating the new cap and collar in the revised proposal as section 3.3(e) requires the proposed cap and collar be based on a sound methodology.

Transend supplied its methodology for calculating this revised measure. Transend altered the methodology for calculating this cap by rounding the standard deviations and target then applying ±2 standard deviations either side of the target. This allows for a symmetrical result with a cap of 9 and a collar of 21 around a mean of 15. The

346 Transend, *Revised revenue proposal*, op. cit. p. 67

AER recognises that a symmetrical scheme will provide a better incentive for any TNSP to improve performance and considers that the changes proposed by Transend reflect this outcome. Therefore where possible the AER will attempt to apply symmetrical caps and collars. However, the AER notes that it is not required to do this. The AER accepts this adjustment to the methodology of calculating the cap and collar for this measure as sound and accepts the new cap for this measure.

8.6 AER conclusion

The AER confirms the conclusions of its draft decision with the exception of the cap for loss of supply >0.1 system minutes. Transend has proposed a reasonable alteration to the methodology for calculating this cap and collar that results in a symmetrical outcome. In the AER's opinion the STPIS should be applied symmetrically where possible in order to offer the proper incentive to the business to improve its performance.

The AER is not satisfied that Transend's revised methodology for calculating the cap for the transformer circuit availability measure is reasonable as required by section 3.3(e) of the scheme. The AER notes the validity of Transend's remarks concerning the efficiency frontier but does not consider the methodology it has applied as appropriate. The AER rejects Transend's revised proposal to alter the cap for the transformer circuit availability measure.

The AER rejects Transend's proposal to opt into the MITC for the next regulatory control period as Transend is specifically excluded from participating in the MITC adjusted scheme. No changes can be made to the scheme under clause 6A.7.4(c) and 6A.7.4(f).

The definitions that apply to Transend for the next regulatory control period are detailed in appendix F. The performance incentive curves are detailed in appendix G.

The caps, collars, performance targets and weightings to be applied to Transend during the next regulatory control period are set out in table 8.3.

Table 8.3: Caps, collars, targets and weightings to apply to Transend

Parameter	Recommended values			
	Collar	Target	Cap	Weighting
Circuit availability (%)				*MAR (%)*
Transmission circuit availability (critical)	97.90	99.13	99.75	0.20
Transmission circuit availability (non-critical)	98.48	98.97	99.47	0.10
Transformer circuit availability	98.67	99.28	99.90	0.15
Loss of supply event frequency (no.)				*MAR (%)*
> 0.1 (x) system minutes	21	15	9	0.20
> 1.0 (y) system minutes	4	2	0	0.35
Average outage duration (minutes)				*MAR (%)*
Transmission Lines	529	326	124	0.0
Transformers	1428	712	354	0.0

9 Maximum allowed revenue

9.1 Introduction

This chapter sets out the AER's calculation of Transend's maximum allowed revenue (MAR) for the next regulatory control period based on the revised building block components allowed in this final decision. It also sets out the AER's consideration of Transend's revised proposal to change the standard asset life of its computers, software and office machines asset class for the purposes of determining the regulatory depreciation allowance. Except as specified in this final decision, the AER maintains the conclusions set out in the draft decision.

9.2 AER draft decision

The AER determined an annual building block revenue requirement for Transend that increases from $176 million in 2009–10 to $244 million in 2013–14 ($nominal) using the building block approach defined in the draft decision and part 1 of Transend's transmission determination. The total MAR for Transend over the next regulatory control period was determined to be $1043 million.

Transend's MAR for the next regulatory control period was established using a building block approach. For the purpose of determining the expected MAR over the next regulatory control period, the AER set the first year MAR equal to the annual building block revenue requirement for that year and applied an X factor of –5.8 per cent in subsequent years. The smoothed MAR is equivalent to the unsmoothed MAR as they both equal $787 million in Net Present Value (NPV) terms.

Table 9.1: AER's draft decision on the maximum allowed revenue ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Return on capital	95.8	109.2	124.3	132.9	141.1	603.2
Regulatory depreciation	24.4	25.0	23.1	26.2	29.9	128.6
Opex allowance	51.6	53.7	54.9	59.5	51.5	281.1
Opex efficiency (glide path) allowance[a]	0.0	0.0	0.0	0.0	0.0	0.0
Net tax allowance	4.6	5.4	6.1	6.7	7.3	30.2
Annual building block revenue requirement (unsmoothed)	176.4	193.3	208.4	225.4	239.8	1043.1
MAR (smoothed)	176.4	191.3	207.4	225.0	244.0	1044.0
X factor	–18.9	–5.8	–5.8	–5.8	–5.8	–

Source: AER, *Transend transmission determination 2008–09 to 2013–14: Draft decision*, 21 November 2008, pp.243-4.

(a) An allowance for opex efficiency resulting in the current regulatory period.

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 Tasmania.[347] Based on this approach, the AER estimated that its draft decision would result in an 8.1 per cent per annum (nominal) increase in average transmission prices from 2008-09 to 2013-14 or an increase of 5.4 per cent per annum in real terms ($2008–09).

9.3 Transend revised proposal

Transend applied the post-tax building block approach to calculate its revised proposed revenues. Transend's revised proposed revenues were determined on the basis of a nominal opening RAB of $961 million.[348] It requested nominal unsmoothed revenues of $181 million in 2008–09, increasing to $250 million in 2013–14.[349] Transend's MAR for the final year of its current regulatory period (2007–08) is $145 million. Table 9.2 summarises Transend's total proposed annual building block revenue requirement (unsmoothed) and the expected MAR for each year of the next regulatory control period.[350]

Table 9.2: Transend'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	90.1	105.2	121.1	129.3	138.3	584.0
Regulatory depreciation	30.9	32.5	29.2	34.3	38.1	165.0
Opex allowance	55.3	57.8	58.9	63.4	65.1	300.5
Opex efficiency (glide path) allowance[a]	0.0	0.0	0.0	0.0	0.0	0.0
Net tax allowance	5.1	5.9	6.7	7.4	8.0	33.1
Annual building block revenue requirement (unsmoothed)	181.4	201.5	216.0	234.3	249.5	1082.7
MAR (smoothed)	181.4	197.6	215.2	234.5	255.4	1084.0
X factor	–23.0	–6.9	–6.9	–6.9	–6.9	–

Source: Transend, *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 14 January 2009, p. 73.

Transend has proposed its expected MAR over the next regulatory control period by setting the first year's MAR equal to the first year's annual building block revenue

347 The forecast energy delivered (customer sales) figures were obtained from Transend 2008 Annual Planning Report.

348 Transend, *Transend transmission revised revenue proposal for the period 1 July 2009 to 30 June 2014*, 14 January 2009, p. 21.

349 ibid., p. 73.

350 While the total value of the annual building block revenue requirement is different from the total value of the expected MAR (smoothed), the two are equivalent in NPV terms.

requirement and applying an X factor of –6.9 per cent to escalate its MAR annually for each of the four remaining years.[351]

The implied energy delivered unit cost of this MAR (average transmission charges) is $16.57 per MWh in 2008–09 increasing at a nominal average annual rate of 9.2 per cent to $20.82 per MWh in 2013–14. The AER calculated, in nominal terms, that this average increase in transmission charges will increase the average residential customer bill of $1400 by approximately $37.30 in the first year and $13.10 for each following year of the regulatory period. This is approximately $18.00 or 8.9 per cent per year.

Transend estimates, in real terms, that the average increase in transmission charges will increase the average residential customer bill of $1400 by approximately $33.30 in the first year and $8.19 for each following year of the regulatory period. The AER estimates this is approximately $13.21 or 6.9 per cent per year.

9.4 Submissions

The AER received a submission from the EUAA concerning its inability to reconcile the increased prices and the increased revenues set by the AER for Transend. The EUAA have stated that it calculates prices as increasing 30 per cent higher in real terms ($2008/09) (at 5.4 per cent per annum over the period) while revenues will be a little under 60 per cent higher in real terms at the end of the regulatory period than at the start of the regulatory period.[352]

At the pre-determination conference, the MEG raised the issue of removing the residual depreciation value of replaced assets from the RAB in the current regulatory period.[353]

9.5 Standard asset lives

9.5.1 AER draft decision

The AER approved the asset lives proposed by Transend subject to some exceptions.[354] These exceptions were:

- transfer insulator assemblies, dampers and galvanised steel earthwires to the 60 year transmission line asset class
- transfer bridges to the 60 year transmission line asset class
- increase the 'short life' asset classes from 3 years to 4 years

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351 Transend, *Transend transmission revised revenue proposal for the period 1 July 2009 to 30 June 2014*, 18 January 2009, p. 73.

352 EUAA, *Submission to AER on the draft decision on Transend's regulated revenue for 2009 to 2014 regulatory period*, 13 February 2009, p. iv, 1

353 MEG, *Submission to AER on Transend revenue proposal*, 11 August 2008, ,p. 7

354 AER, *Transend transmission determination 2008–09 to 2013–14: Draft decision*, 21 November 2008, p. 235-239.

- increase the ‘other - short life’ asset class from 5 years to 9 years

In the draft decision the AER determined that the asset lives proposed by Transend for these asset classes do not provide for depreciation over their economic and/or tax life. The AER instead determined that computer equipment (common to the ‘short life’ asset classes) would be depreciated over four years and the ‘other short life’ five year asset class should be depreciated over nine years due to the composition of its assets (which included cars and office furniture).

9.5.2 Transend revised proposal

Transend has implemented all aspects of the AER’s draft decision in relation to asset lives with the exception of the standard asset life for ‘other - short life (5 years)’. Transend contends that this asset class is composed of 45 per cent computer assets.

Table 9.3 contains an overview of Transend’s revised proposed standard asset lives compared to those in the AER draft decision.

Table 9.3: Transend’s revised proposal on standard lives and asset classes

Asset class	Transend Revised Proposed Standard Asset Life (Years)	AER Draft Decision Standard Asset Life (Years)
Transmission Line Assets – long life	60	60
Transmission Line Assets – medium life	45	45
Transmission Line Assets – short life	10	10
Substation assets – long life	60	60
Substation assets – medium life	45	45
Substation assets – short life	15	15
Protection and Control – short life	15	15
Protection and Control – short life	4	4
Transmission operations – short life	10	10
Transmission operations – short life	4	4
Other – medium life	40	40
Other – short life	5	9
Other – short life	4	4
Land	n/a	n/a

Source: Transend, *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 14 January 2009, p. 71-72.
AER, *Transend transmission determination 2008–09 to 2013–14: Draft decision*, 21 November 2008, p. 238.

9.5.3 AER considerations

Transend's revised asset life

The AER has assessed the additional information submitted by Transend on the appropriate standard asset life for 'other - short life (5 years)' asset class. The AER considers that Transend has not appropriately defined its assets in these asset classes. Transend's documentation of the 'other - short life (5 years)' asset class stated that this asset class includes mobile phones, office equipment, office furniture, motor vehicles and trailers.

It was not clear in Transend's original proposal that the 'other – short life (5 years)' asset class also included computer equipment such as computer upgrades for transmission operations including desktop workstations, servers and software.[355] The AER considered that these assets should be maintained in the 'other – short life (4 years)' category or the 'transmission operations – short life (4 years)' which would appear to be more reasonable.

Transend has informed the AER that its assets are assigned on the basis of the standard asset life. Therefore the assets in this 5 year asset life category are reflective of this life. However, the AER notes that the majority of these assets are assigned a four year asset life by Transend which would make them perfect for the 'other – short life (4 years)' or 'transmission operation - short life (4 years)' asset classes. This would allow the longer life 'other – short life (9 years)' asset class to remain active with the longer lived short life assets such as motor vehicles, office furniture and voice communications.

The AER consider that these assets have been misclassified. Under NER clause 6A.6.3(b)(1) the AER is required to consider whether the depreciation profile reflects the economic life of the asset or category of assets. The 'other – short life (5 years)' asset class appears to contain a mixture of short life assets and long life assets. The AER's opinion is that all of the 'other - short life (5 years)' assets would be better represented in the 'other – short life (4 years)' asset category with the exception of the motor vehicle and voice communication assets. The motor vehicle and voice communication assets would remain in the 'other – short life (9 years)' asset category defined in the draft decision. This reclassification of assets is a better representation of the economic life of the assets as required under NER clause 6A.6.3(b)(1).

Removing the residual value of replaced assets

At the predetermination conference the MEG suggested that the AER should ensure that the depreciation of assets take account of replacement assets in the current regulatory period.[356] The AER has discussed Transend's methodology for depreciating replaced assets. Transend informed the AER that it was depreciating assets over their economic life and were not currently engaging an option for accelerated depreciation of replaced assets.

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355 Transend, *Revised revenue proposal*, op. cit. p.p. 18, 27.

356 MEG, *Submission to AER*, op. cit. p. 7.

The AER has reviewed Transend's methodology for depreciating replaced assets and consider that it is consistent with the requirements of NER clause 6A.6.3(b) of the NER.

Following the discussion of Transend's depreciation methodology, Transend further informed the AER it had made an error in calculating its disposals for the RFM. The AER has reviewed the corrected inputs for disposals and accepts that they are appropriate for the purposes of the RFM.

9.5.4 AER Conclusion

The AER confirms the asset classes defined in the draft decision, and rejects Transend's revised proposal to alter the 'other – short life (9 years)' category to become the 'other – short life (5 years)'. In doing this the AER has directed Transend to alter the composition of the 'other – short life (9 years)' category to move the computer assets in this category to the 'other – short life (4 years)' category.

9.6 AER assessment of building blocks

9.6.1 Opening asset base and roll forward

The NER requires that the roll forward of Transend'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 3, the AER has determined Transend's opening RAB value to be $951 million as at 1 July 2009. Based on this opening value, the AER has modelled Transend's RAB over the next regulatory control period as shown in table 9.4.

Table 9.4: AER's forecast roll forward of Transend's regulated asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	951.4	1067.0	1176.7	1223.8	1271.0
Net capital expenditure	168.2	170.0	104.0	112.0	114.5
Inflation adjustment on opening RAB	23.5	27.1	30.6	32.6	34.7
Straight-line depreciation	26.3	27.7	22.8	27.3	30.8
Closing RAB	1067.0	1176.7	1223.8	1271.0	1314.5

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

9.6.2 Forecast capital expenditure

As discussed in chapter 4, the AER has determined a forecast capex allowance for Transend of $607 million ($2008–09) during the next regulatory control period.

The annual nominal allowance is shown in table 9.4 and is used to calculate the forecast roll forward value of Transend's RAB.[357]

9.6.3 Depreciation

The AER, using the post-tax framework, 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 9.7 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) as discussed in section 9.5.

9.6.4 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 Transend's opening RAB for each year of the next regulatory control period.

As discussed in chapter 5, the nominal vanilla WACC of 8.80 per cent is based on a post-tax nominal return on equity of 10.30 per cent and a pre-tax nominal return on debt of 7.79 per cent. Table 9.7 shows the AER's return on capital allowance for this final decision.

9.6.5 Operating and maintenance expenditure

As discussed in chapter 6, the AER has determined a forecast opex allowance for Transend of $254 million ($2008–09) during the next regulatory control period. Table 9.7 shows the annual opex allowance, which equates to an average amount of $54.8 million per annum in nominal terms.

9.6.6 Operating and maintenance expenditure efficiency allowance

In the draft decision the AER determined an opex efficiency allowance did not exist for Transend over the next regulatory control period.[358] The AER has updated the calculation of annual opex efficiency savings with the most recent forecast of controllable opex for 2008–09 and the latest CPI data, at the time of its final decision. This calculation is set out in table 9.5 below.

[357] 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.

[358] AER, *Transend draft decision*, op. cit. p. 241-242.

Table 9.5: Calculation of annual opex efficiency savings ($m, 2008–09)

	2004 (Jan to Jun)	2004–05	2005–06	2006–07	2007–08	2008–09[a]	Total
Opex allowance	13.4	29.4	34.8	33.9	34.3	35.8	181.6
Less: network support	0.0	0.2	1.2	0.6	2.9	3.6	8.5
Less: equity/debt raising costs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Less: self insurance	0.0	0.0	0.0	0.1	0.3	1.0	1.4
Adjusted allowance	13.4	29.1	33.5	33.2	31.1	31.2	171.7
Less: controllable opex	13.0	29.2	36.9	37.7	45.6	49.7	212.2
Total efficiency	0.0	-0.1	-3.4	-4.4	-14.5	-18.5	-40.5
Average annual opex efficiency savings							0.0

(a) Actual CPI for 2008–09 (March to March) used.
Updated forecast figure.

9.6.7 Estimated taxes payable

Using the PTRM, the AER has modelled Transend's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than Transend'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 21.72 per cent for this final decision. Table 9.6 shows the AER's estimate of Transend's tax payments.

Table 9.6: AER's modelling of net tax allowance ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	Total
Tax payable	7.7	8.7	10.1	11.2	12.3	50.0
Value of imputation credits	-3.8	-4.4	-5.0	-5.6	-6.2	-25.0
Net tax allowance	3.8	4.4	5.0	5.6	6.2	25.0

Note: Total may not add up due to rounding.

9.7 AER determination—maximum allowed revenue

9.7.1 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 Transend that increases from $165 million in 2008–09 to $219 million in 2013–14 ($nominal). Table 9.7 shows the annual building block calculations.

Table 9.7: AER's final decision on annual building block revenue requirement ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Return on capital	83.7	96.2	108.7	115.8	123.3	527.6
Regulatory depreciation	26.3	27.7	22.8	27.3	30.8	134.8
Opex allowance	50.9	52.9	53.8	57.7	58.8	274.0
Opex efficiency (glide path) allowance[a]	0.0	0.0	0.0	0.0	0.0	0.0
Net tax allowance	3.8	4.4	5.0	5.6	6.2	25.0
Annual building block revenue requirement (unsmoothed)	164.7	181.1	190.3	206.5	219.0	961.5

(a) An allowance for opex efficiency resulting in the current regulatory period.

9.7.2 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 $743 million. Based on this NPV amount, the AER has determined a nominal expected MAR (smoothed) for Transend that increases from $165 million in 2008–09 to $222 million in 2013–14, as shown in table 9.8. The MAR for Transend over the next regulatory control period is $962 million. Transend's MAR for the next regulatory control period is to be calculated using the formula described in draft decision and part 1 of Transend's transmission determination.

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 –5.19 per cent in subsequent years, as shown in table 9.8. The AER considers that the X factor profile results in an expected MAR in the final year of the next regulatory control period that is as close as reasonably possible 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. The AER's revenue determination for Transend is set out in part 1of the transmission determination.

Table 9.8: AER's final decision on the maximum allowed revenue ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
MAR (smoothed)	164.7	177.5	191.4	206.3	222.4	962.3
X factor	–[a]	–5.19 %	–5.19 %	–5.19%	–5.19 %	–

(a) The MAR for 2008–09 is set as $144.6 million and Transend is not required to apply an X factor. The MAR in the first year of the next regulatory control period (2009–10) is around 11.1 per cent higher than the MAR in the final year of the current regulatory period (2008–09).

The average revenue increase of 9.0 per cent per annum (nominal) over the next regulatory control period consists of an initial increase of 13.9 per cent from 2008–09 to 2009–10 and a subsequent average annual increase of 7.8 per cent during the remainder of the next regulatory control period.

In real terms ($2008–09), the average revenue increase of 6.4 per cent per annum over the next regulatory control period consists of an initial increase of 11.1 per cent from 2008–09 to 2009–10 and a subsequent average annual increase of 5.2 per cent during the remainder of the next regulatory control period.

The AER in its draft decision reported the average revenue increase in real and nominal average rate terms from 2008-09 to 2013-14. That is, 9.0 per cent, in this final decision. The AER considers that this figure provides a general overview of the increase in prices for Transend for the next period. The EUAA submission raised the issue of why revenues for Transend have risen by a little under 60 per cent between current and the next regulatory period while prices have only risen by 30 per cent. This is the result of the relative growth rates of revenue and energy interacting to erode the price increase.

In simplified algebraic terms, this relationship can be expressed as:

$$Revenue = Price \times Quantity$$

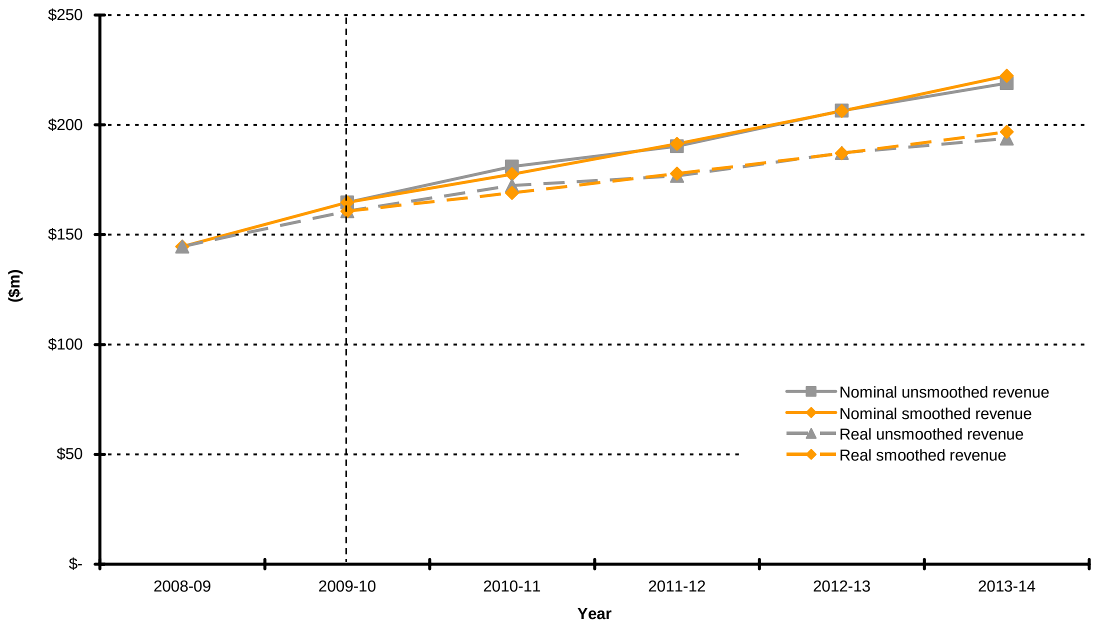
As the AER sets the revenue it must be held constant so if the quantity Transend transports through its network doubles price will half:

$$Revenue = (\frac{1}{2} \times Price) \times (2 \times Quantity)$$

The AER's calculation takes into account changes in both revenue and energy during the regulatory control period.

Figure 9.1 shows the revenue path allowed in this final decision (both smoothed and unsmoothed) in nominal and real terms.

Figure 9.1: Revenue path from 2009–10 to 2013–14 ($m)



9.8 Average transmission charges

Transend's MAR for the next regulatory control period is established through a building block approach. While the AER assesses Transend's proposed pricing methodology, actual transmission charges established at particular connection points are not approved by the AER. Transend establishes its transmission charges in accordance with its approved pricing methodology and the NER.

The effect of the AER's final decision on average transmission charges can be estimated by taking the annual MAR and dividing it by forecast annual energy delivered in Tasmania.[359] Based on this approach, the AER estimates that this final decision will result in a 6.0 per cent per annum (nominal) increase in average transmission charges over the next regulatory control period or an increase of 3.5 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 Tasmania, which is forecast to increase on average by 1.9 per cent per annum over the next regulatory control period.[360] The increase in average transmission charges is primarily because of:

- a higher opening RAB than was forecast in the 2003 revenue cap decision
- the need to replace and maintain ageing assets

359 The forecast energy delivered (customer sales) figures were obtained from Transend 2008 Annual Planning Report.

360 Based on Winter 10 per cent probability of exceedence peak demand (native demand) between 2009–10 and 2013–14. Transend 2008 Annual Planning Report, p. 39.

- the need for increased capex associated with the new reliability standards specified in the Tasmanian Electricity Code (TEC)
- 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.

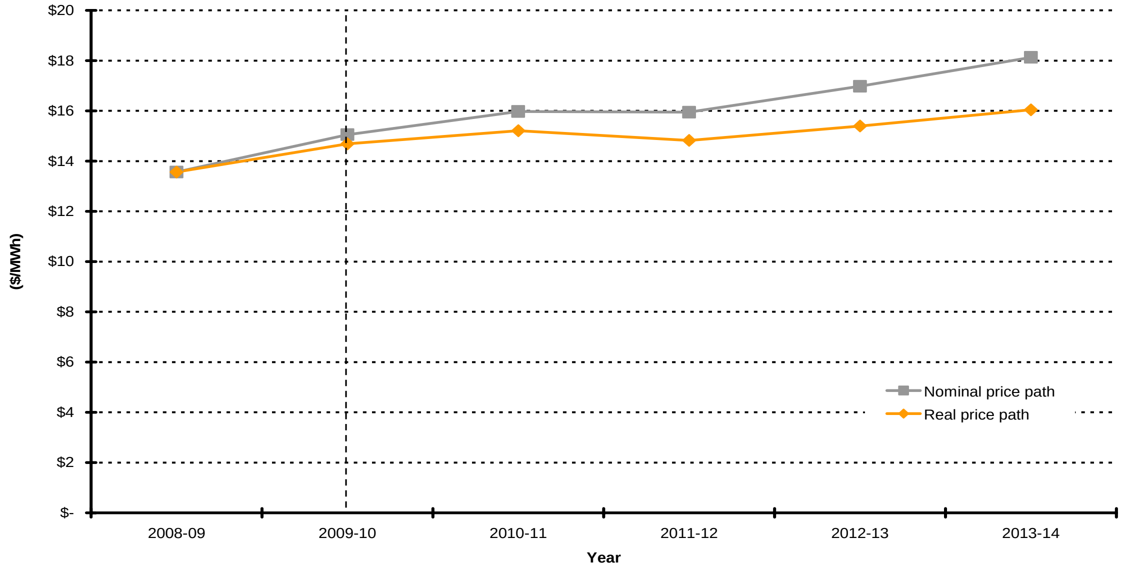
Transmission charges represent approximately 12 per cent on average of end user electricity charges in Tasmania. The AER estimates, in nominal terms, that the rise in average transmission charges under this final decision will result in an increase to the average medium residential customer's annual bill of $1400 by approximately $18.44 in the first year and $9.52 for each following year of the regulatory period. This equates to approximately $11.31 or 6.0 per cent per year.[361]

In real terms, the AER estimates that the rise in average transmission charges under this final decision will result in an increase to the average medium residential customer's annual bill of $1400 by approximately $13.94 in the first year and $4.19 for each following year of the regulatory period. This equates to approximately $6.14 or 3.4 per cent per year.

Figure 9.2 shows the resulting average price path of this final decision during the next regulatory period compared with the average price for the final two years of the current regulatory period in nominal and real terms ($2008–09). The average transmission charge in 2008–09 is $13.56 per MWh. The nominal average transmission charge is forecast to increase from approximately $15.05 per MWh in 2009–10 to $18.13 per MWh in 2013–14. The real average transmission charge is forecast to increase from approximately $14.69 per MWh in 2009–10 to $16.04 per MWh in 2013–14.

361 Interpolated from Transend revenue proposal, page 6, a 3 per cent price increase, in real terms, caused by a $42 rise in price under the Transend proposal means the average end user electricity charge is $1400.

Figure 9.2: Price path from 2009–10 to 2013–14 ($/MWh)



10 Negotiating framework for negotiated transmission services

10.1 Introduction

The AER's transmission determination for Transend must include a determination relating to Transend's negotiating framework for negotiated transmission services. The negotiating framework specifies the procedure that a transmission network service provider (TNSP) must follow when negotiating terms and conditions of access with an applicant seeking a negotiated transmission service. Where an access dispute occurs a commercial arbitrator must have regard to the negotiating framework. There are three types of negotiated transmission services that a service applicant may request and negotiate with a TNSP:

- connection services (which might include entry, exit and TNSP to market network service providers connection services)
- use of system services supplied by the shared transmission network that exceed or are below the network's specified performance standard under any legislation of a participating jurisdiction
- use of system services relating to augmentations or extensions required to be undertaken on a transmission network as described in clause 5.4A of the NER.

The negotiating framework relates only to negotiated transmission services. The pricing of prescribed transmission services is covered by the pricing methodology discussed in Chapter 12 of this final decision.

10.2 AER draft decision

The AER assessed Transend's proposed negotiating framework against the NER requirements. The AER determined that Transend's proposed negotiating framework complied with clause 6A.9.5(c) of the NER.

10.3 Transend revised proposal

Transend did not address the negotiating framework in its January 2009 revised revenue proposal.

10.4 Submissions

The AER received one submission relating to the negotiating framework.

Hydro Tasmania stated that Transend's terms of credit are "very restrictive, essentially accepting no counterparty credit risk"[362] and should be amended to be in line with normal commercial and industry practice.[363]

362 Hydro Tasmania, *Re: Transend's 2009-2014 draft revenue determination*, 23 February 2009, p.1

Hydro Tasmania also stated that the proposed negotiating framework does not explicitly address the issue of risk allocation between Transend and the applicant in its proposed negotiating framework.[364]

Given Transend's negotiating position as a monopoly service provider, it is important that both credit risk and allocation of risk are dealt with in the negotiating framework, to avoid any perception of unreasonableness during a negotiation of terms.

Hydro Tasmania expressed its concern that unless the AER directs otherwise, Transend may continue to apply an unreasonable approach for the whole of the 2009-14 regulatory control period. This will potentially inhibit optimal development of the network to support increased generation and new connections in Tasmania.[365]

10.5 Issues and Considerations

The AER has considered the issues discussed in Hydro Tasmania's submission.

The AER has assessed Transend's proposed negotiating framework as required by clause 6A.14.3(f) of the NER. As stated in the draft decision, the AER approved Transend's proposed negotiating framework as it is compliant with the requirements of clause 6A.9.5(c).[366] The AER has not changed its position on this matter.

Negotiated transmission service applicants, including Hydro Tasmania, who dispute the terms and conditions of access for provision of negotiated transmission services, including credit risk terms, can deal with such disputes in accordance with Part K of Chapter 6A of the NER, as stated in clause 11 of Transend's proposed negotiating framework.[367] This complies with clause 6A.9.5(c)(6) of the NER.

With respect to the allocation of risk, Hydro Tasmania refers to a criterion in the AER's proposed negotiated services criteria for Transend.[368] As noted on page 253 of the draft decision, TNSPs are not required to submit criteria (regarding the negotiated transmission services criteria) to the AER. There is also no requirement under either the AER's submission guidelines[369] or the NER to address the allocation of risk issue in the negotiating framework. It is considered that risk allocation terms are issues that Transend would discuss with applicants on a case by case basis. As with credit risk terms, disputes regarding allocation of risk in the provision of negotiated transmission services can be dealt with in accordance with Part K of Chapter 6A of the NER.

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363 ibid.

364 ibid., p.2.

365 ibid.

366 AER, *Transend transmission determination 2008–09 to 2013–14: Draft decision*, 21 November 2008, p.252.

367 Transend, *Proposed negotiating framework*, May 2008, p.8.

368 AER, *Proposed negotiated transmission services criteria for Transend*, June 2008, p.6.

369 AER, *Electricity transmission network service providers submission guidelines*, September 2007.

10.6 AER conclusion

The proposed negotiating framework will apply to Transend for the regulatory control period 1 July 2009 to 30 June 2014. The AER notes that it can request Transend to resubmit its negotiating framework at any time, and would do so if the operation of Transend’s negotiating framework does not result in effective negotiation of negotiated transmission services.

11 Negotiated transmission service criteria

11.1 Introduction

The NER requires the AER to include in a transmission determination the negotiated transmission service criteria (negotiating criteria) that will apply to a transmission network service provider (TNSP) for a regulatory control period.[370] The negotiating criteria are to be used by the TNSP in negotiating the terms and conditions, including price and any access charges, for accessing a negotiated transmission service. In the event of a dispute about the terms and conditions of access or any charges to be paid to the TNSP, a commercial arbitrator must consider the negotiating criteria when making a decision under Part K of the NER.

11.2 AER draft decision

As required by the NER, the AER determined the negotiated transmission service criteria that gave effect to and were consistent with the negotiated transmission service principles set out in clause 6A.9.1. The AER accepted Transend's negotiated transmission service criteria in the draft decision.

11.3 Transend revised proposal

Transend did not address the negotiating transmission service criteria in its January 2009 revised revenue proposal.

11.4 Submissions

The AER did not receive any submissions on the proposed negotiating criteria.

11.5 AER conclusion

The AER confirms the draft decision to accept the negotiated transmission service criteria, as set out in part 3 of the transmission determination, will apply to Transend for the regulatory control period 1 July 2009 to 30 June 2014.

[370] NER, clause 6A.2.2(3).

12 Pricing methodology

12.1 Introduction

This chapter sets out the AER's consideration of Transend's revised proposed pricing methodology for the regulatory control period 1 July 2009 to 30 June 2014 submitted on 14 January 2009.

12.2 AER draft decision

Transend submitted its proposed pricing methodology to the AER on 31 May 2008.

In the draft decision the AER assessed Transend's proposed pricing methodology against the guidelines. While the proposed pricing methodology largely complied with the guidelines, some portions did not meet the guidelines' requirements. Consequently, the AER did not approve Transend's proposed pricing methodology in the draft decision and Transend was required to submit a revised proposed pricing methodology by 14 January 2009.

12.3 Transend revised proposed pricing methodology

On 14 January 2009 Transend submitted its revised proposed pricing methodology to the AER. Transend stated that its revised proposed pricing methodology fulfils its obligations under the NER to prepare a pricing methodology for prescribed transmission services.[371]

Transend's revised proposed pricing methodology included several amendments namely:

- the treatment of radial lines
- locational component prices for prescribed TUOS services
- editorial changes and specifying the points in the transmission network where costs will be allocated and prices determined.

The remainder of the proposed pricing methodology remained unchanged from the draft decision.

12.4 Submissions

The AER did not receive any submissions on Transend's revised proposed pricing methodology.

12.5 Issues and AER considerations

Transend has made the amendments required by the AER in its draft decision of 21 November 2008.

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[371] Transend, *Revised proposed pricing methodology*, 14 January 2009, p.6.

Transend has made no further changes to its revised proposed pricing methodology other than those specified in the draft decision. The draft decision required further drafting in the following areas of Transend's proposed pricing methodology.

12.5.1 Treatment of Radial Lines

AER draft decision

The draft decision required Transend to amend section 7.3 and appendix 2 of the proposed pricing methodology such that costs related to radial lines connecting generator and load are attributed in accordance with the pricing principles as set out in rule 6A.23 of the NER.[372]

Transend revised proposal

In its revised revenue proposal, Transend stated that it has amended the relevant sections "so that costs related to radial lines connecting generator and load are attributed according to the pricing principles as set out in rule 6A.23".[373]

Transend also deals with the treatment of radial lines connecting generator and load in section 4.6.8 of the revised proposed pricing methodology. Transend stated that "Chapter 6A of the Rules classifies these assets as connection assets" and the cost of these assets will be recovered from prescribed connection services.[374] In keeping with the changes that have been made to the revised revenue proposal, Transend is to state its compliance with rule 6A.23 of the NER in section 4.6.8 of the revised proposed pricing methodology.

AER considerations

The AER accepts Transend's revised proposed pricing methodology subject to the amendment to section 4.6.8 as described above.

12.5.2 Locational component prices for prescribed TUOS services

AER draft decision

The draft decision required Transend to amend the proposed pricing methodology such that the measure of demand used to calculate the prescribed TUOS service locational price is consistent with the measure of demand used to calculate the prescribed TUOS service locational charge. This would minimise the distortion of prices that was possible under the proposed pricing methodology.[375]

Transend revised proposal

In the revised proposed pricing methodology, Transend stated that it will use prevailing contract agreed maximum demand as the measure of demand to calculate the prescribed TUOS services locational prices. During each billing period, it will

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372 AER, *Transend transmission determination 2008–09 to 2013–14: Draft decision*, 21 November 2008, p.261.

373 Transend, *Transend transmission revised revenue proposal for the regulatory control period 1 July 2009 to 30 June 2014*, 14 January 2009, p.77.

374 Transend, *Revised proposed pricing methodology*, 14 January 2009, p.12.

375 AER, *Transend draft decision*, op. cit. p.259.

then determine prescribed TUOS service locational charges by "multiplying the locational price applicable to each connection point by the relevant contract agreed maximum demand."[376]

AER considerations

The AER considers that this amendment is consistent with the requirement in the draft decision and accepts this amendment to the pricing methodology.

12.5.3 Amendments to Appendix 2

Revised revenue proposal

Transend subsequently informed the AER that appendix 2 of the revised proposed pricing methodology was drafted according to the requirements of the NER prior to the amended clause 11.6.11, which was made on 29 January 2009 and commenced operation on 13 February 2009.[377] However, Transend's pricing methodology takes effect after the AER's transmission determination has been made when the amended clause 11.6.11 is in effect.

Therefore, Transend is to amend appendix 2 of the revised proposed pricing methodology such that it is compliant with the amended clause 11.6.11.

AER considerations

The AER accepts Transend's revised proposed pricing methodology subject to amendments to appendix 2 such that it is compliant with the amended clause 11.6.11.

12.6 AER conclusion

The AER has considered Transend's revised proposed pricing methodology submitted on 14 January 2009, and request that Transend make several changes to improve the methodology's clarity and to ensure it complies with the guidelines. The AER is satisfied that Transend's amended revised proposed pricing methodology complies with the NER and the guidelines and therefore approves it, subject to the amendments required in sections 12.5.1 and 12.5.3 of this final decision.

376 Transend, *Revised proposed pricing methodology*, op. cit. p.25.

377 See AEMC, *National electricity amendment (cost allocation arrangements for transmission services) rule 2009 no. 3.*

Appendix A: Cost Escalators

This appendix presents the AER's final assessment of the methodology and data sources for the proposed materials and labour cost escalators. The values of the cost escalators have been updated to reflect the latest available information.

A.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. 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 profession 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). 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. 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
- electricity, gas and water (EGW) sector labour costs
- land/easement costs.

Other inputs (such as steel) were escalated at CPI.

A.2 Draft decision

In assessing the escalators recommended by the Competition Economist Group (CEG) and used by the Transend, the AER considered that its conclusions from the recent ElectraNet decision were still applicable with respect to the methodology used for estimating each of the cost escalators (i.e. copper, aluminium and crude oil). In most cases, the AER considered that CEG had not presented any new compelling evidence that justified a departure from the approach previously accepted by the AER.[378]

At a fundamental level, the AER was concerned with the additional cost factors—producer margins, producer labour costs, indirect general labour —that did not meet the underlying objective for inclusion in forecast costs under clause 6A.5.7(c) of the NER.[379]

In particular, the AER considered that given the inherent uncertainties around the existence of and estimation of real movements in these cost factors, departures from CPI were not warranted. The AER also noted that it accepted that such costs were likely to be included in base (unit) cost estimates but questioned the extent to which real growth were expected and whether it could be forecast on a reasonable basis.[380]

In the draft decision the AER stated that it would update its escalators closer to the time of the release of its final decision.[381]

A.3 Revised regulatory proposals

Transend did not accept the materials cost escalators applied by the AER in the draft decision. Transend engaged CEG[382] to review the draft decision and, based on that advice, determined that while the AER's approach was largely reasonable, they had concerns with:[383]

- the AER's modelling, principally timing and the application of lags
- the AER's proposed approach to updating labour cost escalation factors.

Transend accepted the cost escalator for land specified in the draft decision. Revised escalators were, however, proposed for the majority of the other cost escalators.

378 AER, *Transend draft decision*, op. cit. pp. 355–391.
379 ibid., p. 357.
380 ibid., p. 357.
381 ibid., p. 357.
382 CEG, *Escalations affecting expenditure forecasts: A report for NSW and Tasmanian electricity businesses*, January 2009.
383 CEG, *Escalations affecting expenditure forecasts*, p. 2.

A.4 Non-labour cost escalators—aluminium, copper, steel and crude oil

A.4.1 Draft decision

Taking into account the methodology it had developed for the ElectraNet decision[384], the AER rejected Transend's materials cost escalators.[385] The AER applied the materials cost escalators set out in table A1 for the next regulatory control period.

Table A1 AER's draft conclusions on real aluminium, copper, crude oil and steel cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–6.3	–7.0	7.5	9.3	–0.8	–1.3	–1.6
Copper	–6.3	–13.5	0.3	1.4	–5.6	–6.3	–7.0
Steel	53.8	–3.7	0.6	–3.4	–2.5	–3.0	–3.4
Crude oil	43.5	–13.4	1.5	1.7	0.1	–0.6	–0.1

Source: AER, *Draft decision*, pp. 376, 379,381.

The AER forecast aluminium and copper prices by using London Metals Exchange (LME) futures prices up to 2010 and then long–term Consensus Economics forecast (7.5 years). It interpolated between the two data sources to obtain a data series that covered the next regulatory control period. Since all aluminium and copper prices from LME and Consensus Economics were in nominal US dollar (USD) terms, the projections were also converted into nominal Australian dollars (AUD)[386]—see section A.9.

The AER used hot rolled coiled steel prices from Bloomberg for historical steel prices from Europe and the United States and then Consensus Economics forecasts for corresponding future prices. These steel prices were then:[387]

- adjusted from short to metric tonnes for US steel prices
- averaged and adjusted to Australian dollar terms using a methodology consistent with that adopted for aluminium and copper prices.

The AER forecast the real cost escalation for oil using historical average world oil prices sourced from the United States Department of Energy and Bloomberg forecast contract prices. The prices were then averaged and adjusted to Australian dollar terms using a methodology consistent with that adopted for aluminium and copper prices.

384 AER, *Final decision: ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008.

385 AER, *Transend draft decision*, op. cit. pp. 369–391.

386 ibid., pp. 372–375.

387 ibid., pp. 376–379.

Due to the high volatility of the data, the AER used a centred moving average to account for prices for each month.[388]

In the draft decision, the AER also considered that it was not appropriate to apply a lag to commodity input prices in the process of escalating materials component of capex.[389]

A.4.2 Revised regulatory proposals

Transend did not accept the materials cost escalators applied by the AER in the draft decision and engaged CEG to review the draft decision. CEG concluded that while the AER's approach was reasonable, issues around the base period timing and lags adjustment had not been appropriately taken into account.[390]

CEG noted that the AER's decision to use June on June escalation factors for materials costs assumed that all objects were costed and purchased in June rather than spread over the 12 months of a financial year. It also suggested that base period prices should be escalated to reflect the change in average prices from the base period to the 12 months to June of each future year.[391]

Transend accepted CEG's findings and proposed revised escalators for materials—see tables A2.

Table A2: Transend revised real aluminium, copper, steel and crude oil cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	-6.2	6.9	5.9	7.4	-0.1	-0.9	-1.2
Copper	-9.6	-13.7	0.0	14.9	-4.4	-6.2	-6.6
Steel	47.5	1.8	-0.5	-1.2	-4.6	-4.9	-5.2
Crude oil	36.7	-12.5	9.7	4.9	1.3	-0.4	-1.5

Source: CEG, *Escalators affecting expenditure forecasts*, p. 23.

A.4.3 Submissions

The Energy Users Association of Australia (EUAA) noted a change in economic outlook and falls in materials costs both domestically and globally and that the RBA's Index of Commodity Prices showed a decrease in commodity prices of 4 per cent in December 2008.[392] It welcomed the AER's decision to review input costs closer to the final decision and noted that it expected that this would result in significant reductions in capex.[393]

388 AER, *Transend draft decision*, op. cit. pp. 379–381.
389 ibid., pp. 388–391.
390 CEG, *Escalations affecting expenditure forecasts*, pp. 3–7, 17–19.
391 ibid., pp. 3–6.
392 EUAA, p. 16.
393 ibid., p. 17.

Nystar noted that the forecast input cost escalators for materials are too optimistic, particularly for the first half of the regulatory control period. Transend is flawed when they purport to not focus exclusively on the latest commodity price data to forecast the cost of projects over the forthcoming period. Commodity prices will most likely be constrained by poor industrial production for quite some time.[394]

A.4.4 AER considerations

Base period adjustments

The AER considers that CEG's recommendation to adopt a 12 month averaging period for materials escalators for each financial year of the next regulatory control period is reasonable.[395] It considers this is appropriate as it:

- removes potential price distortions that may occur during any single month
- recognises that all equipment may be costed and purchased continuously throughout the next regulatory control period.

The AER considers that the use of this approach will permit the development of a robust forecast that reflects all materials cost data for each year.

CEG was also concerned with the AER's assumption that all equipment was costed and purchased in June rather than in the time period in which Transend's base costs were calculated.

The AER considers there is merit in making an adjustment to reflect base period prices, as this allows for more accurate cost escalation to be determined. It has adjusted the base period for Transend to reflect the base cost period of June 2007 for the next regulatory control period.

Adjustment lag

In the draft decision, the AER examined the material provided by Transend and concluded that there was not sufficient evidence to support the application of a lag between commodity price changes for materials and equipment costs.[396] Transend accepted the AER's draft decision to exclude lags in its revised proposal.[397]

Other issues

The AER identified an error in the draft decision model for the calculation of cost escalators for copper and aluminium. In the draft decision, the AER stated that the forecast monthly copper and aluminium prices were determined by interpolating between the LME spot price, the 3 month LME contract price, the 15 month LME contract price, the 27 month LME contract price and the most recent long-term Consensus Economics forecast price. This process was not correctly reflected in the model and this error has been addressed in this final decision.

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394 Nyrstar, p.3

395 This averaging period is centred on December as proposed by CEG as it is reflective of price movements over the entire year.

396 AER, *Transend draft decision*, op. cit. p.391.

397 Transend, *Revised revenue proposal*, op. cit. p 34

The AER's conclusions on materials cost escalations are set out in table A3.

Table A3: AER's conclusions on Transend's real aluminium, copper, steel and crude oil cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	-8.5	-17.3	-14.1	9.1	10.5	10.9	9.3
Copper	-4.3	-27.9	-10.8	2.1	2.5	2.3	2.0
Steel	12.1	16.3	-15.3	7.2	5.2	1.0	0.8
Crude oil	31.2	-18.3	-5.2	10.2	5.7	2.2	1.3

A.5 EGW wages and general wages

A.5.1 AER draft decision

In the draft decision, the AER engaged Econtech to provide advice on labour cost growth forecasts in Tasmania. The AER was satisfied that Econtech's wage growth forecasts for the electricity, gas and water (EGW) sector were robust and applied these forecasts for the next regulatory control period. In applying Econtech's forecasts, the AER did not accept Transend's proposal, which was based on advice from the Competition Economists Group (CEG), to apply an average of Econtech (published in 2007) and Macromonitor EGW labour costs growth forecasts.[398]

The AER considered the averaging methodology adopted by CEG was not appropriate because the Macromonitor and Econtech EGW labour costs growth forecasts were not comparable and averaging the two forecasts was likely to produce unreliable labour cost escalation forecasts. In addition, the AER did not consider it appropriate to rely on the forecasts presented by Macromonitor because there was no description of the methodology used to forecast EGW wages or productivity adjustments for the AER to make an assessment.[399]

The AER accepted that Econtech's general labour cost growth forecasts are appropriate to escalate direct labour costs (i.e. other than EGW) incurred by Transend. The AER, however, did not accept the general wage forecasts applied by Transend, sourced from Econtech's 2007 report, due to the change in economic conditions that occurred since the report was released. The AER considered Econtech's latest general wage forecasts were more appropriate as they took account of more recent data, and were based on a more reliable forecasting methodology and robust data source.[400]

The AER's draft conclusions for Transend's EGW and general labour forecasts are set out in table A.4.

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398 AER, *Transend draft decision*, op. cit. p.176.
399 ibid., p. 366.
400 Econtech, *Labour Costs Growth Forecasts*, [date 1st use], p. 38 and AER, *Transend draft decision*, p. 366.

Table A4: AER's draft conclusions on Transend's EGW and general labour (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
EGW wages/ EBA	0.4	2.0	2.9	2.8	2.5	2.4	1.9	2.5
General labour	0.6	1.0	1.1	0.7	0.7	0.8	0.6	0.8

Source: AER, *Transend draft decision*, pp. 176, 363.

A.5.2 Revised revenue proposal

Transend did not accept the EGW wages and general labour escalators applied by the AER in the draft decision. It re-engaged CEG to review the draft decision. CEG considered that while the AER's approach was largely reasonable, it had concerns with the timing calculations applied in the draft decision. Issues raised by CEG are discussed below.

AER analysis of the Macromonitor forecasts

CEG did not accept the AER's reasons for rejecting the Macromonitor labour cost forecasts proposed by Transend.

CEG advised there were three Macromonitor reports which it relied upon, and considered that it had sufficiently described the basis on which Macromonitor derived the labour cost forecasts.[401] These reports include:

- *Forecasts of Cost Indicators for the Electricity Transmission Sector - Tasmania, February 2008*
- *Forecasts of Cost Indicators for the Electricity Transmission Sector - Forecasting Methodology, September 2008*
- *Australian Construction Outlook 2008, November 2007.*

CEG considered the only major difference between Macromonitor and Econtech's forecasts to be the application of Econtech's econometric model of the Australian economy to derive its forecast. CEG stated that econometric models did not provide superior forecasts and provided a number of quotes from academics to support this view.[402]

CEG stated Econtech has made clear it did not adjust its labour cost forecasts for productivity.[403] CEG also considered that the AER, in accepting Econtech's forecasts, has implicitly accepted that forecast wages growth should not be adjusted for productivity growth.

401 CEG, *Escalators affecting expenditure forecasts*, op. cit. p. 27.
402 ibid., pp. 28–29.
403 ibid., p. 33.

CEG did, however, acknowledge the professional expertise of Econtech and accepted the use of Econtech's forecasts in the draft decision as reasonable. CEG recommended Transend adopt the AER's forecasts in its revised revenue proposal.[404]

Application of EGW wage and general labour escalators

CEG raised issues with applying updated Econtech EGW and general labour escalators after Transend had lodged its revised revenue proposal. CEG stated that in the case of wage forecasts, there is a degree of judgement involved in assessing the variables that make up labour cost forecasts. CEG considered that if the AER was to seek an update from Econtech for EGW labour cost growth rates, it would be described as re-doing a forecast, rather than updating a forecast in accordance with an agreed methodology. CEG stated that the AER should consult with the businesses if further updates were recommended by Econtech.[405]

Timing

CEG raised a number of concerns with the timing calculations applied in the draft decision. Specifically:[406]

- Econtech's forecasts for EGW and general wages growth were in financial year average terms, and not in June to June terms
- EBA were not correctly timed to interpolate to EGW rates, resulting in the model double counting inflation for some years.

As a result, CEG proposed revised EGW wages and general labour escalators, based on the Econtech forecasts applied by the AER in its draft decision, to address these concerns.

A.5.3 Submissions

The EUAA stated that due to the worsening economic climate, wage cost pressures had fallen. Further the EUAA noted: [407]

- the RBA had revised its Wage Price Index from 4 per cent in 2008–09 to 3.5 per cent in 2009–10
- the RBA expects the Wage Price Index to remain static at 4 per cent for 2010–11 to 2011–12.

The EUAA also submitted:[408]

- that the AER should refresh its labour cost escalation assumptions in light of the recent economic collapse and global downturn

[404] CEG, *Escalators affecting expenditure forecasts*, op. cit. p. 13.
[405] ibid.,
[406] ibid., pp. 7–12.
[407] EUAA, *Submission to Australian Energy Regulator's draft decision & revised DNSP proposals – Review of the regulatory proposals by the NSW electricity distributors*
[408] EUAA, *EUA submission to AER on the draft decision on Transend's regulated revenue for the 2009 to 2014 regulatory period*, pp. 13&17

- expected real wage increases should ultimately be discounted for normal increases in labour productivity
- that the past commodity boom and labour shortages are no longer realistic assumptions for the next regulatory control period
- cost escalation factors and labour costs be reviewed and updated for the changed economic circumstances that have resulted in the past 12 months since TransGrid's capex planning assumptions were developed.

Powerlink noted the AER's adoption of Econtech's labour forecasts and considered it reasonable for the AER to consult more widely on the escalators prior to finalising its determination.[409]

Major Employer Group (MEG) submitted that Transend's claim that it continues to operate in a tight market for skilled labour contradicts the current economic environment in which unemployment is expected to rise substantially over the next 12 months.

Nyrstar provided a confidential submission to the AER with respect to Transend's revised revenue proposal.[410]

A.5.4 Consultant review

The AER re-engaged Econtech to provide an update on its wage forecasts for the EGW sectors in NSW, ACT, Tasmania and nationally.[411] Econtech's EGW labour cost growth rates are shown in table A5.

Table A5: Econtech's real labour escalation rates for the EGW sector in Tasmania and Australia (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Tasmania	-2.9	-0.8	2.4	2.7	1.3	0.6	-0.3
Australia	-0.7	-1.0	2.8	3.1	2.1	1.5	0.5

Source: Econtech, *Updated labour cost growth forecasts*, 25 March 2009, pp 29, 31.

Econtech determined these forecasts using an updated version of its labour cost model (LCM).[412] In particular, the forecasts provided by Econtech reflect the following factors:[413]

- an enhanced approach to labour cost forecasting, which was initially used in the September 2008 report

409 Powerlink, *Submission on Transend draft decision*. 18 February 2009, p. 2.
410 Nystar Australia Pty Ltd, *Submission to Transend's revised revenue proposa*l (confidential), 17 February 2009.
411 Econtech, *Updated labour cost growth forecasts for the AER*, 25 March 2009
412 This model was purpose built by Econtech for its report to the AER in August 2007.
413 Econtech, *Updated labour cost growth forecasts*, op. cit. p. 4.

- national accounts data up to December 2008 (published by the Australian Bureau of Statistics (ABS))
- average weekly earnings data up to November 2008 (obtained by request from the ABS)
- the Federal Government stimulus package announced in December 2008 and February 2009.

Econtech noted the revisions to the ABS average weekly earnings data series for the August 1996 to May 2008 period, as a result of the ABS quantifying the extent of mis-reporting with data providers.[414]

Econtech acknowledged that its updated labour cost growth forecasts differ considerably to its labour forecasts, published in September 2008. Econtech linked the immediate slowing of labour cost growth projections with the deteriorating global financial situation and anticipation that Australia will slip into recession in 2009. Econtech further noted deteriorating consumer and business confidence, declining dwelling investment, credit markets remaining frozen and expected increases in unemployment rates as contributing factors to Australia's forecast declining economic performance.[415]

Econtech considered that the updated short to medium–term labour growth forecasts will vary the most compared with previous projections in September 2008, as a result of downward revisions to business investment for the period 2008–09 to 2010–2011 due to the current global financial crisis. Econtech further considered that the longer term labour growth projections are largely unaffected due to its anticipation that Australia will begin to recover from the recession in late 2010.[416]

Econtech observed that a recent crash in commodity prices has had implications for labour demand in the mining industry and consequently, wages growth in that sector. This has had a flow on effect for EGW labour forecasts, where competition for workers with similar skills—namely, electricians and electrical and other engineers from the mining and construction industries—has slowed.[417] This slowing in labour demand has resulted in slowing wage growth in the EGW sector, which has fallen (compared to Econtech's September 2008 forecasts) particularly in the immediate period to 2009–10.[418] This is consistent with the inverse observations by Econtech relating to increases in above average wages growth, due to the recent mining and construction boom, which were exacerbated by a skills shortage and businesses being forced to offer higher wages to attract skilled workers.[419]

At the national level, the projected growth rate for the EGW sector is expected to perform better relative to the mining and construction industries. This outcome is consistent with Econtech's observations in its September 2008 report, which noted

414 ABS, *Information paper: revisions to average weekly earnings series*, August 2008, Cat. No. 6302.0.553.001, November 2008.
415 Econtech, *Updated labour cost growth forecasts*, op. cit. pp. 7–8.
416 ibid., pp. 8–9.
417 ibid., p. 9.
418 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, 19 September 2008, p. 25.
419 ibid., p. 23.

that given the essential nature of utility services, they have a greater imperative to attract and maintain skilled workers.[420]

Econtech made the following observations on the utility sector in Tasmania:[421]

- forecast wages across all sectors/industries exhibit weak growth in the immediate future, given falls in business investment and demand which are expected to reduce demand for utilities workers
- EGW wages, despite exhibiting depressed growth in the immediate future, is expected to accelerate from 2011–12, in line with recovery of general economic conditions
- the forecast EGW average annual real growth rate (at 2.2 per cent) is expected to be higher than the all–industry average (at 0.4 per cent) for the next regulatory control period.

As part of its updated EGW forecasts, Econtech also provided an update on general wage forecasts for all industries for Tasmania.[422] Econtech's updated general labour cost growth rates are shown in table A 6.

Table A6: Econtech's real general labour escalation rates for Tasmania (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Tasmania	–2.9	–1.9	0.0	0.5	–0.7	–1.0	–1.5

Source: Econtech, *Updated labour cost growth forecasts for the AER*, 25 March 2009, p 28.

As part of updating its forecasts, Econtech also undertook a review of CEG's report submitted in January 2009, which formed part of Transend's revised revenue proposal.[423]

A.5.5 AER considerations

Econtech and Macromonitor forecasts

In the draft decision, the AER reviewed the three Macromonitor reports referred to by CEG. The AER maintains its view and is not satisfied that they provide sufficient explanation surrounding the basis of the model used to derive Macromonitor's forecasts. The AER notes Macromonitor's discussion of the drivers of unit costs but also notes Macromonitor did not outline any determining factors or key macro-economic variables that it employed to calculate its EGW labour cost growth forecasts.[424] The AER maintains that the Macromonitor reports do not contain sufficient description of the methodology used to forecast wage growth.

420 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, p. 23; and Econtech, *Updated labour cost growth forecasts*, p. 9.
421 Econtech, *Updated labour cost growth*, op. cit. pp. 11–12.
422 ibid., p.28.
423 ibid.
424 Macromonitor, *Forecasts of cost indicators for the electricity transmission sector - New South Wales and Tasmania*, p. 3.

The AER notes that Econtech's September 2008 report considered the Macromonitor report did not contain any description of the methodology used to forecast wages growth. Econtech considered that the extent to which Macromonitor's forecasts for EGW wages are consistent with the outlook for broad macro-economic factors nationally, and across industries and states is unclear.[425] Econtech found that upon reviewing CEG's revised escalator report, it remains difficult to assess the forecast results provided by Macromonitor as no new information pertaining to the methodology has been provided.[426]

The AER is satisfied that Econtech's methodology for forecasting labour costs growth is robust given the application of both an economic-wide model (MM2) and a purpose-built LCM.[427] Econtech provided, in its report, additional information pertaining to its LCM and MM2 methodology and also advised further information and assumptions are publicly available.[428]

The AER sought a list of exogenous variables, and assumptions, employed by Econtech to produce its labour forecasts.[429] Further, the AER considers these forecasts to be adequately substantiated by Econtech's analysis across states and industries, and is consistent with national data and reflective of Econtech's national outlook based on the current economic climate.[430] The AER is satisfied that Econtech's modelling is transparent and appropriately reflects current economic conditions to produce reliable forecasts.

The AER notes Econtech's response to CEG's concerns regarding Econtech updating its labour forecasts.[431] Econtech stated the procedure used in updating the forecasts does not alter its methodology. Further, the structure of both the MM2 and LCM will remain the same as those applied in its September 2008 labour cost forecasts. Econtech also advised judgemental adjustments are applied in a systematic fashion designed to capture key economic information not contained in historical data. The AER is satisfied that Econtech has updated its forecasts, consistent with the process accepted in the draft decision, to produce robust labour growth forecasts to apply for the next regulatory control period.

The AER agrees with CEG's view that productivity adjustment can be an important factor in forecasting actual business costs.[432] Further, the AER notes that Econtech's forecasts are adjusted for productivity growth. Unlike the Macromonitor forecasts, Econtech's forecasts of wages growth do not remove productivity growth. Rather Econtech's forecasts of wage growth represent the general increases in wages (above CPI) as well as specific compensation to labour for increases in productivity. The AER notes Econtech's labour productivity assumptions are incorporated in its MM2 model through its labour productivity index. Further, MM2 incorporates assumptions regarding the growth in labour efficiency for each industry, enabling separate labour

425 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, op. cit. p. 39.
426 Econtech, *Updated labour cost growth forecasts*, op. cit. p. 21.
427 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*.
428 Econtech, *Updated labour cost growth forecasts*, op. cit.
429 Econtech, *Updated labour cost growth forecasts*, 25 March 2009, p. 25.
430 The AER and CEG have previously applied Econtech's national forecasts in the SP AusNet and VENCorp revenue resets. See AER, *Transend* d*raft decision*, p. 250.
431 Econtech, *Updated labour cost growth forecasts*, op. cit. pp. 20–26.
432 CEG, *Escalators affecting expenditure forecasts*, op. cit. p. 33.

productivity assumptions for each 1–digit ANZSIC industry.[433] The AER is therefore satisfied with the approach and methodology applied by Econtech to incorporate productivity in its wage growth forecasts.[434]

The AER also notes CEG's acknowledgment of Econtech as a reputable forecaster and that Econtech's forecasts have the advantages of being more recently developed, as they were based on more recent data. The AER further acknowledges CEG's comments that it is for these reasons that CEG accepted the use of the Econtech EGW wages and general labour forecasts applied by the AER in its draft determination as reasonable and has recommended the businesses adopt the Econtech forecasts in their revised regulatory proposals.[435]

Updated labour cost escalators

In the draft decision, the AER applied Econtech's general wage growth forecasts for all industries across Australia to escalate direct labour costs incurred by Transend.[436] However, the AER notes the application of Econtech's EGW labour growth forecasts, which are based on state/territory specific data, and Econtech's general labour growth forecasts, which are based on national data, are inconsistent. The AER is of the view that Tasmanian specific general labour escalators should be applied to Transend's general wages, as it reflects the economic circumstances and performance of Tasmania and is likely to be a better predictor of future trends in wages growth in Tasmania. Therefore, for this final decision the AER will apply Econtech's all–industries wage growth forecast for Tasmania as Transend's general labour escalator.

For this final decision, the AER has adopted actual wage data increases for 2007–08 provided for under Transend's EBA. Further, the AER has applied Transend's 2008–09 EBA rates to its EGW labour escalation. For the next regulatory control period the AER has adopted Econtech's updated the EGW labour cost escalators.

CEG has stated that the AER has indicated it would use future EBA labour costs where these are available.[437] To clarify, the AER is using the EBA rates, in the current regulatory control period to escalate labour costs from the base period (2006–07) to the end of the current regulatory control period. However, for the next regulatory control period the AER will adopt Econtech's updated EGW labour cost growth forecasts. The AER does not consider it appropriate to use Transend's EBA rates for the next regulatory control period as this would move Transend from an incentive based framework to a cost of service recovery framework. This means Transend still has an incentive to negotiate with its employees to obtain productivity savings under its EBA.

The AER considers that CEG's recommendations regarding the appropriate timing of the escalators the AER applied in the draft decision are generally reasonable. The AER has implemented CEG's recommendations to EGW and general labour by making refinements to its cost escalations model to ensure:

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433 Econtech, *Updated labour cost growth forecasts*, op. cit p. 24.

434 Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*,op. cit. pp. 41–42.

435 CEG, *Escalators affecting expenditure forecasts*, op. cit. p. 13.

436 AER, *Transend draft decision*, op. cit. p. 255.

437 CEG, *Escalators affecting expenditure forecasts*, op. cit. p. 8.

- inflation was correctly accounted for by only using real wage rates for both EBA rates and EGW rates
- the EBA rates are appropriately timed with EGW rates. As recommended by CEG the AER has addressed this by creating a quarterly index of real wage rates.

The AER notes that CEG converted Econtech's annualised EGW wage rates into quarterly rates using compounding formulae, however, this appears to cause a distortion of the annual wage rate. Econtech has recommended the AER adopt its approach of using a quarterly disaggregation formula which results in the same annual wage rate.[438] The AER has adopted Econtech's methodology for creating a quarterly EGW wage rate as it does not distort the annual wage rate.

The AER considered CEG's application of a compounding formulae when converting the yearly EBA wage rates to quarterly terms to be inappropriate as the increase in wage rates in reality are experienced from a single day. Therefore, CEG's approach can move escalations inappropriately between periods using the index approach as it smears the wage rate change over a year instead of being a single yearly adjustment. The AER has applied the whole EBA rate increase in the first quarter of the calendar year that corresponds to Transend's EBA wage rate increase date. This approach maintains CEG's application of the EBA rates in quarterly terms but applies the whole wage increase in the first quarter instead of over the year.

The AER has identified an error in CEG's model which mistimes the application of Econtech's EGW wage rates by applying a financial year's data to a calendar year—this effectively means that CEG has been using Econtech's labour rates six months before the period where they should be applied. The AER has corrected this error as part of the adjustments made for the appropriate timing of escalators in its model.

The AER notes that Transend, based on advice received from CEG, accepted the use of Econtech's forecasts in the draft decision as reasonable, subject to the AER rectifying the specified timing issues.[439] The AER further notes Transend's concerns with Econtech updating its forecasts after its revised revenue proposal had been submitted. To ensure a robust and transparent process on updating of labour wage growth forecasts, the AER engaged in a briefing with Transend, where Econtech provided an overview of its economic models used to derive the labour wage growth forecasts and the economic assumptions underlying its updated forecasts. The AER also outlined refinements to its cost escalations model from the draft decision.

The AER also notes submissions relating to labour cost escalators discussed changing economic conditions and the labour cost escalators applied in the draft decision are now out of date. Econtech was engaged by the AER to provide updated labour cost escalators based on most recent available data.[440] The AER considers the updated forecasts take account of the current economic slowdown.

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438 Econtech, *Updated labour cost growth forecasts*, op. cit. pp. 23–24.

439 CEG, *Escalators affecting expenditure forecasts*, op. cit. pp. 7–12.

440 New forecasts incorporate data published by the Australian Bureau of Statistics, including Average Weekly Earnings (released 26 February 2009) and National Accounts (released 9 March 2009).

EBA employee increments and performance payments

Transend has sought employee increments above the base EBA wages rate in its revised revenue proposal. The AER understands that these increments are:

- salary progression to individual staff (i.e. permanent increases in wage) based on the objective to appropriately position staff within a given salary band in a fair and equitable manner recognising skills, experience (competence) and performance.[441]
- part of a remuneration process for retaining staff
- only applied to select staff who outperform their key performance indicators.

The AER notes that Transend's EBA suggests the annual salary progression policy is used to allow 'performance payments' which are increases in pay based on productivity improvements by individual staff. The AER has requested additional information on these issues but to date, Transend have been unable to demonstrate that these payments are made across the entire organisation.

The AER is not satisfied that Transend has demonstrated how individual performance bonuses paid to employees would result in higher productivity levels for the entire organisation, and therefore the need to allow the cost impact to Transend's opex. The AER also notes that Transend's EBA states that salary progression is not automatic under Transend's performance planning process.

The AER notes that performance bonuses generally reflect individual employee productivity improvements and as such are selective, rather than broad based payments.[442] Any bonus paid by Transend, provided it is less than the cost of employing new staff to increase output by the equivalent productivity increase, should result in cost savings for Transend.[443] Therefore, the AER is not satisfied that Transend has appropriately quantified the increase to its labour costs through its application of performance targets and individual productivity relative to increased productivity of Transend in its entirety.

The AER also notes that the only other NSP to apply for a similar productivity related rate above the EBA allowance is ActewAGL in its 2009–14 revenue proposal. ActewAGL sought to include performance amounts with the (base) EBA rate and this was rejected by the AER.

Conclusions

For this final decision, the AER has adopted Econtech's updated Tasmania EGW wage growth forecasts for the next regulatory control period. The AER has remodelled the forecasts to address CEG's timing issues and applied these updated forecasts for the EGW sector in Tasmania for the next regulatory control period. Actual wage data, however, was available for 2007–08 to 2008–09 and therefore, the AER has applied actual wage increases provided for under Transend's workplace EBA for that year, which have also been remodelled to address the timing issues.

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441 Transend, *Transend Networks Pty Ltd: Enterprise agreement 2006*, 17 February 2006.

442 The AER notes Econtech's labour cost forecasts are adjusted for productivity growth which is applicable to all NSPs across their entire workforce. For further discussion, see: Econtech, *Updated labour cost growth forecasts*, pp. 20–26.

443 That is, while labour costs may increase, total costs per unit of output will decrease.

The AER's conclusion on the EGW labour cost growth forecasts to apply to Transend for the next regulatory control period is shown in table A.7.

Table A7: AER's conclusion on Tasmanian real EGW labour growth rates (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Econtech/AER	0.3	1.1	2.7	2.7	1.3	0.6	-0.3

For this final decision, the AER has also adopted Econtech's updated Tasmania general labour cost escalators for 2007–08 to 2013–14. The general labour cost growth forecasts the AER will apply to Transend's capex and opex for the next regulatory control period are set out in table A.8.

Table A8: AER's conclusion on Transend's real general labour escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Econtech/AER	-2.2	-1.9	0.0	0.5	-0.7	-1.0	-1.5

As a result of the AER's analysis of the revised revenue proposal, the AER is satisfied that the application of the updated EGW and general labour cost escalators for Tasmania (as set out in tables A.7 and A.8), to Transend's capex and opex results in expenditure reasonably reflects the capex and opex criteria, including the capex and opex objectives. In coming to this view, the AER has had regard to the capex and opex factors.

A.6 Construction costs

A.6.1 AER draft decision

The AER, for the same reasons as set out for EGW wages and general labour forecasts (section A.5), also rejected CEG's approach to averaging construction forecasts from Econtech and Macromonitor. In the draft decision, the AER applied construction cost forecasts sourced from the Construction Forecasting Council (CFC) website[444], which it deflated by CPI.[445] The draft decision for construction cost forecasts are set out in table A9.

Table A9: AER's draft conclusions for Transend construction cost forecasts (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
Construction costs	–0.3	–1.9	0.4	1.2	1.1	1.0	1.0	0.9

Source: AER, *Transend draft decision*, p. 126.

444 Construction Forecasting Council website http://www.cfc.acif.com.au/.

445 The CPI figures used to deflate the construction cost forecasts were sourced from: Econtech, *Australian national state and industry outlook*, 22 July 2006.

A.6.2 Revised regulatory proposals

Transend accepted the construction cost escalator methodology applied by the AER in the draft decision, subject to the addressing of the issues raised by CEG and addressed in section A.6.3 of this appendix.[446]

A.6.3 AER considerations

The AER, as per the discussion on EGW wages and general labour forecasts, applies the same approach to construction costs. It maintains the position it took in the draft determination to apply Econtech's construction cost forecast escalators. It does not consider it appropriate to rely on Macromonitor forecasts because there is no description of the methodology used to forecast growth for the AER to make an assessment.

The AER also considers that CEG's recommendation to use an index to determine the construction cost escalator is reasonable. Specifically, when used in conjunction with Econtech's yearly to quarterly conversion adjustment, it enables the appropriate base period to be factored into the calculation of this escalator. This issue is discussed in more detail in the EGW and general labour section (section A.5).

AER conclusions

The AER notes Transend[447] accepts the application of its construction cost forecasts, subject to the AER reconciling the timing issues raised by CEG.[448] The AER has adjusted its modelling to reflect timing issues raised by CEG.

The AER has applied updated CFC construction cost forecasts to Transend's capex proposals, as published on the CFC website on 27 March 2009.[449] The AER has deflated these construction costs with updated ANSIO inflation forecasts to provide real forecasts.[450]

The AER's conclusions on forecast construction cost escalators are set out in table A10.[451]

Table A10: AER's conclusion on Transend's real construction cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Construction Costs	1.4	-1.3	-1.6	1.0	0.6	-0.4	-2.2

446 This decision is not applicable to Country Energy as it did not identify any construction capex in its regulatory proposal.

447 This decision is not applicable to Country Energy as it did not identify any construction capex in its regulatory proposal.

448 CEG, *Escalators affecting expenditure forecasts*, pp. 7–12.

449 AER, *Trasend draft decision*, op. cit. Appendix N, p.560.

450 Econtech, *Australian national state and industry outlook*, 23 January 2009.

451 This decision is not applicable to Country Energy as it did not identify any construction capex in its regulatory proposal.

A.7 Producer margin

A.7.1 Draft decision

The AER rejected the producer's margin escalators proposed by Transend as it did not meet the underlying objective for inclusion in forecast costs under clause 6A.6.7(c) of the NER. Based on the information presented by Transend, the AER was not satisfied, that the associated expenditure reasonably reflected a realistic expectation of cost inputs over the next regulatory control period.[452]

The AER considered the addition of a producer's margin escalator would represent a:[453]

- movement beyond the AER's obligation to provide a reasonable opportunity to recover efficient costs
- level of compensation for costs that is inconsistent with the general incentive framework.

The AER therefore allocated the portion of costs assigned to this escalator to the 'other' escalation category, which was escalated by CPI.[454]

A.7.2 Revised proposal

Transend accepted the AER's draft decision on producer's margin. It submitted revised cost escalators which removed real cost escalation from this proposed component.

A.7.3 AER considerations

The AER accepts Transend's revised proposal to remove real cost escalation from the proposed producer's margin component of its forecast equipment purchase costs.

For the reasons discussed in its draft decision, the AER is not satisfied that the inclusion of real cost escalation for proposed producer's margin components of equipment costs reasonably reflects the capex criteria, including the capex objectives. The AER does not consider that its inclusion is likely to produce forecast costs that reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives. In coming to this view, the AER has had regard to the capex factors.

A.8 Indirect (producer's) labour

A.8.1 Draft decision

The AER did not accept the producer wage cost escalator applied by Transend. The AER considered that it did not meet the underlying objective for inclusion in forecast costs under clause 6A.6.7(c) of the NER. Based on the information presented by

452 AER, *Transend draft decision*, op. cit. p. 386.
453 ibid.
454 ibid.

Transend, the AER was not satisfied that the expenditure associated with a real escalation of indirect labour costs is required to meet the capex and opex objectives.[455]

The AER considered that the introduction of a labour component in equipment costs was inappropriate as it:[456]

- represented 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
- was sufficient to monitor whether the cost of finished goods, as opposed to the component parts, needed to be escalated above or below CPI
- was not supported by robust data.

The AER further noted that some amount of producer's labour costs would have been embedded in the NSPs' base cost estimates of equipment.[457]

A.8.2 Revised proposal

Transend accepted the AER's draft decision on indirect producer's labour. It submitted revised cost escalators which removed real cost escalation from this proposed component.

A.8.3 AER considerations

For the reasons discussed in the draft decision, the AER is not satisfied that the inclusion of real cost escalation for producer's labour components of equipment costs reasonably refects the capex objectives. The AER does not consider that its inclusion is likely to produce forecast costs that reasonably reflect a realistic expectation of the cost inputs required to achieve the capex objectives. In coming to this view, the AER has had regard to the capex factors.

Consistent with the draft decision, the AER's has therefore applied a zero weighting to the indirect producer's labour components of Transend's base equipment cost escalators. That is, any weighting attributed to producers labour has been reallocated to an alternative 'other' cost factor category which will attract CPI escalation only.

A.9 Exchange rates

A.9.1 Draft decision

The AER considered that an exchange rate forecast by Econtech at the time of the final decision would represent a realistic expectation of forecast exchange rates over the next regulatory control period. For the purposes of the draft decision, the AER used the exchange rates set out in table A11.

455 AER, *Transend draft decision*, op. cit. p. 366.
456 ibid.
457 ibid.

Table A11: AUD/USD exchange rate forecasts

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Revenue proposals	0.85	0.88	0.88	0.87	0.85	0.84	0.83
AER draft decision	0.85	0.96	0.88	0.84	0.82	0.80	0.79

Source: AER, *Draft decision*, pp. 382, 383

A.9.2 Revised regulatory proposals

In Transend's revised revenue proposal it used the cost escalators calculated by CEG. CEG, in its cost escalation model, assumed future exchange rates were equal to those forecast by Econtech in its October 2008 ANSIO report.[458] This represented the most recent forecasts available to CEG at the time it submitted the cost escalators to Transend.

A.9.3 AER considerations

Consistent with the draft decision, and Transend's revised regulatory proposals, the AER has used the most recent available exchange rate forecasts from Econtech to calculate the cost escalators. The exchange rates used are set out in table A12.

Table A12 AUD/USD exchange rate forecasts

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Revised revenue proposals	0.85	0.96	0.66	0.65	0.64	0.64	0.64
AER final decision	0.85	0.96	0.67	0.65	0.63	0.62	0.62

Sources: Econtech, *Australian national state and industry outlook*, 30 October 2008, p. 110; and Econtech, *Australian national state and industry outlook*, 23 January 2009, p. 110.

A.10 Other issues

A.10.1 Inflation

Revised regulatory proposals

CEG stated that it largely agreed with the AER's application of inflation in its calculation of cost escalators in the draft decision. However, it proposed a more accurate approach was possible with respect to the handling of inflation prior to June 2009.[459]

AER considerations

The AER undertook a review of its calculation of inflation. The AER considers that the approach to handling inflation adopted by CEG is more accurate than the

458 Econtech, *KPMG Econtech's Australian national state and industry outlook*, October 2008.
459 CEG, *Escalators affecting expenditure forecasts*, op. cit. p. 17.

approach used by the AER in the draft decision, although the difference is relatively minor.

However, the AER also determined that the methodology could be further improved by using the most recent historical monthly inflation figures rather than using yearly inflation figures. The AER therefore amended its methodology to incorporate this change, which also removed the need for it to amend the calculation of historical inflation as proposed by CEG.[460]

A.10.2 Historic steel data

Revised regulatory proposals

CEG proposed using historical carbon steel prices for Europe and the US to enable the use of one more year of historical data and the appropriate application of its proposed methodology.

AER considerations

As noted, the AER has accepted that the methodology it applied to materials escalators could be improved (section 9.4). The AER also accepts that CEG's proposed use of one year's worth of carbon steel historical data is appropriate, as this will facilitate the calculating of historical steel prices while maintaining the methodology that the AER has adopted.[461] The AER notes, however, that in future determinations there will be sufficient historic data available to permit the use of hot rolled coiled (HRC) steel price data to fully determine HRC steel escalations.

A.10.3 Historic oil data

Revised regulatory proposals

In it original and revised reports, CEG used an all countries trade weighted spot price for historical oil prices in its modelling.

AER considerations

The AER considers that the most appropriate historical oil series to be used with the NYMEX oil futures prices is the West Texas Intermediate data series.[462] The AER considers that for data consistency, the West Texas Intermediate historical series should be used as the NYMEX oil futures prices are for West Texas Intermediate oil. The AER has amended its approach to correct for this error.

A.11 Conclusion

The AER's conclusions on cost escalators for Transend are set out below.

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460 CEG, *Escalators affecting expenditure forecasts*, op. cit. p. 17.

461 This methodology involves calculating the HRC steel prices using European and US steel price indexes.

462 US Energy Information Administration, viewed 18 February 2009, http://www.eia.doe.gov/.

Table A13 AER's conclusion on Transend's real escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	-8.5	-17.3	-14.1	9.1	10.5	10.9	9.3
Copper	-4.3	-27.9	-10.8	2.1	2.5	2.3	2.0
Steel	12.1	16.3	-15.3	7.2	5.2	1.0	0.8
Crude Oil	31.2	-18.3	-5.2	10.2	5.7	2.2	1.3
EGW wages	0.3	1.1	2.7	2.7	1.3	0.6	-0.3
General wages	-2.2	-1.9	0.0	0.5	-0.7	-1.0	-1.5
Construction costs	1.4	-1.3	-1.6	1.0	0.6	-0.4	-2.2

Appendix B: Contingent projects and their triggers

This appendix sets out the drivers of approved contingent projects, their scope and specific trigger events. Under clause 6A.8.2 of the NER, Transend must demonstrate to the AER's satisfaction that the relevant trigger event relating to a contingent project has occurred before an assessment of any adjustments to Transend's maximum allowed revenue (MAR). Where a trigger event has occurred, the scope of the contingent project must not include any projects (or associated project scope) that were contained in Transend's approved ex ante capex allowance.

The AER released its *Process guideline for contingent project applications under the National Electricity Rules – September 2007* (contingent project guidelines) to assist transmission network service providers (TNSPs) to prepare contingent project applications that meet the NER processes and requirements. Under this guideline, the timing of the assessment process of a contingent project application includes pre-lodgement consultations. The AER envisages that at the end of the pre-lodgement process the TNSP should have a good understanding of the information required by the AER and also be in a position to submit an application that complies with the NER.

Where Transend makes a contingent project application, it is expected to comply with the contingent project guideline 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. The AER expects Transend to provide best available supporting information with its contingent project application, which would generally include:

- the final regulatory test assessment
- tender submissions
- contracts
- other investment appraisals.

Sheffield–George Town new transmission line

The driver for this project is to provide adequate network capacity to allow for the connection of new generation in the north-western and/or western regions.

The scope of the project involves the establishment of a third 220 kV transmission circuit between Sheffield and George Town substations, including the construction of switch bays at Sheffield and George Town substations to cater for a new transmission line.

The indicative cost of this project is $70 million (June 2009).

The trigger for this project will occur if application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in northern-western and/or western Tasmania when there is committed and/or advanced generation projects in the north-western and/or western regions in excess of 50 MW.

Burnie–Smithton new transmission line

The driver for this project is to allow for adequate network capacity in north-western Tasmania if new generation is connected to the network.

The scope of the project involves the construction of a new double circuit transmission line between Burnie and Smithton substations and an augmentation of the existing Burnie–Smithton transmission line. The indicative cost of this project is $88 million (June 2009).

The trigger for this project will occur if application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in northern-western and/or western Tasmania when there is committed and/or advanced generation projects in the north-western region in excess of 50 MW.

Sheffield–Farrell new transmission line

The driver for this project is to provide adequate network capacity to allow for the connection of new generation in the north western and western regions of Tasmania.

The scope of the project involves the construction of a new transmission line between Sheffield and Farrell substations. The project may also involve the construction of a new switching station in the Staverton area near Cethana power station that would consolidate the three incoming circuits from the Farrell substation and the four incoming circuits form Cethana, Wilmot, Lemonthyme and Fisher power stations into the six circuits that would connect to Sheffield substation.

The indicative cost of this project is $79 million (June 2009).

The trigger for this project will occur if application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in western Tasmania when there is committed and/or advanced generation projects in the west coast area in excess of 50 MW.

Sheffield–Burnie new transmission line

The driver for this project is to provide adequate network capacity to allow the connection of new generation in the north-western and western regions and/or to cater for load growth in the region.

The scope of the project involves the establishment of a new double-circuit 220 kV transmission line between Sheffield and Burnie substations, including the construction of switch bays and Sheffield and Burnie substations to cater for new circuits. The existing 220 kV Sheffield–Burnie transmission line will be decommissioned.

The indicative cost of this project is $52 million (June 2009).

The trigger for this project will occur if demand in Tasmania's north-western region exceeding 360 MW and application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in northern-western and/or western Tasmania when there is committed and/or advanced generation projects in the north-western region in excess of 50 MW.

St Helens new 110/22 kV connection site

The drivers for this project are to cater for the forecast demand growth in the St Helens area and to comply with the minimum network performance levels under the Tasmanian *Electricity Supply Industry (Network Performance Requirements) Regulations 2007*.

The scope of the project involves the construction of a 110 kV transmission line from Derby substation to a new connection site at St Helens. The establishment of a new connection site at St Helens would be the first stage of the long-term strategy to form a 110 kV transmission connection between Derby and St Marys substations.

The indicative cost of this project is $47 million (June 2009).

The trigger for this project will occur if the demand forecast in the east coast region exceeds 55 MW and application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in the St Helen's region.

Palmerston–Sheffield 220 kV transmission line augmentation

The drivers for this project are to provide adequate network capacity to allow for the connection of new generation in the north-western and western regions.

The scope of the project involves the augmentation of the Palmerston–Sheffield 220 kV transmission line and the associated switch bays at Palmerston and Sheffield substations. The technical parameters for the augmented transmission line have not yet been determined in detail; however the indicative cost is based upon re-tensioning the Palmerston–Sheffield 220 kV line to a design temperature of 80 degrees Celsius.

The indicative cost of this project is $22 million (June 2009).

The trigger for this project will occur if application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in northern-western and/or western Tasmania when there is committed and/or advanced generation projects in the north-western and/or western regions in excess of 50 MW.

Waddamana–Lindisfarne 220 kV transmission line second circuit

The drivers for this project are to cater for forecast demand growth in southern Tasmania and to improve the security of supply to the southern region.

The scope of the project involves the installation of a second 220 kV transmission circuit from Waddamana substation to Lindisfarne substation and a second 220/110 kV auto-transformer at Lindisfarne substation. The work would include the installation of:

- 99 kilometres of 220 kV line to be strung on the existing double circuit towers

- one new switchyard bay at Waddamana substation and two at Lindisfarne substation
- circuit breakers, associated protection and control and required civil works.

The indicative cost of this project is $22 million (June 2009).

The trigger for this project will occur if application of the regulatory test demonstrates:

(i) this option maximises the net economic benefit for the provision of prescribed services when demand in Tasmania's southern area is forecast to exceed 880 MW or Gordon power station is not able to provide reactive support when the southern area load exceeds 775 MW; or

(ii) the reliability limb is satisfied when a Transend planning study demonstrates a need under the Tasmanian *Electricity Supply Industry (Network Performance Requirements) Regulations 2007* for the construction of the second circuit in the next regulatory control period and this option minimises the costs of meeting those requirements.

Trevallyn Substation new 220/110 kV injection point

The drivers for this project are to cater for forecast demand growth in the northern area and to comply with the minimum network performance levels under the Tasmanian *Electricity Supply Industry (Network Performance Requirements) Regulations 2007.*

The scope of the project comprises the establishment of a transmission line from Hadspen substation to Trevallyn substation, and an additional 220/110 kV injection point at Trevallyn substation. The scope includes:

- 1.3 km of single circuit 220 kV transmission line
- 1 x 220 kV switchgear bay
- 1 x 200 MVA 220/110 kV auto-transformer
- 1 x 110 kV switchgear bay
- associated protection and control for 220 kV circuit
- associated protection and control for 220/110 kV auto-transformer.

The indicative cost of this project is $21 million (June 2009).

The trigger for this project will occur if demand in Tasmania's northern area exceeds 320 MW and is forecast to exceed 355 MW within 3 years and application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in the Trevallyn region.

Queenstown transmission security upgrade

The driver for this project is to comply with the network performance requirements.

The scope of the security upgrade project comprises of the establishment of a 220/110 kV supply from a transmission circuit adjacent to Queenstown substation.

The indicative cost of this project is $21 million (June 2009).

The trigger for this project will occur if Transend is unable to negotiate non-network solutions that enable it to meet the minimum network performance requirements for the Queenstown and Newton load and application of the regulatory test demonstrates this option maximises the net economic benefit for the provision of prescribed services or this option minimises the costs of meeting a reliability driven need in the Queenstown region.

Appendix C: Risk–free rate averaging period

The AER concurrently assessed the revised revenue proposals of two TNSPs (TransGrid and Transend) and the revised regulatory proposals of four DNSPs (ActewAGL, Country Energy, EnergyAustralia and Integral Energy). Within this appendix these six regulated businesses are collectively referred to as the network service providers (NSPs). For convenience, within this appendix the term regulatory proposal should be taken to include the term revenue proposal, where the AER is referring to the NSPs. Within this appendix the AER has also used the term draft decision to refer to any and all of the relevant draft decisions affecting the NSPs. Where it has been necessary to refer to a draft decision for just one of the NSPs, within this appendix the AER has identified the specific business when referencing the draft decision, rather than applying the generic term draft decision, as defined in the shortened forms.

The AER's consideration of the substantive arguments put forward by the NSPs in their revised regulatory proposals, submissions and consultant reports are set out below.[463]

Following the withholding of agreement to the averaging periods lodged with the regulatory proposals, the AER in consultation with the NSPs established the risk–free rate averaging periods (agreed averaging periods) prior to the draft decision. The AER views its agreed averaging periods decision as part of its draft and final decisions and has reviewed the further material provided by the NSPs as part of this final decision.

The AER notes that the NSPs' consultants appear to have based their advice on a legal interpretation of the NER.[464] CEG stated that it has worked on the basis that when determining the averaging period it is a relevant consideration under the NER that the period should give rise to an estimate of the rate of return that is consistent with:

> …the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk.[465]

Although not necessarily agreeing with the NSPs and their consultants' interpretation of the relevant clauses, the AER has considered the key arguments put forward in the revised regulatory proposals and the additional material.

The NSPs' key argument in their revised regulatory proposals is one that suggests an obligation on the AER to move away from the agreed averaging period if that period is set in abnormal times. The alleged abnormality affecting the agreed averaging

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463 The arguments put forward and consultant reports referred to by each NSP are set out in the cost of capital chapter.

464 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 4; Prof. Bruce Grundy, *The WACC and the averaging period*, 16 February 2009, p. 5 and Officer R.R., *Expert report prepared in respect of certain matters arising from the AER's NSW draft distribution determination*, 16 February, 2009, p. 4.

465 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 4.

period was not manifest at the time of the AER's July 2008 decision to withhold agreement. The issue therefore is whether the averaging periods in the revised regulatory proposals are reasonable compared with the agreed averaging periods.

C.1 Theoretical basis for the averaging period

In setting the averaging period close to the start of the next regulatory control period, the AER is seeking to set an unbiased risk–free rate to be applied in the weighted average cost of capital (WACC) formula, to derive an unbiased estimate of the regulated rate of return over the next regulatory control period.

In theory, the risk–free rate on the day that the regulatory determination comes into effect provides the best expectation of the future rate. This reflects the notion that the on–the–day rate fully reveals all the information available in the market. However, using the on–the–day rate exposes the firm to market volatility on a given day. Therefore, an averaging period is used to address the trade–off between 'volatility driven error' (due to exposure to an aberrant day) and 'old information driven error' (invalid past information) in interest rates. The averaging period also allows a firm to hedge its cost of debt over an extended period and counteracts the potential volatility of a single day's observation.

Professor Officer in his review of the CEG report accepted this theoretical position. He noted that:[466]

> In theory, the task of estimating the $Rf_{,t}$ is made easy because it is assumed constant and 'known for certain' at the time the rate is set. In practice there is no observed $Rf_{,t}$, instead the yield on a 10 year Commonwealth Bond/Security (CGS) is used as surrogate. This yield should theoretically be taken from the CGS as close as practical to the start date of the regulated period.

The AER considers the use of an averaging period as close to the start of the next regulatory control period as practically possible is consistent with the forward looking nature of the capital asset pricing model (CAPM) and is correct in finance theory.

C.2 The market risk premium

CEG stated that, in the NER the market risk premium (MRP) is fixed at 6 per cent but the risk–free rate is set within an averaging period. Therefore, it noted that using the most up to date estimate of the Commonwealth Government Securities (CGS) yield will only result in the most accurate estimate of the cost of equity if investors' cost of equity moves one for one with movements in CGS.[467] CEG also claimed that sampling yields from bond markets at these times (February 2009) and the foreseeable future will result in bond yields being sampled during abnormal market conditions and unreliable estimates of the cost of equity.[468] Further, it noted that in the current

466 Officer R.R., p. 6.
467 CEG, *Rate of return and the averaging period*, op. cit. pp. 7–12.
468 ibid., p. 29.

global financial crisis returns from holding government bonds have had a negative relationship with returns from holding equity.[469]

Strategic Finance Group (SFG) stated that the CAPM does not specify how to estimate the risk–free rate and asserted that it should be estimated in a way that gives the best estimate of the required return on equity when combined with other input parameters.[470] Professor Grundy's underlying argument was that the MRP has increased and therefore an adjustment to the risk–free rate is appropriate. In particular, he stated that CAPM theory does not imply that the best estimate of the return on equity is either obtained by:

- adding 6 per cent to the risk–free rate at the start of the regulatory control period or
- adding 6 per cent to the moving average of the risk–free rate as close as possible to the start of the regulatory control period.[471]

Professor Officer also suggested that the MRP at current times is higher than the MRP derived from long–term averages. Therefore, he noted that setting the risk–free rate which is at a 'low level' at current times relative to 'normal' whilst using a MRP from a more 'normal' time period does not result in an unbiased estimate of the cost of capital.

SFG stated that it is not necessarily the case that a fall in equity values must be caused by an increase in the required return on equity because a fall in future profits could also be the reason. However, based on its analysis, SFG noted that implausibly large reductions in expected corporate profits for implausibly long periods would be required to reconcile equity movements with the required return on equity estimated using the approach set out in the draft decision. Therefore, it concluded that the most plausible conclusion was that the required return on equity had risen over this period.[472]

The AER recognises that the CAPM does not state that the CGS is the best proxy for the risk–free rate. However, the CGS is arguably the most commonly used proxy when applying the CAPM in Australia—suggesting widespread acceptance in practice. In addition, the use of the CGS is specified in the NER.

The AER also recognises that the CAPM does not predict that the cost of equity capital necessarily moves one for one with the risk–free rate.

The AER notes that the arguments put forward by the NSPs regarding an insufficient return on equity is based on the view that the MRP of 6 per cent in the NER (based on a historical average) is out of line with the current variations in the MRP. In essence, the NSPs are arguing for a variable MRP to be applied in the CAPM, but given that it is prescribed in the NER they consider it reasonable to account for variations in the MRP via adjustments to the risk–free rate.

469 CEG, *Rate of return and the averaging period*, op. cit. p. 11.
470 SFG Consulting, *Review of TransGrid approach to WACC averaging period*, 14 February 2009, pp. 17–18.
471 Grundy, 16 February 2009, pp. 3–4.
472 SFG Consulting, p. 23.

The AER considers that any implied (or actual) MRP changes cannot be addressed in this final decision. The AER notes that even if the MRP has increased somewhat over the last 12 months, it is unclear as to the margin of increase or whether there is an accepted theoretically sound methodology to take account of time varying MRP. The AER considers that a reasonable conclusion that can be drawn from current equity prices (if at all) would only be that the investors' perception of risk appears to have changed recently.

The AER notes that adjusting the risk–free rate averaging period as a mechanism to achieve the outcome equivalent to adopting a higher MRP (due to implied or actual variations to the historical MRP) is an attempt to circumvent WACC parameters prescribed (subject to five yearly reviews) in the NER. It would undermine the intended certainty provided under the regulatory regime which results from these values being prescribed.

Additionally, the AER notes that the NSPs' regulatory asset bases (RAB) are fixed (subject to depreciation and other NER prescribed adjustments) and receive regulated returns that comprise of both returns on equity and debt. Further, the NSPs' regulated cash flows provide significant certainty over earnings, dividends and debt servicing. This fixed RAB coupled with certainty in returns provide significantly more stable shareholder returns for the NSPs than for unregulated businesses whose future cash flows are highly uncertain. The NSPs are therefore insulated to a large degree from the factors that affect equity values during the current economic circumstances. In this context, arguments suggesting that returns provided to NSPs in a significantly more stable regulated environment should be comparable with higher expected returns for unregulated businesses due to the global financial crisis are unreasonable.

C.3 Historically low nominal risk–free rate

CEG stated that the weight of the regulatory precedent from overseas and Australia supports a view that if the most recent averaging period overlaps with abnormal levels of the risk–free rate or periods of economic crisis then such a period should not be adopted.[473]

The AER notes that this is a continuation of the argument for a variable MRP given the alleged abnormally low CGS yields. However, given the dramatic changes in circumstances within the economic environment the AER has considered whether in fact the agreed averaging periods will result in an unreliable estimate of the risk–free rate such that it no longer reflects a reasonable forward looking estimate.

The AER's discretion in setting the nominal rate of return under clause 6.5.2 of the transitional chapter 6 rules and clause 6A.6.2 of the NER is limited to determining the reasonableness of the averaging period used to derive the nominal risk–free rate and the debt risk premium. The proxy for the risk–free rate—based on CGS yield—and the maturity period (10 years), including the requirement to average the observed rates are prescribed in the NER. The debt risk premium is defined in terms of a margin between the CGS yield and a benchmark corporate bond with a credit rating of BBB+. Given the level of prescription, the AER considers that the NER intended for

473 CEG, *Rate of return and the averaging period,* op. cit. p. 64.

the WACC to vary over time in line with the interest rate cycle as opposed to being fixed.

The fact that CGS bond yields are at (or close to historical lows) does not of itself mean they cannot be used. Interest rates move all the time and reflect the market's assessment of the price of money at the time. Expectations about the prospect for prices and growth will influence this assessment. Brailsford, Handley and Maheswaran show that the nominal 10 year CGS yield averaged 5.7 per cent over 1883 – 2005 and 8.2 per cent over 1958 – 2005. In comparison the CGS yield rate based on February 2009 is close to 4.3 per cent being 1.4 per cent below the long–term average.[474]

The AER considers that the material provided by the NSPs in support of their revised regulatory proposals does not reasonably justify that, an averaging period prior to 5 September 2008 or an averaging period of 12 months ending on 20 March 2009 is better than a period that is as close as practically possible to the start of the next regulatory control period. Moreover, the agreed averaging periods do not exclude the downward movement of the CGS yields commensurate with an easing in monetary policy and a softening in economic growth. The AER considers that the agreed averaging periods are not abnormal and setting the risk–free rate using this period is also consistent with the NEL objective of efficient investment. The AER therefore considers that the agreed averaging periods do not represent an abnormal period in relation to the observed CGS yields.

Given that all WACC parameters are prescribed in the NER except for the risk–free rate and debt risk premium, the AER considers that the WACC commensurate with interest rate expectations in the economy—resulting from the agreed averaging periods—is consistent with the NER and the NEL objective.

Professor Grundy referenced a paper by Krishnamurthy and Vissing-Jorgenson and stated that US federal government securities are biased downwards due to unique collateral and liquidity features relative to other assets. In the US market this was estimated at 1 per cent pre–September 2008. EnergyAustralia stated that previously, the ACCC had referenced other industry and accounting practices when making a decision and noted that the Institute of Actuaries of Australia (IAA) noted that the CGS yields were not necessarily a perfect proxy for the risk–free rate. EnergyAustralia stated that if the CGS yields were to be used—given the current market conditions and the liquidity premium paid for CGS—the IAA recommended an upward adjustment.[475]

The paper by Krishnamurthy and Vissing-Jorgensen (2008) considers the most appropriate indicator of the risk–free rate. Similarly, the IAA also appears to be considering the appropriate proxy for the risk–free rate. The AER notes that it has no discretion on using a proxy other than the CGS for the risk–free rate as it has been specified in the NER and therefore considers this reference irrelevant.

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474 Tim Brailsford, John C Handley, Krishnan Maheswaran, *Re-examination of the historical equity risk premium in Australia*, Accounting and Finance 48 (2008), p. 73–97.

475 EnergyAustralia, *Further submission on the AER's draft decision*, p. 9.

Professor Grundy noted that as the global financial crisis gathered, the gap between CGS and other zero beta debt securities has grown, as seen by the widening gap between NSW Treasury and CGS yields.[476] CEG also stated that the nominal CGS yields are depressed as evident by the high premium long–term state debt is attracting over the CGS yields and noted that this was due to the heightened demand for the liquidity of the CGS in a financial crisis.[477]

The AER understands CEG's argument as one suggesting that the CGS yield is an inappropriate proxy for the risk–free rate. The argument is based on the margin between CGS and state debt yields which is interpreted by CEG as evidence of the heightened demand for the liquidity of CGS.

The AER notes that Associate Professor Handley argues that it is unclear whether a premium should be paid for CGS or whether a discount should be applied to non–CGS assets due to their relative liquidity characteristics.[478] The AER therefore considers that it is unreasonable to conclude that the CGS yield is downwardly biased due to a heightened demand for the CGS liquidity.

The AER considers that the difference between the yields of state debt and the CGS does not diminish the suitability of the CGS as the best proxy for the risk–free rate. Moreover, the NER prescribes the use of the CGS as the risk–free rate. Additionally, the AER notes that the margin between state debt and CGS can also be attributed to a number of factors bearing on state government finances, including their debt servicing capacity.

C.4 Inconsistency between nominal and indexed bond yields

CEG stated that the AER should address the issue that an averaging period post September 2008 is likely to result in the adoption of CGS yields depressed in absolute terms as well as relative to the indexed CGS yields.[479]

The AER acknowledges that CGS yields have declined post September 2008 but notes that, as discussed above, this decline is not abnormal but consistent with changes in economic conditions.

CEG stated that since the global financial crisis the 'flight to safety' has resulted in such a high liquidity premium being paid for CGS that this now exceeds the 'peace of mind' premium being paid for indexed CGS. Therefore, CEG considered that if the AER's inflation estimates are applied in the current circumstances then it will make the estimate of the real risk–free rate less accurate rather than more accurate.[480]

The AER maintains its view that indexed CGS yields are not set in a well functioning market and therefore do not reflect informed market opinion or can be relied upon for deriving the future expectations of inflation (see section 5.5.3). This issue was

476 Grundy, pp. 10–11.
477 CEG, *Rate of return and the averaging period,* op.cit. pp. 36–39.
478 John C. Handley, *Comments on the CEG report: establishing a proxy for the risk–free rate, Report prepared for the AER*, 12 November 2008, p. 4.
479 CEG, *Rate of return and the averaging period*, op.cit. pp.40–46.
480 ibid., p. 42.

previously considered by the AER in the 2008 SP AusNet transmission determination and also referred to in the 2008 ElectraNet transmission determination. No evidence has been provided to the AER that these inefficiencies have now been addressed. Given the inefficiencies of the indexed CGS market, the AER considers that very little weight (if any) can be placed on outcomes derived by comparing relative movements between nominal and indexed CGS yields.

The AER considers that CEG's conclusions based on relative movements between nominal and indexed CGS yields are unreasonable because any such conclusion will be tainted with the inefficiencies in the indexed CGS market.

C.5 Cost of debt

CEG stated that the best averaging period to estimate the cost of debt is the period that results in the best estimate of the cost of debt obligations actually entered into by the NSPs (or alternatively, obligations entered into by an efficient benchmark firm). Therefore, it stated that the best estimate of the cost of debt should be analysed based on whether debt is refinanced/hedged during the agreed averaging period or outside the period. CEG's view is that cost of debt will never be determined by a single averaging period and therefore, efficiently incurred debt will reflect debt market conditions over an extended period of years.[481]

The AER considers that the expected cost of debt over the regulatory control period should equal an estimate of the cost of debt at the start of the regulatory control period (as this is what the market at that time is requiring to invest in debt securities over the regulatory control period). As a proxy for the expected cost of debt, the yield to maturity (YTM) on an efficient benchmark firm's debt (prescribed by the NER as BBB+) at the start of the regulatory control period is adopted, irrespective of when the NSP issued the debt or the YTM on the debt it issued. The debt financing strategies of the NSPs are not prescribed by the AER. Even if firms could not hedge over an averaging period this does not imply that an estimate based on an averaging period close to the start of the regulatory control period is not the best forward looking unbiased estimate of the cost of debt over the regulatory control period or that it will systematically under compensate the regulated firm. The AER does not agree with CEG's underlying assumption that the best estimate of the cost of debt under the NER is an estimate set in an averaging period that a regulated business (or efficient benchmark business) is able to hedge/refinance its debt.

On the basis that the best estimate should be used, Professor Grundy stated that although the return on debt is independent of the risk–free rate, an estimate of the cost of debt ending on 5 September 2008 is appropriate.[482]

As discussed before, the AER notes that interest rates have reduced since September 2008 consistent with current monetary policy and growth expectations in the Australian economy. The AER therefore considers that an averaging period ending on 5 September 2008 is likely to result in expected over compensation of the regulated firm relative to the cost of the efficient benchmark. The RBA recently noted that

481 CEG, *Rate of return and the averaging period*, op.cit. pp. 18–21.
482 Grundy, p. 4.

average business lending costs on outstanding loans have declined by around 230 basis points since the start of the monetary policy easing cycle.[483]

The expected return on debt appears to have increased relative to the benchmark risk–free rate due to tightening in credit markets and the perception of increased risks in these markets. This could explain a narrowing of the difference between the required return on debt and the required return on equity. Debt is a fixed nominal cash flow claim while equity has a residual claim that is insulated against inflation. Therefore, the risks facing debt and equity are different and the required returns will be different. The AER considers that to the extent there is a narrowing of the difference between the required return on debt and equity, it is driven primarily by the increased debt risk premiums. Such a change is consistent with the current global financial crisis which is primarily driven by a crisis in credit markets.

Comments regarding the accuracy of the Bloomberg data for calculating the cost of debt are considered by the AER in section 5.5.2 of this final decision.

C.6 Certainty and the averaging period

In its April 2008 report (prior to the draft decision), CEG noted that the main reason for the WACC parameters being set in the NER was the need for early certainty by the NSP about the rate of return to be earned and extending this logic to the averaging period would suggest an early period—even one that may be set before the AER's draft determination.[484] CEG reiterated the need for business certainty in its January 2009 report.

The AER does not agree that the main consideration for setting the WACC parameters was to provide the NSPs early rate of return certainty as interpreted by CEG. The AEMC's aim was to provide short–term stability regarding the WACC determination by reducing an important source of potential differences between regulatory decisions.[485] Contrary to CEG's interpretation, logically extending the AEMC's objective suggests that the averaging period should be consistent with the current AER practice as this would extend the intended regulatory certainty. Consistency with current regulatory practice is discussed in section C.7.

In the event that CEG's interpretation about early certainty is adopted, then it is akin to the regulator agreeing to set the regulated rate of return at whatever time the NSPs decide that is in their best interest to refinance debt/raise capital. This could create opportunities for 'gaming' the regulator. For example, an NSP can lock in an averaging period that it considers achieves the most advantageous rate of return early in the regulatory process based on its view of future interest rate movements but if its view transpires to be disadvantageous, expect the regulator to accept a different period later on in the regulatory process. As shown in figure C.1, in June 2008 when the AER received the NSPs' regulatory proposals, the interest rate yield curve was downward sloping. The downward sloping yield curve at that time reflects market

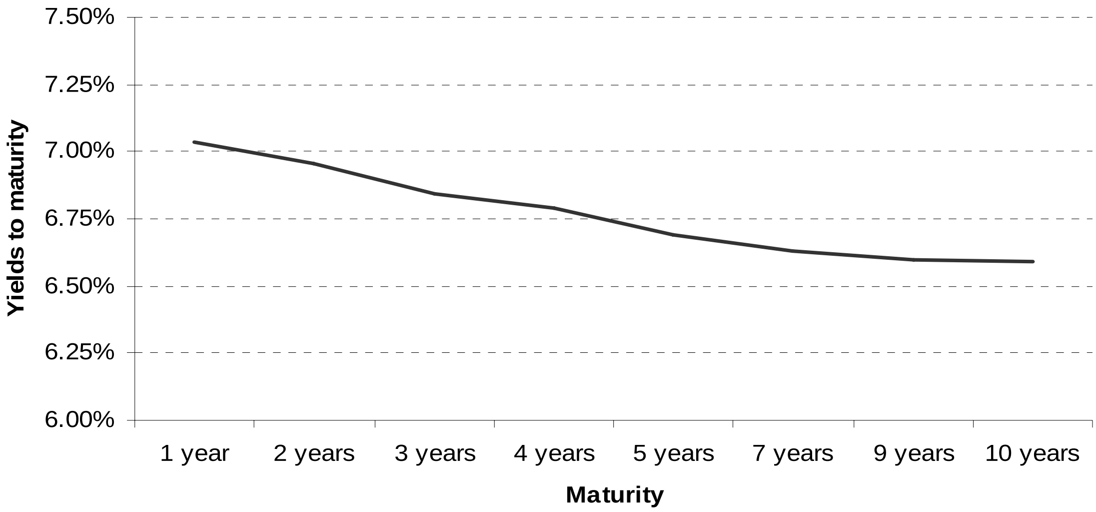
483 RBA, *Statement on monetary policy*, February 2009. Available: http://www.rba.gov.au/PublicationsAndResearch/StatementsOnMonetaryPolicy/Feb2009/domestic_financial_markets.html, viewed 13 February 2009.

484 CEG, *Nominal risk–free rate, debt risk premium and debt and equity raising costs*, April 2008, p. 5 and CEG, *Rate of return and the averaging period*, op.cit. p. 27.

485 AEMC, *Rule determination*, Rule No 2006 No. 18, p. 82.

expectations of lower interest rates in the future. Therefore, setting the risk–free rate based on an averaging period at that time would have lead to systematic ex ante overcompensation of firms relative to the efficient cost of capital and inconsistent with the forward looking nature of CAPM—that is, it would not result in an unbiased risk–free rate.

Figure C.1: June 2008 yield curve for CGS



Source: Bloomberg data and AER analysis.
Note: Yield curve is based on a simple average of daily yields during June 2008.

EnergyAustralia argued that the AER did not specify proximity of the proposed averaging period to either the final determination or commencement of the regulatory control period in its 2007 Powerlink decision and that Powerlink's proposal was premised on the consideration of business certainty.[486]

The AER notes that the 2007 Powerlink final decision was originally targeted for completion in December 2006. On this basis, the averaging period proposed by Powerlink upfront at the start of the regulatory process was intended to be consistent with the AER/ACCC practice of setting the period as close as practicable to the start of the next regulatory control period.[487] However, the final decision was delayed to June 2007. As the averaging period was agreed early in the review process, consistent with standard practice, the AER did not change the averaging period to take account of the delay with the final decision date.

The AER considers that the additional material put forward by the NSPs does not support the view that its decision on the agreed averaging periods was inconsistent with the NER.

486 EnergyAustralia, *Revised regulatory proposal*, attachment 8A, p. 4.
487 Powerlink, *Letter to AER – risk–free rate* — confidential, 7 December 2005.

C.7 Consistency with regulatory practice

The AER considers that given the evidence at the time, the additional material contained in the revised regulatory proposals do not justify a conclusion that the AER's decision to withhold agreement to the proposed averaging periods and consequently the agreed averaging periods were inconsistent with regulatory precedent. The AER notes the following:

- The approach is consistent with recent transmission determinations made under chapter 6A of the NER for ElectraNet and SP AusNet.[488]
- The AEMC's National Electricity Amendment (*Economic regulation of transmission services*), Rule 2006 No 18, rule determination recognised the need for consistency with the ACCC's WACC methodology and parameters contained in the ACCC's 2004 Statement of Regulatory Principles.[489]
- The AEMC's transmission rule (noted above) was adopted by the Standing Committee of Officials of the Ministerial Council on Energy (SCO) for the WACC in the transitional chapter 6 rules.[490]
- The AER's approach was recently enunciated in its WACC review issues paper released in August 2008.[491] It was noted that:

> The AER's current approach is to accept a proposed starting date to the averaging period which is as close as practically possible to the commencement of the regulatory control period, to ensure an unbiased estimate of the risk–free rate (and the corporate bond rate).[492]

- In the WACC review issues paper, the AER specifically asked whether the practice of accepting any averaging period of between 5 and 40 days and commencing as close as possible to the start of the regulatory control period should be reconsidered. In response, the Joint Industry Associations (JIA) consisting of the Energy Networks Association, Australian Pipeline Industry Association and Grid Australia stated that:

> The businesses are of the view that the current regulatory practice of averaging contained in the NER is acceptable.[493]

- JIA also submitted that the regulated businesses should have the discretion to select the start date and noted that continuing the current practice:

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488 AER, *ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008 and AER, *SP Ausnet transmission determination 2008–09 to 2013–14*, January 2008.

489 AEMC, *National Electricity Amendment (Economic regulation of transmission services) rule 2006 No 18, rule determination*, November 2006, pp. 85–86 and AEMC, *Draft rule determination, Draft national Electricity Amendment (Economic regulation of transmission services)*, 26 July 2006, pp. 56–57.

490 SCO, *Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution*, Explanatory Material, p. 44. Available: www.ret.gov.au/Documents/mce/emr/governance.
EnergyAustralia, *Supplementary submission on NER exposure draft*, 31 May 2007, attachment 1. Available: www.ret.gov.au/Documents/mce/emr/governance

491 AER, *Issues paper, review of the WACC parameters for electricity transmission and distribution*, August 2008.

492 ibid., p. 36.

493 Network Industry Submission, *AER issues paper–Review of the WACC parameters for electricity transmission and distribution*, September 2008, pp. 76–77.

- provides consistency with regulatory precedent thereby minimising regulatory risk
- provides consistency with existing practices arising from this in tapping and accessing debt and equity markets
- provides regulated electricity transmission and distribution businesses with an opportunity, but not an obligation, to raise a portion of the debt during the averaging period
- allows regulated electricity transmission and distribution businesses to build a debt profile of multiple debt financing to minimise risks.[494]

- The AER's WACC review draft decision formalised its current approach and proposed to retain the current NER methodology subject to only accepting an averaging period commencing as close as practically possible to the start of the regulatory control period.[495] This formalisation of the current approach was not objected to by JIA in its submissions on the WACC review draft decision.

C.8 NEL revenue and pricing principles

Revenue and pricing principles in the NEL state that an NSP should be provided with a reasonable opportunity to recover at least the efficient costs incurred in providing direct control services and complying with a regulatory obligation or making a regulatory payment.[496]

The NSPs submitted that the AER should have regard to whether the selection of the averaging period in determining the rate of return provides a reasonable opportunity to recover at least the efficient costs.[497]

Clause 6.5.2(b) of the transitional chapter 6 rules and clause 6A.6.2(b) of the NER prescribe the WACC methodology (including the CAPM) for calculating the regulated rate of return. The AER considers that the agreed averaging periods are consistent with finance theory. Moreover, the determined WACC is consistent with the NER and as intended moves commensurate with interest rate changes in the Australian economy which is also consistent with the NEL objective of promoting efficient investment. The fact that the risk–free rate is at (or close to) historical lows does not by itself mean that the resulting WACC does not provide a reasonable opportunity to recover the efficient costs of capital.

The AER notes that the WACC parameters are based on benchmarks and are part of the incentive framework. Therefore, the NSPs have an opportunity to achieve a higher rate of return by better managing their operating costs.

Under incentive regulation, firms generally receive the benefits and incur the cost of deviating from the efficient benchmark. Rewarding firms for losses incurred when

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494 Network Industry Submission, pp. 76–77.

495 AER, *Explanatory statement, electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters*, December 2008, p. 133.

496 NEL, clause 7A(2).

497 EnergyAustralia, *Revised regulatory proposal*, p. 58.

they deviate from the efficient benchmark may encourage firms to act in this manner as they will expect to incur any upside from taking on risk and not suffer from the downside. An incentive mechanism with such expectations built in may encourage excessive risk taking inconsistent with the revenue and pricing principles in the NEL that require incentives to promote economic efficiency.[498]

Given the significant future capex programs and the evolving changes in the Australian economy in 2009, the AER requested confirmation from the NSPs on whether they are able to fund their respective capital programs. In response, the NSPs confirmed their ability to fund the capital programs for the next regulatory control period.[499]

Generally, the AER does not place much weight on WACC comparisons across regulatory control periods. However, in the absence of information supporting the NSPs' assertion that the agreed averaging period for setting the risk–free rate will result in inconsistency with the NEL revenue and pricing principles, a comparison was undertaken.

The IPART and the ICRC determined a pre–tax real WACC of 7.0 per cent applicable to the NSW DNSPs and ActewAGL respectively for the current regulatory control period.[500] This compares with an equivalent pre–tax real WACC of about 6.8-6.9 per cent for the next regulatory control period under this final decision.[501] For TransGrid's/Energy Australia's —transmission and Transend's current regulatory control period the ACCC determined a nominal vanilla WACC of 8.92 and 8.80 per cent respectively and these compare with a nominal vanilla WACC of 9.08 per cent and 8.80 per cent for the next regulatory control period.[502] The AER notes that during the period December 2003 to March 2005 the RBA's cash rate was between 5.00 – 5.25 per cent whereas during the agreed averaging period it was at 3.25 per cent. [503] Noting this reduction in the cash rate commensurate with a softening in economic growth, the AER considers that the NSPs' WACC for the next regulatory control period (although lower) is reasonable compared to the WACC in the current regulatory period.[504]

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498 NEL, clause 7A(3).

499 Country Energy, letter to the AER, *Deliverability of capital expenditure program – 1 July 2009 to 30 June 2014*, 18 February 2009; EnergyAustralia, letter to the AER - *Deliverability of capital expenditure program*, 17 February 2009; Integral Energy, letter to the AER, *Deliverability of capital expenditure program – 1 July 2009 to 30 June 2014*, 18 February 2009; TransGrid, letter to the AER, *Deliverability of capital expenditure program – 1 July 2009 to 30 June 2014*, 27 February 2009; and Transend, letter to the AER, *Deliverability of capital expenditure program – 1 July 2009 to 30 June 2014*, 17 February 2009.

500 IPART, *NSW electricity distribution pricing 2004/05 to 2008/09, final report*, June 2004, pp. 217–218 and ICRC, *Investigation into prices for electricity distribution services in the ACT, final decision*, March 2004, p. 70.

501 This varies depending on the effective tax rate modelled for each NSP.

502 ACCC, *Tasmanian transmission network revenue cap, 2004 – 2008/09, final decision*, December 2003 and ACCC, *NSW & ACT transmission revenue cap TransGrid 2004–05 to 2008–09, final decision*, April 2005.

503 RBA, Cash rate target, viewed 23 March 2009. Available: <http://www.rba.gov.au/Statistics/cashrate_target.html>

504 On 7 April 2009 the RBA further reduced the cash rate to 3.0 per cent.

Overall, the AER considers that the NSPs are not being deprived of a reasonable opportunity to recover their efficient cost of capital.

C.9 Conclusion

Based on the above reasons the AER considers that its decision to withhold agreement to the averaging periods nominated in the NSPs' regulatory proposals was reasonable and that its agreed averaging periods are consistent with finance theory, regulatory practice, the NER and NEL.

Appendix D: Benchmarking

D.1 Introduction

The purpose of this appendix is to conduct a high-level comparative analysis (benchmarking[505]) of the expenditure proposed by Transend relative to expenditure undertaken by other TNSPs in Australia.

D.2 Comparability

The AER recognises that not all TNSPs are the same. In attempting to benchmark Transend against other TNSPs, the AER notes that TNSPs vary in size, physical operating environments, climate, customer density, geographic factors, ownership, asset strategies and jurisdictional responsibilities and accountabilities. These differences can impact on the requirements for expenditure so comparisons must be conducted with caution.

It is important to note that the benchmarking included in this appendix is not intended to represent a comprehensive study but instead aims to provide a high-level ‘sense check’ on Transend’s revenue proposal.

D.3 Transend’s Transmission System

The AER has undertaken a basic comparative analysis of the present (allowed) expenditure levels for both opex and capex.

The operational model for transmission in Australia does present some challenges for cross sectional benchmarking of Transend. In particular:

- Transend has both transmission and other assets[506] which may be considered distribution in other jurisdiction and this may distort the analysis/outcome.
- Some transmission businesses in the NEM (including Transend) have responsibility for planning and augmentation as well as replacement, refurbishment and maintenance of ageing assets. However, in Victoria, the network asset owner (SP AusNet) is a separate entity from the investment decision maker (VENCorp), which is unique arrangement within the NEM. This further complicates benchmarking of Australian TNSPs.

Six of Australia’s TNSPs are included in this analysis and an overview of scale and business conditions of the TNSPs is provided in table D.1 below.

505 Benchmarking is carried out to compare the level of costs for the subject business with those of similar businesses elsewhere in order to determine on an informed basis whether the costs are reasonable.

506 The definition of transmission assets in Tasmania includes assets which may be classified as distribution (assets operating at lower voltages) in other jurisdictions

Table D.1: Overview of Australian TNSPs included in comparative analysis

TNSP	Network length (km)	Number of sub-stations	Peak summer demand[507]	6-year summer demand growth forecast (M50, 08/09-14/15)(MW)	Medium growth annual energy forecast (GWH)
Transend	3,654	54	1,381	145	10,221
Powerlink	12,132	98	9,461	2,291	51,058
TransGrid	12,489	82	13,820	2,270	75,710
SP AusNet	6,553	44	9,198	1,096	47,599
ElectraNet	5,611	76	2,990	376	12,631
EnergyAustralia*	903.3	26	Na	Na	Na

*Energy Australia will be re-classified as a DNSP in July 2009

D.4 Operational Benchmarking

The operational benchmarks show how intensively Transend is operated compared to the other Australian TNSPs. Table D.2 shows the line length per peak load and the peak load per substation. The data in this table indicates that Transend uses its network length and substations quite intensively and in this regard is most similar to ElectraNet.

Table D.2 – Transmission operational benchmarks

Transmission Network	Network Length/ Peak Load	No. Substations/Peak Load
Transend	1.696	39.09
Powerlink	1.448	84.64
TransGrid	0.939	162.10
SPA/VENCorp	0.751	198.41
ElectraNet	1.927	38.66

D.4.1 Capex benchmarking

In order to account for differences in size and business conditions of the transmission networks, the AER has plotted the capital costs of TNSPs against the key cost drivers such as size (expressed by the value of the TNSP's average RAB, length of network, number of substations, MW of peak load and MWh of energy sent out) and load density (expressed by peak load per km of network and peak load per substation).

Capital expenditure shown is the average annual capital expenditure during the most recent regulatory period in each jurisdiction (2006/07). Values are sourced from publicly available regulatory determinations and AER regulatory reports.

[507] NEMCO, *Statement of Opportunities 2007*, November 2007.

Figure D.1 (below) shows annual average capex for each business as a proportion of average RAB value, plotted against average RAB value. The measure for Transend is approximately 13.4 per cent compared to the combined SP AusNet/VENCorp transmission network of approximately 5.5 per cent. Transend is relatively high in this measure, but the reason for this is Transend's capex values are on a as "commissioned basis" rather than as "incurred basis". Transend is higher than ElectraNet but has similar operating conditions as shown by table D.2 above. Given that Transend owns assets which may be classified as distribution in other jurisdictions, it is not surprising that it may have higher capex and opex spending[508] although it is difficult to quantify the magnitude.

Figure D.1: Average annual capital expenditure as a proportion of average RAB value

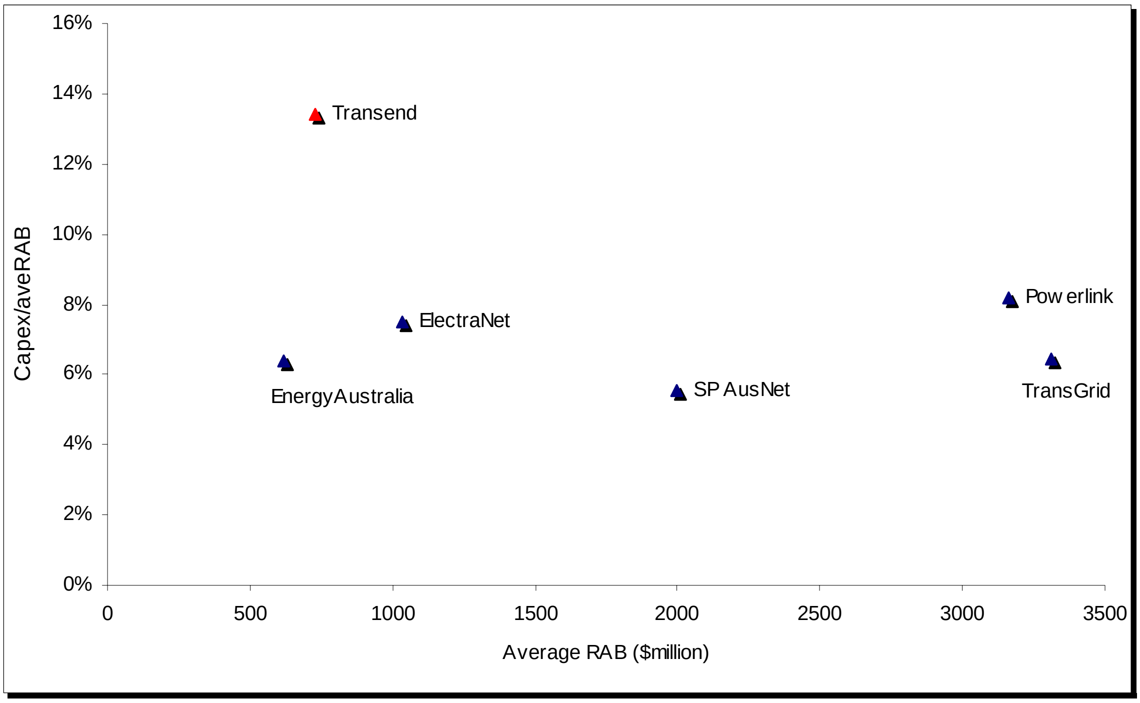
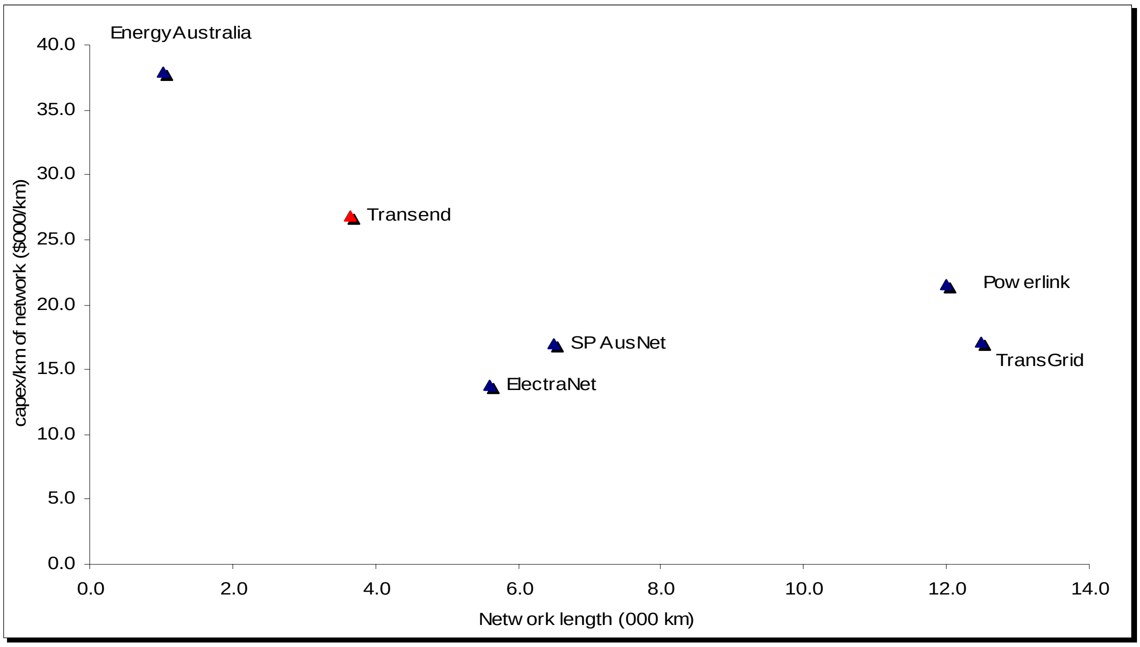


Figure D.2 shows capex per kilometre length of circuit (line) as a function of network length (km of line). The proposed capex for the Transend networks is seen to be higher than other benchmarked networks, with the exception of EnergyAustralia. As mentioned above, there are limitations in this benchmark as it does not reflect Transend's actual capex. In addition, EnergyAustralia has a shorter transmission network length which makes it an outlier in this benchmark.

508 Smaller substations may be relatively more expensive to maintain because of economies of scale.

Figure D.2: Capital expenditure as a function of network length



When using time series data (figure D.3), it appears that Transend does not significantly differ from other TNSPs on this benchmark. Having said this, Transend has indicated that changes in planning and regulatory requirements led to the deferral of a significant capital project (the Waddamana–Lindisfarne transmission line project) from the earlier years to late 2007. As a result, there were consequential delays in other projects (such as Creek Road and Tungatinah substation redevelopments) which allowed Transend to prioritise its capital spend within the ACCC allowance to undertake asset replacement work.

Figure D.3: Capital expenditure as a function of network length (time series)

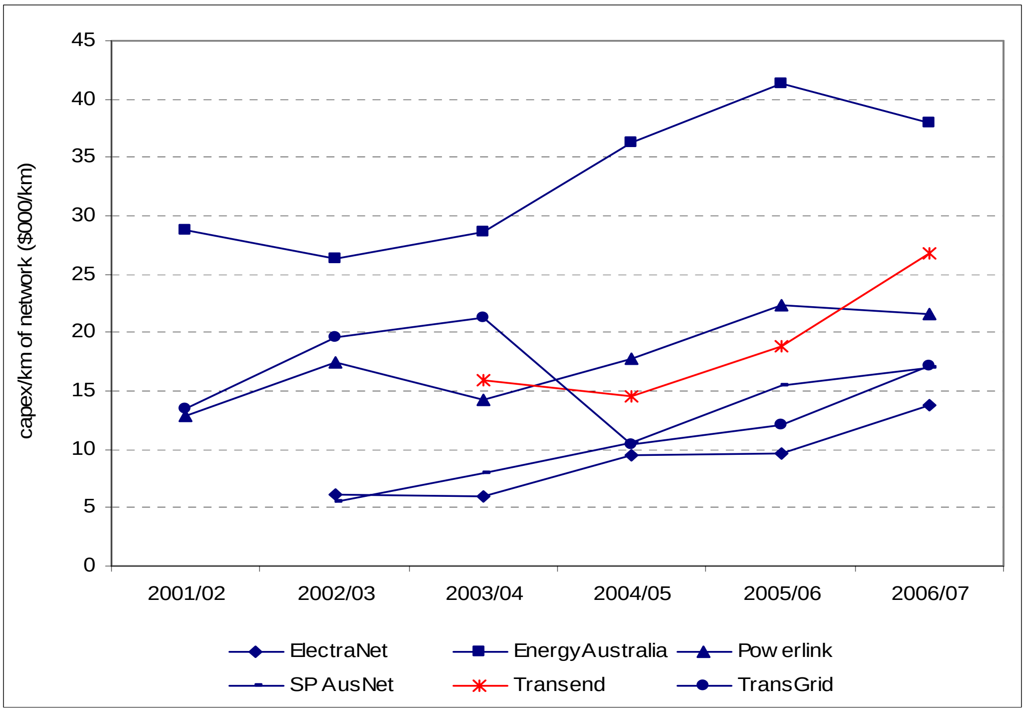
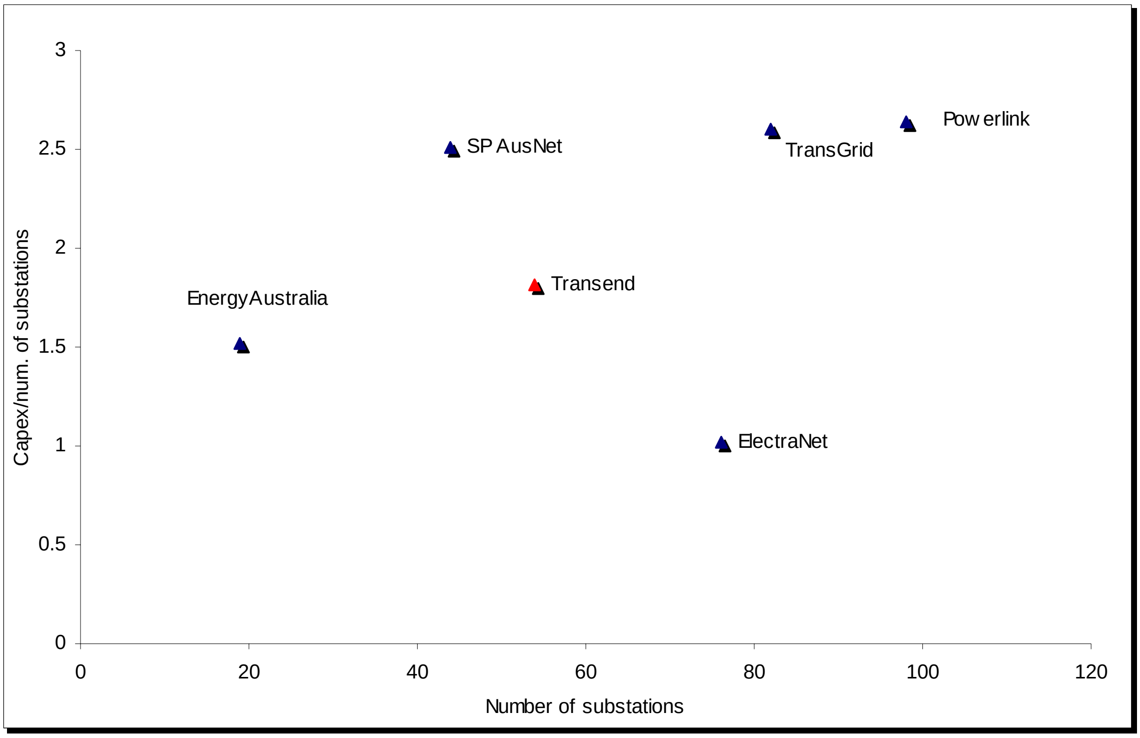


Figure D.4 shows the capex per substation as a function of the number of substations. The capex for Transend is seen to be well below average and slightly above ElectraNet. This result reflects the comparatively low number of high capital value substations which is a feature of the Victorian electricity transmission network. Therefore, the number of substations does not necessarily provide complete information for cross sectional benchmarking.

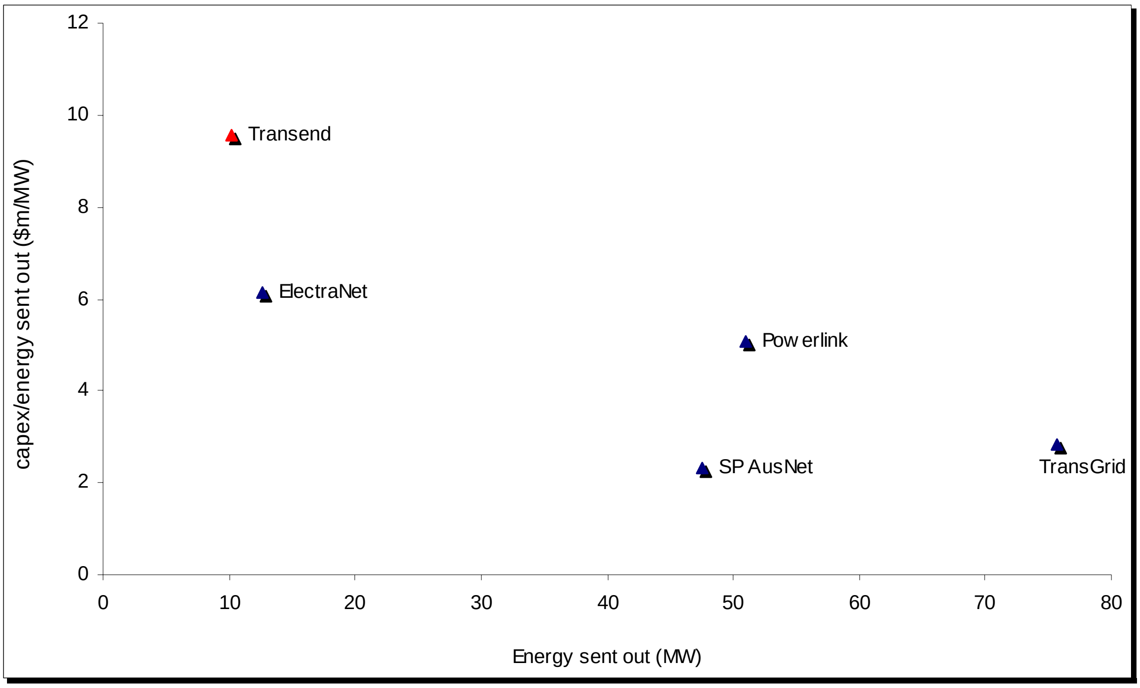
Figure D.4 – Capital expenditure as a function of substations



Jurisdictions with a lower network and load density (average peak load per substation) such as Tasmania and South Australia are seen to have a lower capex per substation ratio. This is due to smaller substations being less expensive to build.

Figure D.5 below shows capex per MWh of transmitted energy (as a function of transmitted energy). The capex for Transend is shown to be higher than other TNSPs.

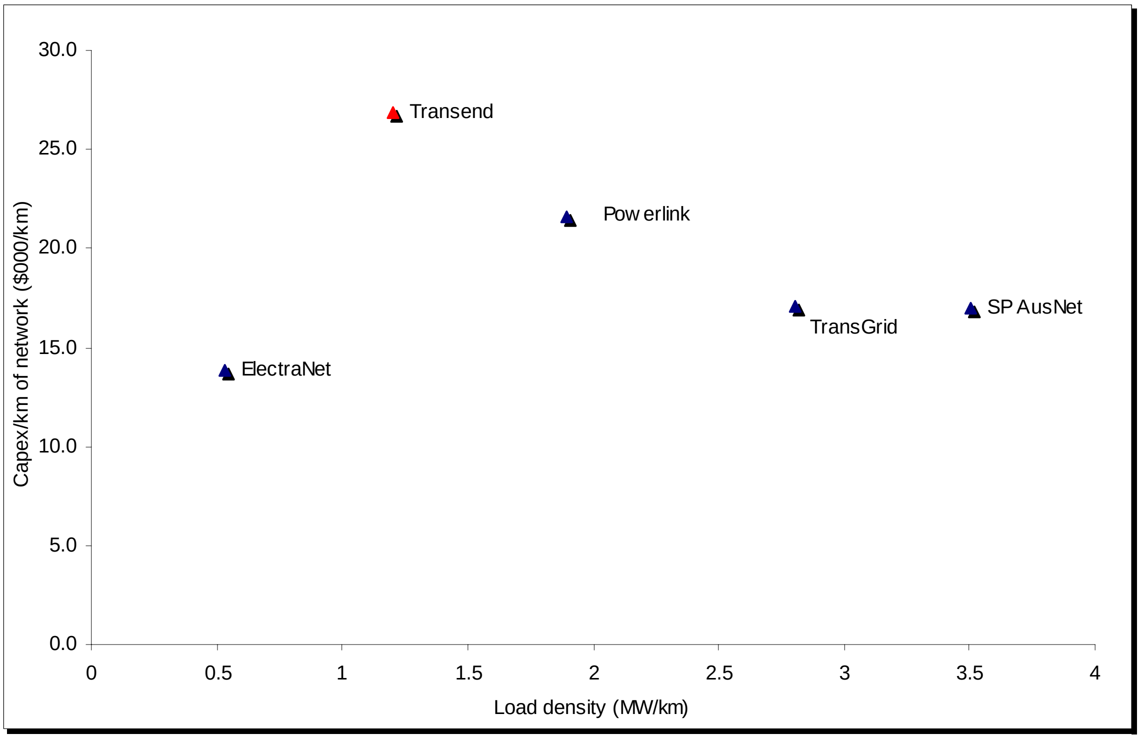
Figure D.5: Capital expenditure per MWh of transmitted energy



*information for EnergyAustralia was not available

Figure D.6 shows capex per substation as a function of load density (expressed in MW of peak load per substation). The result for Transend appears to be higher than other network businesses.

Figure D.6: Capex per substation as a function of load density (MW/substation)



*information for EnergyAustralia was not available

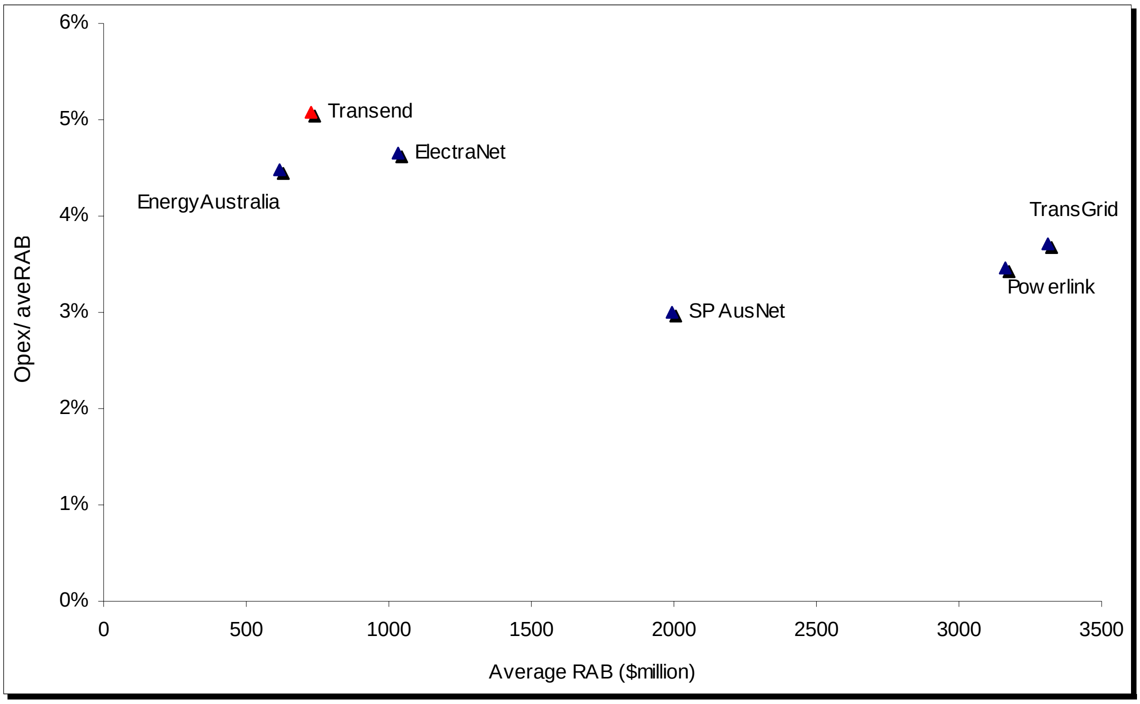
D.4.2 Opex benchmarking

In order to consider differences in both business size and business conditions, the AER has plotted Transend's opex against the key cost drivers such as size (expressed by average RAB value, length of network and number of substations).

Figure D.7 shows opex as a proportion of average RAB value plotted against the RAB value for each of the sample transmission companies. As might be expected, the indicative trend is for opex (as a proportion of RAB value) to decrease as the asset base increases. This is likely to reflect the fixed costs of operations and maintenance, and hence the economies of scale available to the larger businesses.

The results for Transend show it was higher than average. However, it should be noted that this is post-NEM entry for Transend, and Transend was faced by higher costs resulting from the introduction of new functions and obligations.

Figure D.7: Operating expenditure as a proportion of average RAB



The AER also notes the time series analysis conducted by WorleyParsons and its observations[509]:

In comparison to the other TNSP's, Transend has a higher level of opex per unit RAB. However, WorleyParsons considers that this is due to the unique or atypical nature of the Transend network (and possibly a low valuation of the RAB) rather than poor efficiency.

It should be noted that the data for Transend is not entirely consistent across both the current regulatory control period and the next regulatory control Period. The inconsistency (which is quite minor) arises because of a changed AER ruling. That is,

509 WorleyParsons, *Review of the Transend transmission network revenue proposal 2009-2014: An independent review prepared for the AER,* October 2008, page 215.

in the current regulatory control period, capex is measured on an "as commissioned" basis whereas capex in the next regulatory control period is measured on an "as incurred" basis. However, given the amount of WIP as compared to the total RAB, this inconsistency is not material for the purposes of the above comparisons.

Transend's forecast opex as compared to the average RAB shows an efficiency improvement of about 1.1 per cent, that is, a reduction from 5.1 per cent to 4 per cent.

Figure D.8 (below) shows opex per kilometre length of circuit (line) as a function of network length (km of line). This reflects the fixed costs of operations and maintenance, and hence the economies of scale available to the larger businesses. The proposed opex for the Transend transmission business is therefore comparable to other TNSPs.

Figure D.8: Operating expenditure as a function of network length

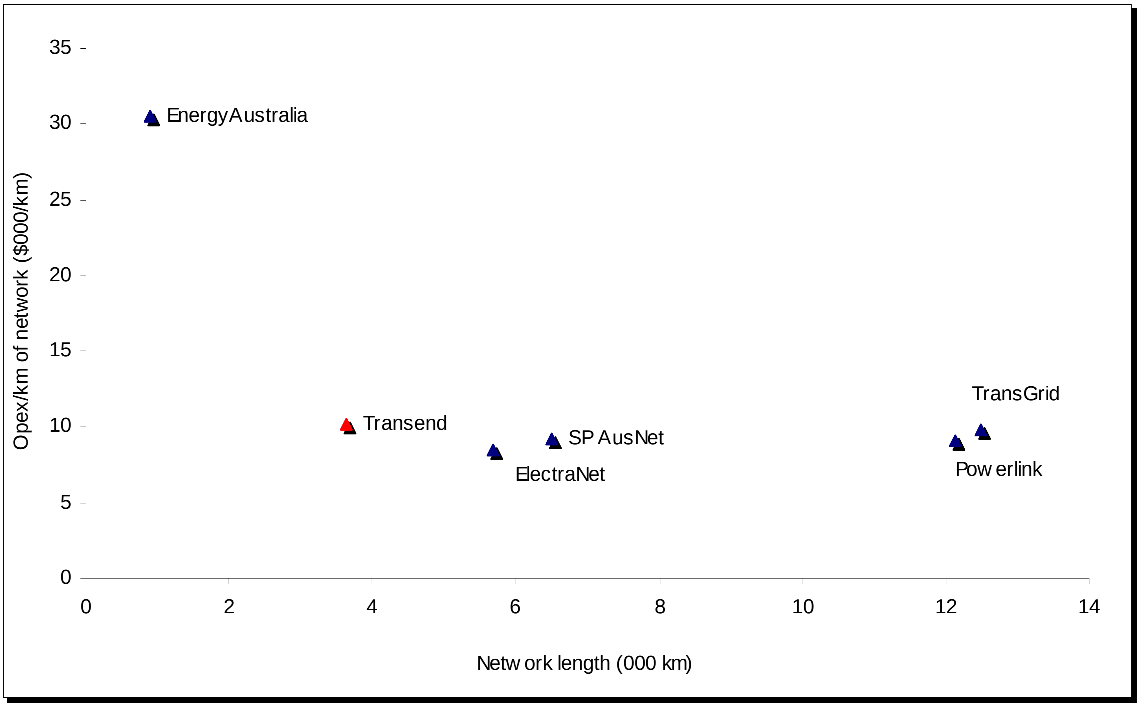
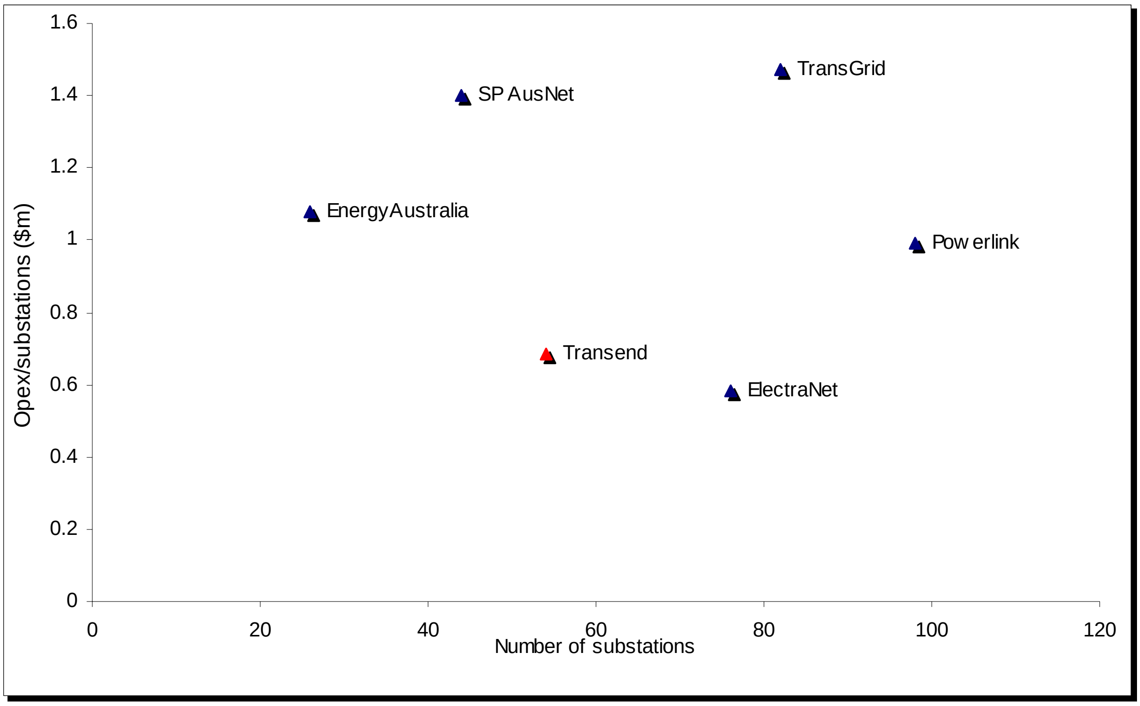


Figure D.9 shows opex per transmission substation as a function of the number of transmission substations. Transend and ElectraNet are seen to have comparatively low operating costs per substation, which partly reflects the comparatively small service area per substation and the comparatively small substation size (and hence the lower operations and maintenance liability per substation).

Figure D.9: Operating expenditure as a function of the number of substations



D.5 Conclusion and recommendations

When combined with the benchmarking analysis conducted by WorleyParsons,[510] Transend's expenditure levels are similar to other TNSPs, especially with regards to opex. In capex Transend's performance is lower than other TNSPs but it was noted that it would be difficult to assess Transend against other TNSPs due to the differing composition of its assets base relative to its peers.

Given that this is the case, the AER considers that the capex ratios do little to assist in assessing relative efficiencies between TNSPs. The position of Transend relative to the other TNSPs is summarised the table below.

510 WorleyParsons, *Review of the Transend revenue proposal*, op. cit. pp 146-152 and 214-224.

Table D.3 – Performance relative to other TNSPs

Indicator	Relative position
Network length/peak load	Close to top of the range
Number of substations/peak load	Close to the bottom of the range
Capex as % of ave RAB	At the top of the range
Capex /km network length	Close to the top of the range
Capex /km network length (time series)	In the middle of the range
Capex/substations	In the middle of the range
Capex/energy transmitted	At the top of the range
Capex per substation as a function of load density	At the top of the range
Opex as % of ave RAB	At the top of the range
Opex/km of network length	In the middle of the range
Opex/substations	Close to the bottom of the range

As mentioned earlier, while benchmarking can offer a useful means of comparing the relative performance of TNSPs, it is often open to various interpretations. As such, differences in environment, network configurations, voltage levels, connected generation, connected loads and previous technical decisions, mean that definitive comparisons can be difficult to make.

Regarding the usefulness of the ITOMS information provided by Transend, the AER also noted the limitations and the weakness of this information. Although the ITOMS data does indicate a time series of Transend's performance over time, the AER considered that its performance relative to its peers should not be relied upon, especially as the nature of the business was different to its peers and its circumstances had changed materially following NEM entry. Furthermore, given that ITOMS benchmarking is not binding in nature, is voluntary, and the disclosure requirement for its usage is restricted, the AER did not consider it to sufficiently reliable or determinative for use in this benchmarking exercise.

Appendix E: Benchmark debt and equity raising costs

The AER concurrently assessed the revised revenue proposals of two TNSPs (TransGrid and Transend) and the revised regulatory proposals of four DNSPs (ActewAGL, Country Energy, EnergyAustralia and Integral Energy). Within this appendix these six regulated businesses are collectively referred to as the network service providers (NSPs). For convenience, within this appendix the term regulatory proposal should be taken to include the term revenue proposal, where the AER is referring to the NSPs. Within this appendix the AER has also used the term draft decision to refer to any and all of the relevant draft decisions affecting the NSPs. Where it has been necessary to refer to a draft decision for just one of the NSPs, within this appendix the AER has identified the specific business when referencing the draft decision, rather than applying the generic term draft decision, as defined in the shortened forms.

E.1 Debt raising costs

E.1.1.1 Rationale for joint consideration

The NSPs have proposed the same unit rate to determine the allowance for debt raising costs, a total of 15.5 basis points per annum (bppa) to be applied to the debt component of the regulatory asset base (RAB) each year.[511] This total unit rate is comprised of 3.0 bppa for indirect debt raising costs and 12.5 bppa for direct debt raising costs.

The shared position of the NSPs is reinforced by reliance on substantially the same consultant reports. In the regulatory proposals submitted by five of the six NSPs (excluding ActewAGL), variants of a Competition Economists Group (CEG) consultancy report were submitted.[512] In the revised regulatory proposals, a report by CEG is referenced and submitted by all six NSPs—that is, all submitted versions are identical.[513] TransGrid and EnergyAustralia both submitted an additional report by Tony Carlton, from the University of NSW, although there are some variations

511 TransGrid, *Revised revenue proposal*, p. 78; Transend, *Revised revenue proposal*, p. 57; Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Revised regulatory proposal*, p. 107; Integral Energy, *Revised regulatory proposal*, p. 43; and ActewAGL, *Revised regulatory proposal*, p. 33.

512 CEG, *Nominal risk free rate, debt risk premium and debt and equity raising costs for TransGrid*, May 2008; CEG, *Nominal risk free rate and debt and equity raising costs for Transend*, May 2008; CEG, *Nominal risk free rate, debt risk premium and debt and equity raising costs for Country Energy*, May 2008; CEG, *Nominal risk free rate, debt risk premium and debt and equity raising costs for EnergyAustralia*, May 2008; CEG, *Nominal risk free rate, debt risk premium and debt and equity raising costs for Integral Energy*, April 2008.

513 CEG, *Debt and equity raising costs: A response to the AER 2008 draft decisions for electricity distribution and transmission*, January 2009. Cited by TransGrid, *Revised revenue proposal*, p. 77; Transend, *Revised revenue proposal*, p. 57; Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Revised regulatory proposal*, p. 105; Integral Energy, *Revised regulatory proposal*, p. 43 and ActewAGL, *Revised regulatory proposal*, p. 33.

between the two versions.[514] Further, EnergyAustralia's submission requested that all reports and supporting documents which it had submitted as part of its regulatory proposal and revised regulatory proposal be considered by the AER in making its final determination for all the NSPs.[515]

Other relevant submissions were also received by the AER, from the following organisations:

- TransGrid—a report by the Strategic Finance Group (SFG)[516]
- Powerlink—regarding aspects of the draft decision for TransGrid[517]
- Joint Industry Association (JIA)— including a report by CEG that merges parts of the May 2008 and January 2009 CEG reports with new analysis (note that this report was additionally submitted as an attachment to EnergyAustralia's revised proposal).[518]

Due to the consistency between the opex provisions of the NER under which the debt raising cost proposals are assessed, the NSPs' revised regulatory proposals and the supporting consultancy reports, the AER jointly assessed the debt raising costs of the NSPs. The AER's analysis and conclusions are contained in this appendix, which is reproduced in each of the AER's final decisions for the NSPs.

The AER considers that it is important for a consistent methodology to determine the appropriate allowance for benchmark debt raising costs to be applied in its final decisions for the NSPs.[519]

E.1.1.2 Rationale for draft decisions

In making the draft decisions, the AER's consideration of debt raising costs took account of the requirements of the NER. This includes the requirement that forecast opex for the NSPs reasonably reflects the efficient costs that a prudent operator in the circumstances of the relevant NSP would require to achieve the opex objectives.[520]

The draft decisions were consistent with the relevant parameter values specified in the NER, including that the benchmark firm maintains a 60 per cent gearing ratio and issues debt at a BBB+ credit rating.[521]

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514 Carlton, T., *Indirect costs of equity and debt raising: Report prepared for EnergyAustralia*, 12 January 2009; and Carlton, T., *Indirect costs of equity and debt raising: Report prepared for TransGrid*, 12 January 2009.

515 EnergyAustralia, *Submission on other network service providers*, 16 February 2009.

516 SFG, *Debt and equity issuance costs for a benchmark transmission business*, 20 March 2009.

517 Powerlink, *Draft decision: TransGrid transmission determination 2009–10 to 2013–14*, 16 February 2009.

518 JIA, *Network Industry submission: Debt and equity raising costs*, 11 November 2008 and CEG, *Debt and equity raising costs: A report for the APIA, ENA and Grid Australia*, 11 November 2008.

519 This approach is essentially the same as that employed by the AER for its draft decisions.

520 For DNSPs, see clause 6.5.6(c)(2) of the transitional chapter 6 rules. For TNSPs, see clause 6A.6.6(c)(2)of the NER.

521 AER, *TransGrid draft decision*, p. 137; AER, *Transend draft decision*, p. 190; AER, *NSW DNSP draft decision*, p. 186 and AER, *ACT draft decision*, p. 107.

Using the parameters specified in the NER, the AER constructed a model of the methodology by which a benchmark firm issues debt. Throughout this appendix the benchmark firm is a reference to a benchmark efficient NSP that is a pure play regulated electricity network operating in Australia without parent ownership. Assumptions about how such a benchmark firm issues debt were stated in the draft decisions. For example:

- the benchmark firm was assumed to issue public debt in the Australian market, in order to maintain consistency with the domestic capital asset pricing model (CAPM) that is applied to determine the regulated rate of return.[522]
- the debt was assumed to be raised in order to fund organic growth, rather than acquisitions or non–core investments, as the benchmark firm does not undertake such activities.[523]

The NSPs challenged the AER's assumption regarding the issuance of public debt in the Australian market and consistency with the domestic CAPM framework in their revised regulatory proposals. This is discussed below. Other assumptions (stated above) made by the AER in its modelling of the benchmark debt issue were not challenged by the NSPs, and accordingly, the AER considers that these assumptions remain valid for this final decision.

E.1.1.3 Indirect costs of debt raising

The AER rejected the proposed 3 bppa allowance for indirect debt raising costs (also known as underpricing) in the draft decisions.[524] All of the NSPs rejected the draft decision on this issue and resubmitted[525] the 3 bppa indirect cost allowance in their revised regulatory proposals.[526] The NSPs referred to consultant reports submitted as part of their revised regulatory proposals to justify the claim for indirect costs of debt raising.

Interpreting the NER prescribed BBB+ credit rating

The AER notes that the NER specifies:[527]

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522 AER, *TransGrid draft decision*, p. 137; AER, *Transend draft decision*, p. 191; AER, *NSW DNSP draft decision*, p. 186 and AER, *ACT draft decision*, p. 105.

523 AER, *TransGrid draft decision*, p. 136; AER, *Transend draft decision*, p. 188; AER, *NSW DNSP draft decision*, p. 185 and AER, *ACT draft decision*, p. 105.

524 AER, *TransGrid draft decision*, pp. 137–8; AER, *Transend draft decision*, pp. 189–190 and AER, *NSW DNSP draft decision*, pp. 185–187. Note that indirect costs were not included as part of the original ActewAGL proposal, and so were not rejected in the ACT draft decision.

525 In the case of ActewAGL, this was not a resubmission but rather submission for the first time. The AER notes that the NER restricts the presentation of material in a revised regulatory proposal to matters addressed in the draft decision, and that this would ordinarily prevent ActewAGL from making such a methodological shift between regulatory proposal and revised regulatory proposal. However, the AER considers that regulatory consistency is paramount on this issue, such that the decision made for all other NSPs will be applied to ActewAGL as well.

526 TransGrid, *Revised revenue proposal*, p. 78; Transend, *Revised revenue proposal*, p. 57; Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Revised regulatory proposal*, p. 107; Integral Energy, *Revised regulatory proposal*, p. 43 and ActewAGL, *Revised regulatory proposal*, p. 33.

527 The clause cited here applies to DNSPs, see clause 6.5.2(e) of the transitional chapter 6 rules. For TNSPs, the relevant clause is almost identical; see clause 6A.6.2(e) of the NER: 'The debt risk premium for a regulatory control period is the premium determined for that regulatory

> The debt risk premium for a regulatory control period is the premium determined for that regulatory control period by the AER as the margin between the 10 year commonwealth annualised bond rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity of 10 years and a credit rating of BBB+ from Standard and Poor's.

The AER observes this clause when it determines the debt risk premium associated with assumed debt issuance of the benchmark firm. To estimate the BBB+ benchmark corporate bond rate, the AER applies an established methodology based on the use of Bloomberg fair yield curves. CEG examined this methodology, and endorsed its use in its report accompanying the regulatory proposals:[528]

> In our opinion this approach is reasonable and the AER has shown that it does not result in a material error or an obvious bias (at least when measured against recent history).

CEG also tested the AER's methodology against an alternative approach and found the AER's methodology to be superior. In the draft decisions, the AER considered that the Bloomberg fair yield curves were therefore accepted as the best estimate of the cost of debt for the benchmark BBB+ debt issue.[529]

The AER notes that, in the revised regulatory proposals, issues have been raised in relation to the Bloomberg and CBASpectrum data sources used for establishing the debt risk premium. The AER's consideration of these issues is set out in section 11.5.2 of this final decision.

The AER notes that, although there is general agreement on the existence of direct costs of raising debt, CEG claim that additional indirect debt raising costs exist. CEG defined indirect costs in terms of underpricing, stating that:[530]

> Underpricing is a cost to all businesses who, in order to ensure the success of a debt issue, need to issue debt at a discount to the price it subsequently trades. This is true for all firms irrespective of their credit rating.

This explanation for underpricing—that it is required to sell debt—was explicitly mentioned by the NSPs in their revised regulatory proposals.[531]

For debt issues, CEG stated that there is a simple relationship between yield and price:[532]

> In the case of debt, a lower price implies a higher interest rate.

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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 Poor's and a maturity equal to that used to derive the nominal risk free rate.'

528 CEG, May 2008 (TransGrid), p. 7, paragraph 13; CEG, May 2008 (Transend), p. 7, paragraph 14; CEG, May 2008 (Country Energy), p. 7, paragraph 14; CEG, May 2008 (EnergyAustralia), p. 4, paragraph 14 and CEG, April 2008 (Integral Energy), p. 7, paragraph 13.

529 AER, *TransGrid draft decision*, pp. 93–94; AER, *Transend draft decision*, pp. 150–151; AER, *NSW DNSP draft decision*, pp. 225–226 and AER, *ACT draft decision*, pp. 137–138.

530 CEG, January 2009, p. 45, paragraph 150.

531 For example, see EnergyAustralia, *Revised regulatory proposal*, p. 106 and TransGrid, *Revised revenue proposal*, p. 78.

532 CEG, January 2009, p. 44, paragraph 149.

The AER further notes that Associate Professor Handley highlighted the key issue that distinguishes debt underpricing from equity underpricing:[533]

> …if a firm issues debt securities at a discount to the fair market price then there is a [sic] immediate gain to the new investors (who acquire the securities at a lower price) and an immediate cost to the firm in the form of lower proceeds received from the issue. In other words, unlike with equity securities, the higher the underpricing the lower the proceeds raised at the time of issue.

That is, Associate Professor Handley considered that if such underpricing exists, it will be included in measures of yield, in the manner of all other costs of debt. The AER therefore considers that the key issue is whether its approach to estimating the cost of debt for the benchmark regulated firm encapsulates the 'underpricing' effects.

The AER considers that the use of fair yield curves represent the best estimate of the expected cost of debt. Systematic underpricing, such as that proposed by CEG as applying to all firms irrespective of credit rating, should be readily detected and included in the fair yield curves. The AER considers that on these grounds, no allowance for underpricing is justified, taking into account the views of Associate Professor Handley:[534]

> In summary, assuming allowed revenues are determined using an appropriate estimate of the cost of debt, and noting that both the AER and CEG believe this to be the case, then it is my view that, underpricing should not be allowed as a cost of raising debt capital.

This is consistent with the draft decisions, which stated that:[535]

> 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.

The AER considers that granting an indirect cost allowance on top of an efficient benchmark measure of the BBB+ cost of debt would be double counting, and systematically allowing a higher rate of return than that required by the NER. Accordingly, the AER considers that to the extent indirect debt raising costs represent a rate of return in excess of NER requirements, the proposed allowance for indirect debt raising costs is inappropriate.

Absence of supporting empirical evidence

TransGrid stated that there is a 'significant body of empirical evidence demonstrating that underpricing is a cost to businesses raising debt.'[536] CEG stated in similar terms that:[537]

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533 Handley, J. C., *A note on the costs of raising debt and equity capital*, 12 April 2009, p. 15.

534 Handley, April 2009, p. 17.

535 AER, *TransGrid draft decision*, p. 137; AER, *NSW DNSP draft decision*, p. 186; and AER, *Transend draft decision*, p. 190.

536 TransGrid, *Revised revenue proposal*, p. 78.

537 CEG, January 2009, p. 45, paragraph 150.

> The finance literature we have referred to has demonstrated that the answer to this empirical question is that underpricing does exist. **This empirical fact cannot be assumed away**. [emphasis in original]

The AER does not consider that the NSPs or their consultants on this issue (SFG,[538] Carlton and CEG) have submitted reliable evidence that debt underpricing exists.

SFG discussed conceptual issues relating to indirect equity raising costs at length, and then argued that these reasons 'apply equally to the issuance of debt and equity capital'.[539] The AER considers that such a claim is not supported, in that the mechanistic difference between equity raising and debt raising is sufficient to invalidate such a combined approach.[540] The AER observes that for empirical measures of the cost of raising debt, SFG referred directly to the CEG report, and provided no independent analysis.[541]

Carlton noted several theoretical reasons for indirect debt raising costs. He also mentioned two research papers on the subject, and argued that there are differences between the US and Australian debt markets.[542] However, the CEG reports encompass all of Carlton's arguments, and present greater detail on most aspects. The AER therefore considers that thorough consideration of the CEG reports adequately addresses the issues covered by Carlton.

CEG's argument on indirect debt raising costs relied on a working paper by Saunders, Palia and Kim.[543] The authors of this paper do not find empirical evidence of underpricing in debt issues, stating:[544]

> …given the difficulty of generating one–day returns [a measure of underpricing] for a sufficient number of debt IPOs [initial public offerings], we did not directly calculate one–day returns.

That is, Saunders et al did not examine the existence of debt underpricing, as they did not possess the data to investigate this question.

The AER notes that Saunders et al referred to an earlier paper, by Datta, Datta and Patel as an anecdotal aside on debt underpricing.[545] CEG cited the Saunders et al working paper in its first report, stating:[546]

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538 The AER notes that the SFG report was received on 21 March 2009, more than one month after submissions closed on 16 February 2009. In this instance, the AER was able to consider all material within the SFG report on debt raising costs despite the late submission of this report. However, the AER notes that it has the right to reject late submissions, particularly where there is insufficient time to afford due consideration to the arguments therein.

539 SFG, March 2009, p. 12.

540 This point is also made by Handley, April 2009, p. 4.

541 SFG, March 2009, p. 17.

542 Carlton, January 2009 (EnergyAustralia), pp. 32–33 and Carlton, January 2009 (TransGrid), pp. 39–41.

543 Kim, D., Palia, D., and Saunders, A., *The long–run behaviour of debt and equity underwriting spreads*, Draft Paper, January 2003.

544 Kim, Palia and Saunders, January 2003, p. 5.

545 Datta, S., Iskandar–Datta, M. and Patel, A. *The pricing of initial public offers of corporate straight debt*, Journal of Finance, Vol. 52(1), March 1997, pp. 379–396.

> Nevertheless, for a very small sample of 50 firms, Datta, Datta and Patel (1997) estimate first day returns on corporate debt to be close to zero (0.15%).

This 15 basis point return is the foundation of CEG's suggestion of an allowance of 3.0 bppa for indirect costs (spread across the life of a 5–year bond). The AER notes that the Saunders et al working paper also states:[547]

> Datta, Datta and Patel (1997) show in a small sample of 50 firms that first day (short term) returns on corporate bond issues were **insignificantly different from zero**. [emphasis added]

This quote refers to analysis by Datta et al, using the standard statistical methodology to investigate the significance of a data point, which concluded that the first–day returns were equivalent to zero. Datta et al did not find empirical evidence of underpricing for debt issues.

Alternative empirical evidence presented by CEG included a paper by Cai, Helwege and Warga.[548] This paper found that offerings[549] of investment grade bonds (those rated BBB or better) demonstrate overpricing of 1 basis point—that is, the lender pays a premium, lowering the rate of interest paid by the borrower.[550] Cai et al did, however, find underpricing for high–yield, speculative grade bonds (those rated BB or lower, including unrated bonds) of 14.9 basis points. CEG argued in its first report that BBB debt, being at the 'edge of investment grade', would be more underpriced than the average investment grade debt and therefore lie somewhere between 0 and 14.9 basis points.[551]

In the draft decisions, the AER stated that there was no evidence that such a trend existed.[552] If such a trend was present, Cai et al would likely have detected it via regression analysis. However, the study did not present such analysis.

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546 CEG, May 2008 (TransGrid), p. 20, paragraph 63; CEG, May 2008 (Transend), p. 20, paragraph 64; CEG, May 2008 (Country Energy), p. 20, paragraph 63; CEG, May 2008 (EnergyAustralia), p. 15, paragraph 57 and CEG, April 2008 (Integral Energy), p. 20, paragraph 63.

547 Kim, Palia and Saunders, January 2003, p. 3, footnote 2.

548 Cai, N., Helwege, J., and Warga, A. (2007) *Underpricing in the corporate bond market,* The Review of Financial Studies I, 20(5), pp. 2021–2046.

549 The figures quoted here are for non–initial offerings of debt—that is, all debt offerings excluding the very first offering of debt by a firm. Although Cai et al also investigated (and separately report) initial offerings, CEG did not consider that these findings were relevant to the benchmark firm. The AER agrees that non–initial debt is the appropriate data point for consideration.

550 CEG, May 2008 (TransGrid), p. 20, paragraph 65. Note that the overpricing is incorrectly reported by CEG as .01 of a basis point, rather than 1 basis point. See also CEG, May 2008 (Transend), p. 20, paragraph 66; CEG, May 2008 (Country Energy), p. 20, paragraph 65; CEG, May 2008 (EnergyAustralia), p. 16, paragraph 59 and CEG, April 2008 (Integral Energy), p. 20, paragraph 65.

551 CEG, May 2008 (TransGrid), p. 20, paragraph 66; CEG, May 2008 (Transend), p. 20, paragraph 67; CEG, May 2008 (Country Energy), pp. 20–21, paragraph 66; CEG, May 2008 (EnergyAustralia), p. 16, paragraph 60 and CEG, April 2008 (Integral Energy), pp. 20–21, paragraph 66.

552 AER, *TransGrid draft decision* p. 137; AER, *Transend draft decision*, p. 190 and AER, *NSW DNSP draft decision*, p. 186.

In the CEG report submitted by the NSPs with their revised regulatory proposals, CEG responded to the draft decision on this issue by repeating two points made in the May 2008 CEG report.[553]

First, CEG cited the Livingston and Zhou (2002) finding that BBB rated private debt is issued at a higher yield (measured by the spread over Treasury bonds) than public debt.[554] The AER considers this does not provide a strong rationale for consideration of the existence of underpricing. The existence of a different yield between private and public debt neither confirms nor denies the existence of underpricing when issuing either form of debt.

Second, CEG referred to its earlier statement regarding the Cai et al paper. CEG offered that the 'common sense observation that the lower a firm's credit rating the harder it will be to market new debt issues because of the increasing uncertainty associated with the value of that debt'.[555] The AER considers that there are other equally plausible explanations consistent with the observed data that do not involve the existence of underpricing of BBB grade debt. For example, it may be that the uncertainty of debt value increases dramatically once the investment/speculative threshold is crossed, but remains constant prior to reaching this threshold. Alternatively, it may be that the higher compensation provided by the direct yield of lower rated debt offsets the increased debt marketing difficulties, such that no indirect cost is incurred. In other words, a higher yield may be sufficient to attract investors to lower grade debt.

The AER does not consider the material cited by CEG in support of this argument to be empirical evidence. The interpolation of bond underpricing between investment grade bonds and speculative grade bonds assumes a known relationship between credit ratings and issuance prices relative to the face value of the debt issued. No theoretical basis or empirical evidence has been provided by CEG to support this relationship. Accordingly, the AER maintains its position that adequate empirical evidence on BBB underpricing has not been provided by the NSPs, within their regulatory proposals, revised regulatory proposals or associated consultant reports.

Finally, the AER considers there are substantial problems with concluding that the benchmark firm issuing debt in Australia will incur underpricing costs, on the basis of an overseas study. No evidence that BBB+ debt is sold (on average) at a discount in Australia has been provided to support the NSPs' arguments on underpricing. The NSPs have argued that there are significant differences between debt raising costs in the United States and Australia, and that the debt raising costs in the United States were lower than in Australia. For example, EnergyAustralia stated:[556]

> It is more than likely that the cost of raising debt in the US is lower than the cost of raising debt in Australia because of the depth of the US financial market. This is consistent with [sic] recent paper by Bortolotti, Megginson and Smart (cited in the Carlton report) which found that the US has the lowest cost of raising equity in the world.

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553 CEG, January 2009, pp. 45–46, paragraphs 151–154 (which cite paragraphs 56 and 66 of the May 2008 (TransGrid) CEG report).

554 CEG, January 2009, p. 45, paragraph 152.

555 CEG, January 2009, pp. 45–46, paragraphs 153–154.

556 EnergyAustralia, *Revised regulatory proposal*, p. 106. A similar statement is made in TransGrid, *Revised revenue proposal*, p. 42, paragraph 141.

The AER does not consider that the Bortolotti et al paper, which deals solely with equity raising costs, is relevant to debt raising costs.[557] Further, the AER does not consider that Carlton provided any empirical evidence of debt underpricing in Australia, but instead presented anecdotal statements from market practitioners that the Australian market is illiquid and therefore a more expensive place to issue debt.[558] Carlton also stated:[559]

> Anecdotally we would consider that foreign issuers would pay a premium; the "first time issuers" premium of 6 bp per annum to 12 b.p. [sic] per annum may be a useful estimate of this premium.

The AER notes that there is no empirical support for the existence of a foreign issuer premium, or that it would be equivalent to a first–time issuer premium. Most importantly, the AER notes that the Carlton report does not present empirical evidence of underpricing on Australian debt, or empirical evidence of a relationship between Australian and US debt raising costs.

The AER has not 'assumed away' empirical evidence. Rather, the empirical evidence presented by the NSPs and their consultants does not support the claims made. The AER considers that it has not been provided with empirical evidence of debt underpricing for BBB+ rated bonds in any country, or evidence of debt underpricing in Australia.

Relationship between indirect and direct debt raising costs

The NSPs submitted that the direct and indirect debt raising costs are interdependent and cannot be considered in isolation.[560] TransGrid stated that an increase in direct debt raising costs leads to a decrease in indirect debt raising costs, and vice versa.[561] The key argument made by CEG for this substitutability is that direct debt raising costs are related to the marketing of the debt—if the debt itself becomes cheaper (via an increase in indirect cost), then it is easier to sell and marketing costs will drop.[562]

While several studies were cited by CEG for equity issues, the AER considers that no conclusive empirical evidence was presented linking direct and indirect debt raising costs for BBB+ debt.

The AER notes that when the Saunders et al working paper (which formed the basis of much of the CEG report on this issue) was accepted for publication in 2008, all

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557 Bortolotti, B., Megginson, M. and Smart, S., *The rise of accelerated seasoned equity underwritings,* Journal of Applied Corporate Finance, 2008, vol. 20(3), pp. 35–57.

558 Carlton, January 2009 (EnergyAustralia), pp. 32–33; and Carlton, January 2009 (TransGrid), p. 40.

559 Carlton, January 2009 (EnergyAustralia), p. 33; and Carlton, January 2009 (TransGrid), p. 40.

560 For example, EnergyAustralia, *Revised regulatory proposal*, p. 107.

561 TransGrid, *Revised revenue proposal*, p. 78.

562 CEG, May 2008 (TransGrid), pp. 11–12, paragraphs 26–30; CEG, May 2008 (Transend), pp. 11–12, paragraphs 27–31; CEG, May 2008 (Country Energy), p. 11–12, paragraphs 26–30; CEG, May 2008 (EnergyAustralia), pp. 8-9, paragraphs 24–27 and CEG, April 2008 (Integral Energy), pp. 11–12, paragraphs 26–30.

comments regarding underpricing had been removed.[563] The explanation offered by Saunders et al is as follows:[564]

> An analysis of the relationship between direct and indirect costs is an interesting issue. It is plausible that issuers and underwriters bargain over both the direct and indirect costs of issue, resulting in these two costs being jointly endogenously determined. However, difficulties in identifying suitable instrumental variables for IPOs, SEOs, and debt issues are significant enough that we leave tests of this relationship to future work.

This indicates that no empirical relationship had been established between these two cost categories by Saunders et al, which was the primary source of academic material cited by CEG.

In conclusion, the AER has considered the evidence presented by TransGrid and its consultants on the relationships between indirect and direct debt raising costs. The AER has not been provided with any peer–reviewed empirical evidence to support the claim that indirect and direct debt raising costs must be considered jointly. Moreover, the AER is mindful of the absence of evidence for indirect costs (as discussed above). On this basis, the AER considers there is no need to account for any interaction effects between indirect and direct debt raising costs.

E.1.1.4 AER conclusion—indirect debt raising costs

The AER has considered the evidence presented by the NSPs and their consultants on indirect debt raising costs. In conclusion, the AER considers:

- an indirect cost allowance would be inconsistent with the BBB+ credit rating specified in the NER
- there is no empirical evidence to support the claim that BBB debt is underpriced
- there is no need to account for any interaction effects between indirect and direct debt raising costs

On this basis, consistent with its draft decisions, the AER considers it inappropriate to include an allowance for indirect debt raising costs.

E.1.2 Direct debt raising costs

Regulatory precedent—the Allen Consulting Group approach

To determine direct debt raising costs for the draft decisions, the AER adopted the methodology established by the Allen Consulting Group (ACG) in its 2004 report.[565] In developing its methodology, ACG considered evidence from a wide range of sources on international debt raising costs, regulatory practice in Australia, and domestic and international bond markets.

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563 Kim, D., Palia, D., and Saunders, A., *The impact of commercial banks on underwriting spreads: Evidence from three decades*, Journal of Financial and Quantitative Analysis, December 2008, vol. 43(4), pp. 975–1000.

564 Kim, Palia and Saunders, December 2008, p. 977.

565 ACG, *Debt and equity raising transaction costs*, December 2004, pp. 27–53.

To ensure relevance to the context in consideration, ACG assessed actual debt issued by Australian utility and infrastructure companies, including domestic bonds, term loans and international bonds. ACG broke down the direct debt raising costs into gross underwriting fees, legal and road show fees, company credit rating fees, issue credit rating fees, registry fees and paying fees.[566] A recommendation was made for the costs of each of these categories, based upon available evidence including Bloomberg and Standard and Poor's. Since a proportion of these costs are fixed, the number of bonds issued in a regulatory control period has a material effect on debt raising costs. The ACG methodology determines the number of standard–size issues that are required to fund the debt portion of the opening RAB of each regulated firm, and apportions fixed and variable costs on this basis. This gives a benchmark percentage, which is applied to the debt portion of the RAB each year to determine the debt raising cost allowance.

Consistent with previous transmission determinations, the AER applied this approach to calculate the allowance for direct debt raising costs in the draft decisions.[567]

Alternative to the ACG approach

The NSPs disputed the draft decision on direct debt raising costs, and proposed allowances of 12.5 bppa in their revised regulatory proposals.[568] The NSPs, through CEG, relied on a working paper by Saunders, Palia and Kim as an alternative estimate of direct debt raising costs.[569] In the draft decision, the AER considered that this work was not relevant as it measured debt issued by non–regulated US firms. Further, the AER considered that the high variance in debt issuance costs presented in the paper suggested that use of the market–wide average debt raising cost was not appropriate.[570]

In reiterating the Saunders et al working paper as providing an appropriate estimate, TransGrid and EnergyAustralia responded to the draft decision in the following three ways:[571]

- the AER sample contained the same biases as the Saunders et al sample, including US firms and excluding regulated utilities[572]
- the use of US–based data would produce a lower estimate than Australian–based data, since the market there was more liquid[573]
- 'the private debt market has ceased to exist in the wake of the global financial crisis', and so could not be used as an estimate.[574]

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566 ACG, December 2004, p. 52.

567 AER, *TransGrid draft decision*, p. 139; AER, *Transend draft decision*, pp. 191–192; AER, *NSW DNSP draft decision*, p. 188 and AER, *ACT draft decision*, p. 106.

568 TransGrid, *Revised revenue proposal*, p. 78; Transend, *Revised revenue proposal*, p. 57 and EnergyAustralia, *Revised regulatory proposal*, p. 107.

569 Kim, Palia and Saunders, January 2003.

570 AER, *TransGrid draft decision*, p. 138.

571 CEG included a fourth argument; that the AER was inconsistent in taking one portion of a study and ignoring other portions of the same study. This issue is not relevant to the choice between Kim, Palia & Saunders and ACG, and is dealt with later in this appendix.

572 TransGrid, *Revised revenue proposal*, p. 77; EnergyAustralia, *Revised regulatory proposal*, p. 106. See also CEG, May 2009, p. 43, paragraph 142.

573 TransGrid, *Revised revenue proposal*, p. 77; EnergyAustralia, *Revised regulatory proposal*, p. 106. See also CEG, May 2009, p. 43, paragraph 141.

The AER refutes the NSPs' claims and notes:

- the ACG data is exclusively based on Australian firms operating in the utilities and infrastructure sectors.[575] It is incorrect for TransGrid to state that this is not the case, or that 'such data is not publicly available'[576]
- no empirical evidence has been presented by any NSP or consultants to support the claim that liquidity issues cause a debt premium in Australia relative to the USA. Regardless, the AER considers numerous factors in addition to liquidity must be considered
- CEG consider that the private debt market still exists, and note anecdotal evidence of a private–placed NAB debt issue 'at the time of writing'.[577]

The AER considers that the key question is which of the two methodologies best estimates the direct costs incurred by a benchmark firm issuing debt under the regulatory framework in Australia. The AER considers that if the desired target cannot be measured directly, the closest matching alternative should be selected. This is analogous to CEG's statement:[578]

> If one is attempting to estimate the cost of something it is preferable to use data on the cost of that thing rather than data on the cost of something else.

A comparison of the main characteristics of the two approaches is included in table E.1, with areas of difference from a benchmark firm shaded on the table.

Table E.1: Comparison of study characteristics with the benchmark scenario

	Firm Location	Debt Market	Firm Type	Debt Type
Benchmark firm[a]	Australian	Australian[b]	Regulated electricity network	Public
ACG (Bloomberg/ S&P)	Australian	USA[c]	Regulated utility and infrastructure	Private
Saunders, Palia & Kim (2003)	USA	USA	Excludes all regulated firms	Public

Source: Compiled from ACG (2004) and CEG (2008).
(a) For clarity, the AER restates that the benchmark efficient NSP is a pure play regulated electricity network operating in Australia without parent ownership.
(b) While the benchmark debt issue is in the Australian market (consistent with the cost of debt being based on Australian corporate bond yields); in practice, a firm may choose to establish a debt portfolio that includes foreign bonds where it believes this is more efficient, bearing the risk and rewards of this action.
(c) Although the ACG methodology estimates underwriting spread from the US market, it does include Australian estimates for other components of debt raising costs.

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574 TransGrid, *Revised revenue proposal*, p. 77.
575 The full list of companies is included at appendix A of the 2004 ACG report, and includes energy sector companies Australian Gas Light, United Energy, ETSA Utilities and SPI Australia.
576 TransGrid, *Revised revenue proposal*, p. 77.
577 CEG, January 2009, pp. 40–41, paragraphs 135–136.
578 CEG, January 2009, p. 36, paragraph 119.

The AER observes that neither measure of direct debt raising costs is a perfect match for the benchmark firm. Both the ACG methodology and the Saunders et al approach are based on US market data, not Australian market data. The ACG sample differs from the benchmark in one additional way; it measures private debt rather than public debt. However the Saunders et al sample differs from the benchmark in two additional ways; it is based on US firms (not Australian) and its sample excludes all regulated firms.

Given that the two approaches vary from the benchmark scenario in differing ways, the closest match will be that approach whose differences have the smallest combined impact. The common difference arising from measurement of US debt markets rather than Australian debt markets can be discounted as equally impacting upon both approaches.

The ACG approach uses private debt issuance costs rather than public debt issuance costs. The AER considers that this difference will exert limited (if any) systematic bias on the measurement of direct debt raising costs. It makes this inference on the basis of the Livingston and Zhou study that found no significant difference between public and private debt raising costs.[579] The AER is aware that this study was based on US firms and that it used a range of firms (based on market distribution) rather than exclusively regulated utilities. Nonetheless, the AER considers that Livingston and Zhou does not provide evidence of any difference between public and private debt issuance costs. To exclude this study from application to the benchmark firm, the NSPs would have to argue that the public/private difference exists for regulated firms but not for the market as a whole. No theoretical rationale for such a statement exists, and no empirical evidence has been presented to support such a statement. Accordingly, the AER considers that the ACG methodology provides a very close proxy to the benchmark scenario (except for the shared imperfection of measuring US market data).

The Saunders et al approach excludes all regulated firms from analysis, rather than using a sample that consists entirely of regulated utilities.[580] The AER considers that this will have a significant systematic influence on the measurement of direct debt raising costs. The AER observes that although the Saunders et al working paper finds average direct debt raising costs of 68 basis points, the fifth percentile direct costs lie at 23 basis points, while the 95th percentile lie at 353 basis points.[581] The AER considers that given this large range, it is inappropriate to take the sample average and apply it to a set of firms that do not intersect with the original sample. Saunders et al find that firm–specific characteristics account for the majority of variation (51.7 per cent) in direct costs.[582] The AER considers that this further supports the inference that regulated utilities would significantly deviate from the sample average direct debt raising costs. Finally, research papers that compare regulated firms and utilities to other firms find that their status has a significant influence on direct debt

579 Livingston, M. and Zhou, L. (2002) *The impact of rule 144A debt offerings upon bond yields and underwriter fees,* Financial Management, Winter 2002, pp. 5–27.

580 Kim, Palia and Saunders, 2003, p. 7. The AER notes that a sample consisting purely of regulated electricity networks would be the best match for the benchmark firm.

581 Kim, Palia and Saunders, 2003, p. 35, table 1.

582 Kim, Palia and Saunders, 2003, p. 40, table 6.

raising costs.[583] The AER therefore considers that exclusion of regulated firms is a significant departure from the benchmark scenario.

The Saunders et al approach also differs from the benchmark as it is based on US firms rather than Australian firms. The AER considers that although cross–country differences are numerous, the effect of firm location will be overshadowed by the effect stemming from debt market location. Since both the ACG and Saunders et al approaches issue debt in the US, the additional difference stemming from the firm being located in the US is not expected to be of great significance.

Overall, the AER considers that the appropriate benchmark should be determined according to the ACG approach, based upon the cost of Australian regulated utilities issuing private debt in the United States. The AER considers this to be closer to the benchmark scenario than the Saunders et al approach, which is based on American non–regulated firms issuing public debt in the United States.

Consideration of components from one report

CEG stated the AER was inconsistent to take one proposition from the Livingston and Zhou study—that public debt has the same issuance costs as private debt—and reject another proposition from the same study, that gross underwriter spread is between 8.8 bppa and 9.6 bppa.[584]

The AER considers that the joint acceptance of two propositions from one research paper depends upon the degree to which the two propositions are linked in that paper. Research papers may include chains of logic that develop serially across the paper, but frequently include several investigative approaches, each of which stands in isolation. There may be no relationship between the two propositions, in which case the AER considers it is appropriate for a party to accept one and reject the other on merit. Inconsistency would only occur where it is shown that the relevant propositions in the paper are dependent on each other. Even if the two propositions are part of one chain of reasoning, then it is still logically defensible to accept the earlier proposition, but reject the latter on the grounds that an error of fact, logic or relevance occurred after the first proposition (and before the second). However, it would be inconsistent to accept a later proposition that was wholly dependent upon an earlier proposition, where the earlier proposition had been rejected as incorrect.

In considering CEG's claim, the two propositions may be summarised as follows:

1. the Livingston and Zhou regression supports that the issuance costs of public debt and private debt do not differ
2. the issuance costs projected from the full Livingston and Zhou regression will be equal to issuance costs of the benchmark firm.

However, proposition one is not dependent on proposition two. Therefore the AER considers that it is entitled to use its own estimate of direct debt raising costs. The AER considers that these propositions are part of the same logic chain, flowing from

583 See Eckbo and Masulis, *Adverse selection and the rights offer paradox,* Journal of Financial Economics, 1992, vol. 32, pp. 293–332; and Livingston and Zhou, 2002, p. 25, table VIII.

584 CEG, January 2009, p. 39, paragraph 129. Note that gross underwriting spread is not the total direct costs; this point is further elaborated later in this discussion.

the same regression analysis. However, as the first proposition is made earlier in the Livingston and Zhou argument, an acceptance of this proposition by the AER does not infer that the second proposition must also be accepted. The AER considers that there is no inconsistency in rejecting the second proposition if the AER is convinced that the logic of argument breaks down after the first proposition. The two propositions are considered below.

Interpretation of the Livingston and Zhou regression

CEG stated that the Livingston and Zhou study found a gross underwriter spread of between 8.8 bppa and 9.6 bppa.[585] The underwriter spread is not the total direct debt raising cost as it does not include other relevant fixed costs or rating costs. This range is derived from a regression that investigated the relationship between gross underwriter spread (as the dependent variable) and a range of independent variables.[586]

The AER notes that the widely accepted scientific framework emphasises the need for caution when applying a regression projection to new data points that differ substantially from the data used in its derivation. For example, there will generally be a significant difference between the debt risk premium of the Livingston and Zhou sample of public firms,[587] and the debt risk premium on the public bond issued by the benchmark firm.[588] The AER notes that the full regression was conducted to observe the impact of Rule 144A placements relative to other placement methods, and that this purpose does not match the purpose for which CEG applied the regression results. In particular, the AER observes that Livingston and Zhou chose not to include the presence or absence of industry regulation as an independent variable, and that such a variable would be particularly pertinent to CEG's interpretation and projection.

The AER notes that CEG derived an upper bound for direct debt raising costs, and that CEG stated this calculation followed the generally accepted best practice of using all independent variables for a projection, regardless of statistical significance. However, the AER observes that CEG omitted two variables, 'Log of Proceeds'[589] and 'Percentage of Years of Call Protection',[590] and miscalculated another, 'Log of Issue Frequency'.[591] The inclusion and correction of these variables in the regression

585 CEG, January 2009, p. 38, paragraph 127.

586 Livingston and Zhou, 2002, p. 25, Table VIII.

587 Livingston and Zhou, 2002, p. 12, Table I. The rule 144A bonds had average debt risk premium of 351 basis points, which mitigates but does not eliminate this risk.

588 The AER notes that although debt risk premiums change over time, the benchmark firm debt risk premium is currently more than three times the Livingston and Zhou public bond average.

589 Log of proceeds is expressed in $US dollars, so the $AU 200 million benchmark bond size was converted to ln(150).

590 Call protection refers to the inability of the issuer of the bond to 'call back' (i.e. force redemption) earlier than the maturity of the bond. Since the regulated benchmark firm can predict its cash flow and gearing, it can safely issue 100 per cent call protected bonds to reduce borrowing costs.

591 The January 2009 CEG report considered only the case of Integral Energy, which would make 11 issues in 10 years (and therefore 3.3 issues in the 3 years of the study). Figures relevant for other NSPs can be derived using reasonable assumptions (60 per cent of RAB is debt, issue size of $AU 200 m, $AU/$US exchange rates of $0.72).

projection[592] would result in the range of underwriting spreads presented in table E.2.[593]

Table E.2: Corrected regression projections of gross underwriter spread for each NSPs

Issuer	TransGrid	Transend	Country Energy	Energy Australia	Integral Energy	Actew AGL
Total cost (bp)	56.1	60.9	56.1	54.0	56.7	62.2
Annual cost (bppa)[a]	7.46	8.10	7.46	7.18	7.54	8.27

Source: AER analysis, based on Livingston and Zhou (2002).
(a) Annual figures have been derived using the CEG amortisation methodology.

The gross underwriter spreads range from 54.0 to 62.2 bppa, which is between 4.8 and 13 basis points lower than the CEG–quoted best estimate of 67 bppa. If amortised over 10 years (as per the CEG methodology, using a real weighted average cost of capital (WACC) of 6.99 per cent) this equals an allowance of between 7.18 and 8.27 bppa.

The AER notes that gross underwriter spread is not the only type of direct cost. Direct costs also include legal fees, rating fees and other costs. In the latest update of the AER methodology, a gross underwriter spread of 6.0 bppa was applied to all NSPs with other costs adding between 3.2 and 2.0 bppa. While the correction of CEG errors reduces the difference, the Livingston and Zhou regression projection remains at least 1.18 bppa higher than the underwriting allowance of 6.0 bppa which was included in the draft decision.

The AER notes that marked differences in approach have resulted in a material difference between the two estimates of underwriting costs. The Livingston and Zhou regression analysis is based upon amortized 10–year debt, rather than straight division of five–year debt as per the ACG methodology.[594] The ACG methodology was based on Australian utility and infrastructure companies issuing debt that closely matches the benchmark firm. In contrast, the Livingston and Zhou estimate is impaired by the difficulties in projecting from regression analysis, as detailed above, and is based on US firms issuing debt in the US market.

Accordingly, the AER concludes that the underwriting estimate of 6.0 bppa, based on ACG's methodology, is most appropriate for determining the level of direct debt raising costs that would be incurred by the benchmark efficient entity. Other direct debt raising costs must be added to this gross underwriting spread such as legal and roadshow, company credit rating, issue credit rating, registry and paying fees. The

592 The AER notes that seven other significant variables, including six rating variables and the *First Time Debt Dummy*, would have no impact on the projection and were also omitted from the CEG table.

593 The regression is dependent on the number of debt issues made by the firm; since this varies across NSPs, a range of gross underwriter spreads results.

594 Separate consideration of the amortization/straight division issue is provided later in this appendix.

AER notes that no estimate of these figures is made by CEG (or Saunders et al), and that therefore the ACG methodology remains the only viable approach for estimating these costs.

E.1.2.1 AER conclusion—direct debt raising costs

The AER notes the view of Associate Professor Handley, who concluded that an appropriate range for total direct debt raising costs was between 8 and 12 basis points per annum.[595] The AER views the upper end of this range, derived from Saunders et al (~12 basis points) and the Livingston and Zhou full regression (~10 basis points) as being unreliable, for the reasons detailed earlier in this appendix.

In conclusion, the AER considers that:

- the exclusion of regulated firms from the Saunders, Palia and Kim working paper makes it an inferior estimate of direct debt raising costs when compared to the ACG methodology
- the problems associated with applying a regression projection and the incorrect firm location makes the full Livingston and Zhou regression projection an inferior estimate of direct debt raising costs when compared to the ACG methodology
- an individual component of the Livingston and Zhou paper (namely the equivalence of public and private debt raising costs) can be accepted separately to the full Livingston and Zhou regression projection.

On this basis, consistent with its draft decisions, the AER concludes that the ACG methodology is the most reliable and accurate method for setting direct debt raising costs, and that it will be applied for all NSPs.

E.1.3 Other issues

Current market conditions

CEG argued that the cost of issuing debt is likely to be at historically high levels and that an estimate from the top end of any historical range is appropriate.[596] CEG base this claim on the rapid change in the global economy in the past year.

The AER notes that this issue was not addressed in the draft decisions, as the likely impact of the global financial crisis was not yet evident. The AER notes the change in the economic outlook for the Australian economy since mid–2008 has been reflected in official forecasts by Treasury.[597] The rapid change in the economic outlook is closely linked to the global financial crisis which manifested itself in the second half of 2008. The global financial crisis has been portrayed as being the most serious economic event affecting developed economies since the great depression of the 1930s.[598]

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595 Handley, April 2009, p. 30.

596 CEG, January 2009, p. 42, paragraph 140. Note that the effects of current market conditions on the cost of debt (in contrast to the cost of issuing debt) are considered in detail in section 5 of this final decision.

597 The Treasury, *Updated economic and fiscal outlook*, February 2009. Available: http://www.budget.gov.au/2008-09/content/uefo/html/index.htm.

598 IMF, *World economic outlook*, October 2008.

Given this extraordinary change in circumstances within the economic environment, the AER has decided to consider the updated information relating to debt raising costs in making its final decision.

Pursuant to the ACG methodology, the AER sets debt raising costs on the basis of a long–term benchmarking approach. The benchmark debt raising costs applied in the draft decision reflect a 2008 update of the ACG 2004 findings on debt raising costs. The standard debt issuance costs are set based on a benchmarked sample of debt issues over the time period 2000–2008.

While there will always be volatility in debt markets and variation in the cost of raising debt, the AER approach, consistent with the NER framework, takes a long–term view of debt raising costs. The AER's update, based on benchmarked data over 2000 to 2008, found that the appropriate gross underwriting fee for issuing debt remains at 6.0 bppa. The 2008 update included three additional bond issues by BHP on 26 March 2007 as set out in table N.3. The average underwriting fees on these bonds were consistent with the 2006 update benchmark.

Table E.3: BHP Billiton international bond issues, 26 March 2007.

Issuer	Years to maturity	Issue size ($millions)	Total gross underwriting fees
BHP Billiton	2	$1080.4	0.10% or 5.0 bppa
BHP Billiton	5	$771.7	0.35% or 7.0 bppa
BHP Billiton	10	$926.0	0.45% or 4.5 bppa

Source: AER analysis, based on data from Bloomberg.

The only evidence put forward by CEG that an estimate from the top end of the historical range is appropriate was the bond issue from National Australia Bank (NAB) in the US private placement market. CEG argued that NAB's issue costs of 7.6 bppa indicates the AER's estimate of 6 bppa is too low.

The AER notes that the NAB issue was for a tenor of 3 years while the benchmark estimate by the AER used a tenor of 5 years.[599] Further, the underwriting cost observed for one bank debt issue is not, in isolation, an appropriate benchmark for setting debt raising costs.

The AER does not consider the evidence in relation to one bond issue is sufficient to justify choosing a figure from the top end of historical range and depart from the AER's methodology of a long–term benchmarking approach to setting debt raising costs.

599 The AER notes that, as a number of costs are likely to be one–off fixed costs, going from three to five years maturity will reduce the basis points per year cost.

Amortisation of debt raising costs

In its report, CEG argued that the current debt issuance methodology used by the AER is biased as it fails to take into consideration the time value of money.[600]

The AER's methodology involves dividing total issuance costs by the debt maturity to obtain an annual allowance, rather than equating the net present value of the yearly payments with the total debt issuance cost using an appropriate discount rate.

The AER notes that this issue was not raised by the NSPs in their regulatory proposals, but was raised for the first time in their revised regulatory proposals. This issue was not raised in response to a matter addressed in the draft decision. As such the AER considers it need not review the variation to the methodology as requested by the NSPs.[601] Notwithstanding this aspect, the AER has undertaken a review of the NSPs' proposed variation to the methodology.

The AER acknowledges that an adjustment for time value of money is generally appropriate when upfront costs are repaid over time. In this instance, following the ACG methodology, no such adjustment is made. However, the key outcome is that the AER's conservative approach does not under compensate the NSPs.[602] The modelling employed by the AER to estimate debt issuance costs assumes that five year maturity bonds are issued. The ACG methodology simply divides the total debt issuance cost of a five year bond by five, to derive an annual allowance.

However, the NER requires that the benchmark bond is of a ten year term.[603] Therefore, if amortization were to be undertaken in accordance with the term of the bond specified in the NER, it would be based on a ten year horizon, involving the change of bond term from five years to ten years. Given that a proportion of debt issuance costs are made up of fixed costs, the debt issuance costs for a ten year bond will not be significantly larger than the debt issuance costs of a five year bond. The amortized cost of ten year debt issuance costs would provide a lower allowance than the simple division of five year debt issuance costs.[604] The AER considers that the current ACG methodology is therefore a conservative approach, in that the NSPs are no worse off (and in fact are likely to be slightly better off) than under an amortisation approach.

On this matter, Associate Professor Handley considered that the differences between amortisation and simple division are not sufficient to warrant consideration.[605]

The AER has assessed the evidence presented by the NSPs on amortization costs. On the basis of this assessment, the AER considers there is no requirement to amend the methodology applied in the draft decision, for the following reasons:

- a new methodology cannot be presented in a revised regulatory proposal unless it is addressing a matter raised in the draft decision

600 CEG, January 2009, pp. 47–48, paragraphs 157–166.
601 For TNSPs, see clauses 6A.14.3(h) and 6A.14.3(c)(3)(ii) of the NER. For DNSPs, see clause 6.10.3(b) of the transitional chapter 6 rules.
602 ACG, 2004, pp. xvi–xix.
603 NER, clause 6A.6.2.
604 AER analysis.
605 Handley, April 2009, pp. 29–30.

▪ amortisation would have to occur over ten years, not five, so the allowance would be unlikely to increase (and may even decrease).

Overall, the AER is satisfied that its methodology ensures that the NSPs will have the opportunity to recover at least the efficient costs, as is required by the NER.[606]

Inflation of debt issuance costs

CEG argued that the non–underwriting transaction costs in debt issues should be indexed for inflation.[607] The AER notes that this issue was not raised in the NSPs' regulatory proposals, but raised for the first time in their revised regulatory proposals. This issue was not raised in response to a matter addressed in the draft decision. As such the AER considers it need not review the variation to the methodology as requested by the NSPs. Notwithstanding this aspect, the AER has undertaken a review of the NSPs proposed variation to the methodology.[608]

The AER considers that the argument for inflation indexing raised by CEG is not theoretically sound. Given that issuance costs are expressed as a percentage (total debt issuance costs divided by debt size), it is inconsistent to focus on the changes in the numerator without considering the effects on the denominator. The AER considers that while the fixed costs may increase by inflation, the size of the debt issue will also increase by inflation.

The AER considers that this problem is illustrated by consideration of an extreme case. If inflation was to be applied only to fixed costs and not to the amount of debt issued, then at some future point the percentage cost of issuing debt would surpass 100 per cent. The AER considers that this is not a plausible outcome, as the amount of debt issued would not be enough to cover the costs associated with the debt issue. In this case, the debt market would not exist.

The AER notes the view of Associate Professor Handley, who advocated that the effect of any proposed inflation indexation is below a reasonable threshold of materiality.[609]

The AER has considered the argument presented by the NSPs for an allowance for indexation. On the basis of this assessment, the AER considers there is no requirement to index debt issuance costs, for the following reasons:

▪ a new methodology cannot be presented in a revised regulatory proposal unless it is addressing a matter raised in the draft decision
▪ the indexation of debt issuance costs without also adjusting for changes to bond issue size is likely to result in implausible outcomes in the long–term.

606 For TNSPs, see clauses 6A.14.3(h) and 6A.14.3(c)(3)(ii) of the NER. For DNSPs, see clause 6.10.3(b) of the transitional chapter 6 rules.

607 CEG, January 2009, p. 49, paragraphs 167–169.

608 For TNSPs, see clauses 6A.14.3(h) and 6A.14.3(c)(3)(ii) of the NER. For DNSPs, see clause 6.10.3(b) of the transitional chapter 6 rules.

609 Handley, April 2009, pp. 29–30

E.1.4 Summary of debt raising cost considerations

The AER has considered the arguments made by the NSPs on debt raising costs, including consultant reports and all relevant submissions.

The AER considers that there is no basis for an allowance for the indirect costs of debt raising. The AER has found no reliable empirical evidence of the existence of underpricing. If indirect costs do in fact occur in practice, the current methodology of providing an allowance for the cost of debt would detect and include compensation as part of the debt yield. Therefore, separate compensation would result in double counting and be inconsistent with the regulatory framework.

The AER considers that the ACG methodology represents the best estimate of the direct costs of debt raising. This is determined by the close proximity of the ACG approach to the benchmark scenario; issuance of BBB+ rated public debt by the benchmark firm in Australian debt markets. The AER considers that none of the proposed alternative methodologies are appropriate, principally because of their failure to consider the characteristics of debt issued by regulated utilities.

The AER considers that there is no reason to deviate from the established approach as a result of transient market conditions. Finally, the AER finds no evidence of material under–compensation for the benchmark firm sufficient to warrant methodological change to accommodate amortisation and inflation.

For the NSPs, the AER has maintained the application of the established ACG methodology to determine the appropriate benchmark allowance for direct debt raising costs in this final decision. This allowance will be dependent upon the number of standard sized debt issues required by each NSP. The allowance, expressed in bppa, will then be applied to the debt portion of each NSP's RAB for each year of the next regulatory control period to determine the benchmark debt raising costs included in the opex forecast.

E.2 Equity raising costs

E.2.1 Rationale for joint consideration

Similar to the approach for debt raising costs, the NSPs have adopted a joint position in relation to proposed equity raising costs. In their revised regulatory proposals, the NSPs have essentially[610] applied the same parameters for equity raising costs:

- a base unit rate for equity raising costs of 7.6 per cent of the external equity required each year[611]
- an allowance for use of retained earnings of 3.8 per cent of retained earnings between normal dividend yield and minimum dividend yield[612]

[610] TransGrid stated that retained earnings were not costless and included an allowance in its equity raising calculations, but unlike the other NSPs it did not include the retained earnings allowance in its revised total opex allowance.

[611] TransGrid, *Revised revenue proposal*, p. 82; Transend, *Revised revenue proposal*, p. 60; Country Energy, *Revised regulatory proposal*, p. 46; EnergyAustralia, *Revised regulatory proposal*, p. 49; Integral Energy, *Revised regulatory proposal*, p. 47 and ActewAGL, *Revised regulatory proposal*, p. 33

- revision of the AER's cash flow analysis to incorporate the repayment of debt principal and distribution of all imputation credits.[613]

It should be noted that although the theoretical arguments on setting the dividend level were identical across the NSPs, the practical implementation differed:

- Transend implemented a 5.5 per cent dividend yield[614]
- TransGrid and EnergyAustralia implemented a 70 per cent dividend payout ratio[615]
- Integral Energy implemented the 70 per cent dividend payout ratio, but proposed an additional system for tracking imputation credits and compensating the firm.[616]

As with debt raising costs, the shared position of the NSPs is reinforced by reliance on the same consultant reports. In the NSPs' regulatory proposals variants of the CEG report were submitted.[617] In their revised regulatory proposals, a report by CEG is referenced and submitted by the NSPs—all submitted versions are the same apart from the titles.[618] TransGrid and EnergyAustralia also submitted a report by Tony Carlton, although there are some variations between the two versions.[619] EnergyAustralia submitted a report by Professor Bruce Grundy.[620] Further, EnergyAustralia's submission requested that all reports and supporting documents which it had submitted as part of its regulatory proposal and revised regulatory proposal be considered by the AER in making its final determination for all the NSPs.[621]

Integral Energy submitted a report by KPMG[622] and comments on cash flow modelling.[623] TransGrid submitted an additional memorandum by CEG,[624] as well as

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612 TransGrid, *Revised revenue proposal*, p. 81; EnergyAustralia, *Revised regulatory proposal*, pp. 48–49; Integral Energy, *Revised regulatory proposal*, p. 45–46. Transend, Country Energy and ActewAGL did not explicitly adopt this position, but referenced support for the January 2009 CEG report.

613 TransGrid, *Revised revenue proposal*, pp. 80–81; Transend, *Revised revenue proposal*, p. 60; EnergyAustralia, *Revised regulatory proposal*, pp. 47–48; Integral Energy, *Revised regulatory proposal*, pp. 46–47. Country Energy and ActewAGL did not explicitly adopt this position, but referenced support for the January 2009 CEG report.

614 Transend, *Revised revenue proposal*, p. 60.

615 TransGrid, *Revised revenue proposal*, p. 81; and EnergyAustralia, *Revised regulatory proposal*, pp. 48–49

616 Integral Energy, *Submission to the Australian Energy Regulator 2009 to 2014*, 16 February 2009, p. 10; see also Attachment 3.

617 CEG, May 2008 (TransGrid); CEG, May 2008 (Transend); CEG, May 2008 (Country Energy), CEG, May 2008 (EnergyAustralia); CEG, April 2008 (Integral Energy).

618 CEG, January 2009. Cited by TransGrid, *Revised revenue proposal*, p. 77; Transend, *Revised revenue proposal*, p. 56; Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Revised regulatory proposal*, p. 105; Integral Energy, *Revised regulatory proposal*, p. 43; and ActewAGL, *Revised regulatory proposal*, p. 33.

619 Carlton, January 2009 (EnergyAustralia); Carlton, January 2009 (TransGrid).

620 Grundy, B. D., *A note on the costs of equity financing*, 13 January 2009.

621 EnergyAustralia, *Submission*, 16 February 2009.

622 KPMG, *Review of certain assumptions in the AER's financial model to support the draft NSW distribution network revenue 2009–2014*, report to Integral Energy, January 2009.

623 Integral Energy, *Submission*, 16 February 2009.

624 CEG, *Memorandum on the Ofgem treatment of equity raising costs*, 18 February 2009.

a report by SFG.[625] The JIA submitted a report by CEG that merges parts of the May 2008 and January 2009 CEG reports with new analysis.[626]

The AER notes that issues relating to the equity raising costs on the initial opening regulatory asset base are specific to Transend and do not relate to the argument for benchmark equity raising costs associated with forecast capex. Accordingly, any submissions or arguments solely related to this issue are not dealt with in this appendix. All references to 'equity raising costs' in this appendix refer to equity raising costs associated with forecast capex.

Due to the consistency between the opex provisions of the NER under which the equity raising cost proposals are assessed, the NSPs' revised regulatory proposals and the supporting consultancy reports, the AER jointly assessed equity raising costs of the NSPs. The AER's analysis and conclusions are contained in this appendix, which is reproduced in each of the AER's final decisions for the NSPs.

The AER considers that it is important for a consistent methodology to determine the appropriate allowance for benchmark equity raising costs to be applied in its final decisions for the NSPs.

E2.2 Regulatory framework for equity raising cost allowance

The CAPM encapsulates the return required by the providers of equity capital given the inherent risk in each asset. The WACC determines a total rate of return given mandated assumptions about the gearing of the benchmark firm and the cost of debt capital. This regulatory framework requires the AER to calculate the total return required by investors in aggregate, and includes consideration of company tax, (including the effect of imputation credits). The regulatory framework does not encapsulate personal transaction costs, including the final income tax paid by personal investors, or the rate of return given to any individual capital provider (as opposed to investors in aggregate). Associate Professor Handley noted that to be consistent with this framework, all cash flows need to be expressed on a similar basis:[627]

> In other words, cash flows should be after company tax, before personal tax, after underpricing costs but before other personal (transactions) costs.

The regulatory allowance for equity raising costs should compensate the benchmark firm for the transaction costs incurred as a result of required equity capital raising (referred to as equity raising costs). Such transaction costs may be appropriately considered as part of an NSP's opex forecasts (while rate of return issues cannot be considered under the opex provisions of the NER). As an opex item, the proposed equity raising cost allowance is subject to the NER requirement that forecast opex reasonably reflects the costs that a prudent operator in the circumstances of the relevant NSP would require to achieve the opex objectives.[628] This is in contrast to an allowance for the return on capital, which is separately described in clause 6A.6.2 of

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625 SFG, March 2009.

626 CEG, November 2008.

627 Handley, April 2009, p. 10.

628 For DNSPs, see clause 6.5.6(c)(2) of the transitional chapter 6 rules. For TNSPs, see clause 6A.6.6(c)(2) of the NER.

the NER for TNSPs and clause 6.5.2 of the transitional chapter 6 rules for the ACT/NSW DNSPs for the next regulatory control period .[629]

The AER considers that it is essential to correctly characterise the components of the equity raising allowance, to ensure elements more correctly attributable to the rate of return are not included as transaction costs.

Deviations from the benchmark firm

The AER notes that many of the NSPs are government owned. The AER considers that this deviation from the benchmark structure is likely to result in windfall gains to the government owned NSPs, as they do not issue shares and therefore do not incur equity raising costs to the extent that the benchmark efficient NSP does.[630] Additionally, the obtained value of imputation credits (gamma) for these government owned NSPs will effectively be zero (rather than 0.5), since the government receives both taxes—paid under the National Tax Equivalence Regime (NTER)—and dividends as the shareholder. In this instance, imputation credits are of no additional value to the shareholder as any gains are offset by a reduction in taxes received. Despite these deviations from the benchmark firm, the AER considers that it is appropriate to assess the NSPs in accordance with the notional benchmark firm, that is, as a pure play regulated electricity network operating in Australia without parent ownership. This is consistent with competitive neutrality principles for the treatment of government owned firms.

E.2.3 Indirect costs of equity raising

The NSPs' revised regulatory proposals disputed the draft decision on indirect equity raising costs, also known as underpricing. The NSPs proposed a total equity raising allowance of 7.6 per cent, including both direct and indirect components.[631] TransGrid stated that indirect and direct costs cannot be considered in isolation, but must be jointly determined and measured. The NSPs' revised regulatory proposals generally provided a summary statement in justification of an allowance for indirect costs, referring to consultant reports for evidence.[632]

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629 The AER notes that it is undertaking a review of WACC concurrent with its review of TransGrid's and Transend's revenue proposals. The WACC review involves the consideration of parameter inputs into the CAPM and WACC. The AER further notes that for the purposes of the AER's ACT/NSW distribution determinations for the next regulatory control period, the rate of return parameters were set within transitional provisions of the NER.

630 The AER notes that the NSW State Owned Corporations (TransGrid, Country Energy, EnergyAustralia and Integral Energy) have only issued two shares each, one of each pair held by the NSW Treasurer and the other by the NSW Minister for Finance; see State Owned Corporations Act 1989, Part 3, Division 2, Section 20H. Transend has four shares, all held by the Crown in Right of the State of Tasmania; see Transend, *Annual report 2007–08*, p. 41. ActewAGL is a 50/50 partnership between Actew Corporation (a wholly owned ACT government corporation with two shares— held by the ACT Chief Minister and Deputy Chief Minister) and Jemena Networks (ACT), a privately owned company; see ActewAGL, *Annual and sustainability report*, 2008, p. 4.

631 TransGrid, *Revised revenue proposal*, p. 82; Transend, *Revised revenue proposal*, p. 60; Country Energy, *Revised regulatory proposal*, p. 46; EnergyAustralia, *Revised regulatory proposal*, p. 49; Integral Energy, *Revised regulatory proposal*, p. 47; and ActewAGL, *Revised regulatory proposal*, p. 33.

632 For example, TransGrid, *Revised revenue proposal*, pp. 80–81; EnergyAustralia, *Revised regulatory proposal*, p. 43.

Personal transaction costs

CEG stated that, when equity raising via rights issue occurs, existing shareholders that allow their rights to lapse have their investments diluted. CEG inferred that shareholders may prefer to avoid this dilution by either selling their rights (if renounceable) or taking up the rights before immediately selling the new share (if non–renounceable). CEG noted that either action incurs transaction costs, with the latter action possibly resulting in realisation of capital gains. CEG argued that these transactions costs reflect the indirect cost of a rights issue.[633]

The AER considers that separate compensation for investor level transaction costs, including investor level taxes is inconsistent with the regulatory framework. The regulatory framework specifies that investor returns are post company tax and pre–investor tax.[634] This is consistent with conventional financial theory.

Officer and Hathaway state:[635]

> …the CAPM is typically used in the context of post–company tax but pre–personal tax returns because that is the tax band in which the vast majority of capital market transactions take place.

Finance textbook, Business Finance, states:[636]

> Conventionally, the cost of equity, k_e, is defined and measured on an after–company tax, but before personal tax, basis.

Similarly, transaction costs involved with buying and selling shares are outside the regulatory framework. The market risk premium is estimated on a market portfolio that is exclusive of the transaction costs involved in maintaining that portfolio. This was the point made by Associate Professor Handley when he stated:

> The regulatory framework requires the determination of allowed revenues to the regulated firm to be undertaken on an after company but before personal tax basis. In the current context, this is more fully described as a requirement to be undertaken on an after company tax, before personal tax, after underpricing costs but before other personal (transactions) costs basis.[637]

The AER considers that the regulatory framework does not allow for consideration of investor personal tax rates, either as income tax or capital gains tax. Under the regulatory framework, investors are assumed to be indifferent between dividends and capital gains.[638] Accordingly, the possible realisation of a capital gain does not require any allowance or offsetting adjustment.

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633 CEG, January 2009, pp. 14–15, paragraph 37–43.

634 The AER notes that this is why imputation credits are deducted from the regulatory building blocks when determining total allowed revenue for the business; to the extent that they will be redeemed, they are not company taxes but pre–payment of personal taxes.

635 Officer, R. and Hathaway, N. J., *Issues in cost of capital for QCA: Report by Capital Research Pty Ltd for Prime Infrastructure submission to the QCA*, March 2004, p. 2.

636 Peirson, G., Brown, R., Easton, S. and Howard, P., *Business Finance: 8th Edition*, McGraw–Hill, 2003, p. 449.

637 Handley, April 2009, p. 10.

638 The Sharpe CAPM assumes indifference between dividends and capital gains because there are no personal income taxes. Additionally, the estimated market risk premium is based on a cumulative return of both dividends and capital gains. This is not to say that dividends are

The AER has considered the impact of transaction costs (i.e. brokerage, search costs, bank fees) under the regulatory framework. The AER notes that a transaction occurs when the renounceable right[639] is sold, and that two transactions occur when the non–renounceable right[640] is taken up and a new share sold. However, the AER considers it inappropriate to determine that such transactions are 'extra' or 'forced' transactions—that would accordingly require compensation—without considering the pattern of transaction costs that an investor in the market ordinarily incurs.

CEG considered the case of a benchmark investor with a desired portfolio of investments. If taking up a rights issue shifts this benchmark investor away from its desired portfolio, the investor immediately takes action to restore its optimal mix of assets. The AER notes that, in the extreme case, this investor would need to continually rebalance its investment portfolio in response to any non–systematic price movement of any of its shares. The AER considers that in this case, the constant adjustment of the investor's portfolio would make the cost of one or two additional transactions immaterial. In general, the AER considers it is reasonable to assume that the investor would tolerate some changes within its ideal portfolio, and only rebalance when the changes breach certain boundaries. It may be that in some cases, a rights issue (renounceable or non–renounceable) may not have a sufficiently large effect to cause rebalancing, and all transaction costs would be avoided.

A complete answer can only be determined by a long–term comparison of the transactions required when investing in the benchmark firm with the transactions required from an alternative portfolio of investments. Crucially, there are many other aspects of a benchmark firm that reduce the total number of transactions this investor incurs. The benchmark firm pays dividends regularly, unlike capital–growth–only shares, where the investor must sell (and incur transaction costs) each time they wish to access the return on their capital. The benchmark firm has regulated, transparent cash flows, leading to a stable share value, unlike speculative shares which may require portfolio balancing on the basis of price volatility more often.

The AER considers that to demonstrate the need for an allowance on this issue, empirical evidence is required that shows the transaction costs incurred by providing equity to the benchmark firm exceed those incurred by the market on average. Such evidence would demonstrate that regulated firms incur higher equity raising costs than the market on average, for which the market risk premium is estimated. No such evidence has been provided.

The AER considers that an allowance for individual transaction costs is inconsistent with the compensation of opex under the NER. Efficiently incurred expenses are defined as those incurred by the regulated firm—and it would be economically incorrect to make an allowance for all of these costs as all investors incur investor level taxes and transaction costs.

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entirely irrelevant (see the discussion on valuation of imputation credits later in the appendix) but that the realisation of capital gain cannot be presumed to be a cost to the investor.

639 A renounceable right is one where the existing shareholder can sell their right to purchase additional shares to another investor.

640 A non–renounceable right is one where the existing shareholder must either purchase the additional shares themselves or let the right lapse. The right cannot be sold to another investor.

The equity raising cost allowance for the NSPs is designed to allow them to recover company transaction costs. The AER considers the NSPs' argument that investor level transaction costs or taxes are incurred by investors due to the use of rights issues or dividend reinvestment programs is not relevant in this context.[641] The NER implies a pre–investor level (post–company tax) CAPM and post–company tax (pre–investor tax) revenue model.[642] This was the point made by Associate Professor Handley when he stated:

> Accordingly, in the current context, observed returns based on dividends, capital gains and (the value of) imputation credits are more fully described as being expressed on an after company tax, before personal tax, after underpricing costs, but before other personal (transactions) costs basis.[643]

Accordingly, the NSPs' argument concerning costs at the investor level is inconsistent with the regulatory framework.

Overall, the AER considers that ad hoc adjustments to the post–company tax and transaction cost CAPM for investor level costs are inappropriate for the following reasons:

- such changes are inconsistent with the NER and with the CAPM as defined in the NER
- the modification of the CAPM for investor level transaction costs has not been shown to be theoretically valid
- such modification could reasonably be expected to lead to systematic over–compensation and monopoly pricing.

The AER notes that it is possible to compare investor–level transaction costs and taxes incurred by investors in Australian NSPs with the average costs incurred by other investors in the Australian market in determining an allowance for equity raising costs. However, the AER notes that implementation of any associated adjustments to allowances would not be consistent with the current rate of return methodology prescribed under the NER, which is based on corporate transaction costs not individual transaction costs.

Wealth transfer effects

CEG and Carlton stated that one aspect of indirect costs is the transfer of wealth from original shareholders to new shareholders.[644] CEG further elaborated on the mechanics of wealth transfer, and provided a detailed appendix on the cost of a rights issue.[645] Carlton provided similar analysis that demonstrated wealth transfer effects with a placement, and stated that for any seasoned equity offer (SEO) if the shares are

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641 For example, see TransGrid, *Revised revenue proposal*, p. 80; EnergyAustralia, *Revised regulatory proposal*, pp. 44–45.

642 NER, Clause 6.5.3.

643 Handley, April 2009, p. 10.

644 CEG, January 2009, pp. 14–15, paragraphs 37–43 and Carlton, January 2009 (EnergyAustralia), p. 9.

645 CEG, January 2009, pp. 50–52, Appendix A: Costs of a rights issue.

sold at a discount, then the value of the shares of the original shareholders is diluted.[646]

Associate Professor Handley observed that:[647]

> Importantly, the set of investors who take up the new shares may include one or more existing shareholders of the firm, one or more new shareholders to the firm, or a combination of both existing and new shareholders.

The AER observes that in a fully subscribed rights issue (as is likely with the heavily discounted rights issue described in the draft decision), there would be minimal wealth transfer, as existing shareholders would be expected to take up the issue and hence there would not be any new shareholders. Associate Professor Handley observed that CEG and Carlton assume that no existing shareholders participate in their benchmark firm placements and stated this was an unrealistic assumption.[648] The AER concurs with Associate Professor Handley's view. The AER considers that it is more plausible to infer that placements are regularly taken up by a mix of old and new shareholders.

The AER considers that under such a scenario, two sources of overcompensation would likely result. Original shareholders who bought new shares would be overcompensated, since the dilution effect would already be offset by the new shares they purchased, and they would also receive the benefit of the proposed underpricing allowance. Additionally, outside investors who took up new shares would also be overcompensated, since they experience no dilution effect (they had no shares to begin with) but still share in the underpricing allowance (paid to the firm as a whole). Associate Professor summarised this scenario as follows:[649]

> Importantly, this reflects the fact that underpricing costs are not borne by the firm but rather represents a transfer of wealth from one group of investors to another.

On this basis, the AER does not consider that an indirect cost allowance is an appropriate mechanism to address purported wealth transfer effects. Further, the AER considers that the regulatory framework requires consideration of returns at the company level rather than the individual level. To address wealth transfer effects would require the AER to assess returns to individual shareholders which is inconsistent with the regulatory framework.

Rights issues

The indirect costs of a rights issue

TransGrid stated 'there is no basis for assuming that a rights issue will eliminate the indirect costs of raising equity'.[650] Similar statements were made by

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646 Carlton, January 2009 (EnergyAustralia), p. 39.
647 Handley, April 2009, p. 6.
648 Handley, April 2009, p. 8.
649 Handley, April 2009, p. 8.
650 TransGrid, *Revised revenue proposal*, p. 80.

EnergyAustralia.[651] The NSPs also cited evidence from CEG, Carlton and Professor Grundy.

CEG's key argument was that a rights issue shifts costs from the benchmark firm to the individual shareholders, forcing investors to take on an underwriting role. CEG stated:[652]

> …it would be wrong as a matter of logic and economic theory to argue that by forcing existing shareholders to take on the functions of an underwriter the associated costs can be ignored.

Professor Grundy supported CEG's argument and stated that evidence of the existence of indirect costs with rights issued could be seen in the 'rights offer paradox'.[653] He cited a paper by Hansen, [654] which found that the transaction (indirect) costs of rights issues raise the total cost of rights issues above that of placements. Professor Grundy stated that this supports the observation of the relative paucity of rights issues in the marketplace (the 'rights offer paradox').

Carlton also agreed with CEG, and using data from Eckbo, Masulis and Nori, documented the forms that indirect costs will take in a rights issue—including: tax effects; liquidity impact and transactions costs; risk of failure; arbitrage activity and short selling; and anti–dilution clauses to convertible security holders.[655]

The AER considers that each of these arguments is a sub–class of the general transaction cost and wealth transfer arguments that were analysed earlier in this appendix. The AER notes that although these factors may have some predictive ability when explaining the rights offer paradox, none of the perceived indirect costs form an appropriate basis for an equity raising cost allowance. This is the logic followed by Associate Professor Handley when he stated:[656]

> In my view, none of the above suggested indirect costs of a rights issue would warrant compensation.

The use of rights issues over placements

In the draft decision, the AER stated that a discounted rights issue should be the benchmark SEO method for determining equity raising costs.[657]

The NSPs contended that private placements were used more heavily than rights issues, and are therefore a more appropriate benchmark.[658] CEG Carlton and

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651 EnergyAustralia, *Revised regulatory proposal*, p. 45.

652 CEG, January 2009, p. 16, paragraph 45–46.

653 Grundy, January 2009, p. 6, paragraphs 17–19.

654 Hansen, R. *The demise of the rights issue,* The Review of Financial Studies, 1989, vol. 1(3), pp. 289–309.

655 Carlton, January 2009 (EnergyAustralia), pp. 8–9, section 1.1.3; and Carlton, January 2009 (TransGrid), pp. 19–20, section 2.1.3. Carlton notes that he did not independently verify the Eckbo, Masulis and Nori paper - see p. 4, footnote 4 (EnergyAustralia version).

656 Handley, April 2009, p. 21.

657 AER, *TransGrid draft decision*, p. 141; AER, *Transend draft decision*, p. 194; and AER, *NSW DNSP draft decision*, p. 191.

658 TransGrid, *Revised revenue proposal*, January 2009, p. 80.; EnergyAustralia, *Revised regulatory proposal*, January 2009, p. 44; CEG, January 2009, pp. 15–16, paragraph 44; Carlton, January 2009 (EnergyAustralia), pp. 2–7; and Grundy, January 2009, p. 7, paragraph 25.

Professor Grundy all argued that if profit–maximising firms choose placements as the most common means of equity raising, placements must therefore be the most efficient method of equity raising. Accordingly placement costs are the most efficient costs available from all SEO methods.[659] The NSPs' consultants stated that the AER should base the equity raising cost allowance on an estimate of the cost of a placement, including direct and indirect cost components.

The AER considers that, even if there was conclusive evidence that a particular method of equity raising was adopted by the majority of the market, this would not necessarily require the benchmark firm to adopt this method. In particular, since the characteristics of the benchmark firm differ markedly from the market average, it is not necessary to automatically accept the average market method as appropriate. To accept the average methodology, the AER considers that empirical evidence regarding the equity choices of efficient firms similar to the benchmark firm would be necessary. The NSPs did not provide evidence regarding the propensity for a regulated Australian electricity network to use placements.

The AER notes that the conclusion that placements are more common than rights issues arises from an inappropriately narrow definition of rights issues by CEG, Carlton and Professor Grundy.[660] A rights issue is offered to existing shareholders in order to raise equity at a discount without diluting aggregate shareholder wealth. Any dividend reinvestment plan (DRP) is therefore effectively a periodic rights issue. This point was explicitly raised by Carlton, who stated in his report 'it is important to observe that a DRP is effectively a non–renounceable rights issue.'[661] Associate Professor Handley also noted the essential equivalence of rights issues and DRPs.[662]

Comparison of all 'rights based' equity methods—considered as the sum of rights issues and DRPs—with private placements, reveals that, for Australian companies, placements are not preferred to offers made to existing shareholders. This is evident in table E.4, which is derived from data cited by both CEG and Carlton:

Table E.4: Total equity raised from 1991–2000 by method

	Rights issues	Reinvested dividends	Total rights based equity	Placements	Other methods[a]	Total
Total 1991–2000 ($m, 2000)	26.3	28.9	55.2	36.8	17.4	109.4
Percent of total (%)	24.0	26.4	50.4	33.6	16.0	100

Source: Based on Brown and Chan (2004), based on ASX Fact Book 2001.
(a) Other methods includes options, calls, staff plans.

659 CEG, January 2009, p. 17, paragraph 47; Carlton, January 2009 (EnergyAustralia), pp. 17–18, section 2.1; and Grundy, January 2009, p. 9, paragraphs 31–32.
660 CEG, January 2009, p. 15–16, paragraph 44; Carlton, January 2009 (EnergyAustralia), pp. 2–7; and Grundy, January 2009, p. 7, paragraph 25.
661 Carlton, January 2009 (EnergyAustralia), p. 29; Carlton, January 2009 (TransGrid), p. 36.
662 Handley, April 2009, p. 22.

Table E.4 demonstrates that rights based equity raising is used in an absolute majority of cases (50.4 per cent) in the Australian market. It also demonstrates that equity raised through rights based equity issues is around 50 per cent larger than that raised through placements. Associate Professor Handley reviewed additional data from KPMG and found a similar pattern of results.[663]

In considering the appropriate allowance for equity raising costs, the AER has analysed recent equity raising activities of regulated utilities in Australia, and considered the potential reasons for undertaking an SEO.[664] The AER has found that equity raisings often occur in order to fund organic growth of the business (internal expansion). In other cases, equity raising is required as a result of changes in business structure, business ownership or industry structure. Table E.5 provides the results of the AER's analysis.

Table E.5: Equity raised by Australian Utility Firms 1997–2008 ($m)

Purpose of SEO	Mergers and acquisitions	Unidentified purpose	Internal expansion	Total
Placements				
Private placement	2482	431	66	2979
Share placement plan	306	115	54	475
Total placement	2788	546	120	3454
Rights based equity				
DRP	–	–	1453	1453
Rights issue	1577	600	–	2177
Total rights issue	1577	600	1453	3630
Employee shares	–	94	–	94
Total	**4365**	**1240**	**1573**	**7178**

Source: AER analysis.

While the majority of equity raising activity could be easily allocated to either internal expansion or merger activity, 17 per cent of equity raising activity either could not be allocated to any purpose, or was identified as partially supporting both internal expansion and mergers. Despite the difficulty in allocating this remaining equity, the AER considers the analysis indicates a relationship between equity raising methods and the purpose for which the equity is raised.

663 Handley, April 2009, p. 23.

664 Sample included all equity raising activities between 1997 and 2008 for the following firms: DUET, AGL, AGL Energy, Origin, Babcock and Brown Power, SP AusNet, Alinta, Spark Infrastructure and Envestra. Data was collected from Bloomberg, annual reports, company releases and ASX announcements; initial public offerings were excluded.

Table E.5 shows that while there are a significant number of rights issues, placements are more often chosen to support the majority of merger or acquisition activities. The AER considers that the significant changes in capital structure that occur during a merger or acquisition undermine comparisons with the benchmark firm, which is assumed to only undertake organic growth.[665] In addition, the costs of placements during a merger may be offset by the synergies expected to be generated by the merger itself. As such, the AER considers that the indirect costs of placements are likely to be offset by the indirect benefits of the changes in business structure.

Table E.5 also demonstrates that rights issues are chosen to support the majority of organic growth, with 92 per cent of all identified internal expansion funded via DRP. Placements are used infrequently for internal expansion (approximately 8 per cent of the time). The AER considers that this data, sourced from a sample of Australian regulated utilities over the past decade, provides a more appropriate comparison for the circumstances of the benchmark firm than any other empirical evidence submitted to it to date.

Non–price differences between placements and rights based equity

CEG stated that direct pricing for placements is consistently above that of rights issues.[666] CEG argued that no rational firm would willingly pay more than necessary for equity, and therefore inferred that there must be unobserved additional costs for a rights issue.

The AER considers that this argument ignores the existence of non–price differences between placements and rights issues. Placements are an exceedingly fast method to raise additional capital.[667] Empirical research indicates that placements are chosen as an equity raising method by firms under significant financial stress.[668] Such firms are not necessarily selecting equity raising methods on a least–cost basis. The financial stress of these firms requires urgent capital raising regardless of costs, and firms may in fact pay a premium to ensure the equity issue occurs quickly.[669] Accordingly, the AER considers that CEG has inappropriately assumed the existence of unobserved costs of a rights issue, and that equity raising trends may actually reflect the market value of non–price characteristics.

The AER has considered how the benchmark firm might value such a non–price characteristic of equity raising methods. The benchmark regulated firm experiences relatively predictable cash flows, low information asymmetry and a stable industry sector. The AER considers it is reasonable to expect that the benchmark firm's capital raising activities would occur in a planned and timely matter. Given reasonable management, the benchmark firm will not face financial stress that induces it to make decisions on a least–time basis. Rather, the AER considers the benchmark firm will

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665 ACG, 2004, p. 4.

666 CEG, January 2009, pp.16–17, paragraphs 45–47, and pp. 19–20, paragraphs 56–60. See also Grundy, January 2009, pp. 5–7, paragraphs 14–22.

667 Carlton, January 2009 (EnergyAustralia), p. 6; Carlton, January 2009 (TransGrid), p. 17.

668 Brown, P., Gallery, G. and Goei, O., *Does market misevaluation help explain share market long–run underperformance following a seasoned equity issue?,* Accounting and Finance, 2006, vol. 46, pp. 191–219. Bayless, M. and Chaplinsky, S. J., *Is there a window of opportunity for seasoned equity issuance?*, Journal of Finance, 1996, vol. 51(1).

669 The AER notes that the price observed is not consistent with the efficient price outcome of both the seller and the buyer being unforced.

prepare to raise capital as necessary, and elect equity raising methods generally according to least cost.

Associate Professor Handley also noted the range of factors (timing, equality, certainty of outcome and voting control) that are considered by a firm when choosing the benchmark SEO method, and observed that these indirect costs and benefits did have explanatory power.[670] On this basis, Associate Professor Handley noted the AER statement that a discounted rights issue was the optimal SEO method for all circumstances,[671] but did not consider it to be 'a strong argument' relative to arguments concerning consistency with the regulatory framework.[672]

In conclusion, the AER has considered the evidence presented by the NSPs and their consultants on the selection of a benchmark SEO method. The AER rejects the argument that placements should be the exclusive SEO method chosen by the benchmark firm for the following reasons:

- the benchmark firm should not necessarily adopt the equity raising method used by the majority of the market, as the benchmark firm differs systematically from the average market firm
- the AER's analysis indicates that placements are not the predominant equity raising method in the market. Rather, rights based methods (including DRPs and rights issues) jointly dominate the market
- close examination of Australian utilities demonstrates that placements are mostly used to fund mergers or acquisitions. Equity raising for organic growth, which is the most relevant scenario for the benchmark firm, is principally characterised by DRPs
- any time advantage of placements is irrelevant to the benchmark firm facing stable financials and efficient management.

On this basis, the AER considers that the appropriate benchmark equity raising method should not be restricted to placements. The AER notes that the recent update of the unit cost of SEOs based on the ACG methodology included both rights issues and placements.

Other issues

Announcement effects

The AER acknowledges the existence of alternative definitions of indirect costs in the financial literature.[673] There is frequently a change in a firm's share price when an equity raising is announced, often labelled as an 'announcement effect'. Some researchers identify this as an indirect cost of the equity raising, reasoning that the

670 Handley, April 2009, p. 13.
671 AER, *TransGrid draft decision*, p. 141; AER, *Transend draft decision*, p. 194; and AER, *NSW DNSP draft decision*, p. 191.
672 Handley, April 2009, p. 13.
673 Handley, April 2009, p. 5, footnote 9.

equity issue precipitated the change in price.[674] The AER notes that announcement effects are not considered an indirect cost by CEG, who stated:[675]

> If an announcement of equity raising signals to investors an unanticipated cash–flow problem at the firm then any consequent fall in the firm's share price cannot be presumed to be a cost of raising equity.

The AER notes that this is also the conclusion drawn by Associate Professor Handley, who stated:[676]

> It is noted that underpricing costs may be measured in a number of different ways, and further, that a reference to underpricing is not a reference to the stock price reaction that may occur on announcement of the security issue.

It is on this basis that CEG argued that Ofgem's rejection of indirect costs in their 2006 price control review[677] was a rejection of announcement effects, not underpricing, and therefore irrelevant to the CEG claim for indirect costs. CEG stated:[678]

> However, the basis of the empirical estimates of indirect costs in our report was, unlike the discussion in Smithers and Co, based on underpricing not announcement effects. That is, indirect cost estimates in our report were based on the difference between the price at which equity traded on the stock market and the price at which it was simultaneously issued to new investors.[679]

The AER notes that Carlton frequently cited announcement effects when discussing the existence of indirect costs. For example:[680]

> The importance of take–up is demonstrated by the Balachandran et al results. They found that for rights issues where the subscription by existing shareholders was low the negative announcement period returns were –3.22%; these negative returns are economically significant, equating to about 6.5% of proceeds received. Firms with high levels of take–up recorded less negative returns of –0.63%.

The AER considers that the exclusion of announcement effects from the definition of indirect costs is appropriate. The AER notes the agreement on this matter by CEG.

Upward sloping supply of capital

The AER notes CEG's argument that the supply curve for capital is upward–sloping[681] implying that the AER should allow each NSP to continually increase returns to each set of new investors. This requires that the aggregate return to all investors would also increase over time, as the proportion of old investors decreases,

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674 See Eckbo, B., Masulis, R. and Nori, O., *Security offerings*; in Eckbo, B. (ed.), *Handbook of corporate finance*, Elsevier, 2007; cited by Handley, April 2009, p. 5, footnote 9.

675 CEG, *Memorandum*, February 2009, p. 2.

676 Handley, April 2009, p. 5.

677 OFGEM, *Transmission price control review: Final proposals*, 4 December 2006.

678 CEG, Memorandum, February 2009, p. 3.

679 CEG, Memorandum, February 2009, p. 3.

680 Carlton, January 2009 (EnergyAustralia), p. 10; Carlton, January 2009 (TransGrid), p. 22. See also Carlton, January 2009 (EnergyAustralia), pp. 7, 15, 16, 21; Carlton, January 2009 (TransGrid), pp. 18, 28, 35.

681 CEG, January 2009, p. 12, paragraph 32.

and new investors receive ever–increasing returns. The AER notes that this would occur despite all parameters set under the NER and the transitional chapter 6 rules, (including beta, market risk premium, debt risk premium, gamma and gearing) remaining constant. The AER considers this outcome is incompatible with the regulatory framework mandated by the NEL and NER.

Information asymmetry

The AER notes empirical evidence of share price changes around the issuance of right–based equity, and notes the Hansen (1989) explanation that these changes are due to transaction costs being placed on shareholders. However, the AER recognises that there are other plausible explanations in the academic literature for this empirical evidence. This includes Eckbo and Masulis (1992), who consider Hansen's argument along with other explanations (information asymmetry and agency reasons) for the rights offer paradox.[682] Eckbo and Masulis conclude that there is 'insufficient evidence to suggest that any of these alternative explanations can resolve the rights offer paradox'.[683] This research is particularly relevant given that information asymmetry is one area in which regulated utilities differ markedly from the market average. The 'adverse selection' model developed by Eckbo and Masulis derives share price effects from market attempts to determine the 'true' value of the business. For a benchmark firm, this force is entirely absent (given that all cash flow projections are perfectly transparent and regulated). This research is strengthened by Bohren, Eckbo and Michalsen (1997) who present further evidence that information flows determine the presence and level of underpricing in rights issues.[684]

The AER also notes a large body of research observing that firms issue equity capital to outside investors—that is, a placement rather than a rights issue—when the share price is overvalued. This includes studies by Myers and Majluf (1984), Karpoff and Lee (1991), Spiess and Affleck–Graves (1995), Bayless and Chaplinsky (1996), Jindra (2000), and Brown, Gallery and Goei (2006).[685] Importantly, this means that the observed placement underpricing is not actually a true cost to original investors, since the reduction in prices accompanying an equity raising simply returns their shares to their true worth. The outside investors, although paying a discount to the temporarily overvalued price, have still contributed the true worth of their share, and there is therefore no dilution effect for the original shareholders. Heron and Lie (2004) extend this argument by arguing that managers issue shares to outside investors (via placement) when overvalued and rights issues when undervalued. The

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682 Eckbo, B. E. and Masulis, R. W., *Adverse selection and the rights offer paradox*, Journal of Financial Economics, 1992, vol. 32, pp. 293–332.

683 Eckbo and Masulis, 1992, p. 295.

684 Bohren, O., Eckbo, B. E. and Michalsen, D., *Why underwrite rights offerings? Some new evidence*, Journal of Financial Economics, 1997, vol. 46(2), pp. 223–261.

685 Myers, S. C. and Majluf, N. S., *Corporate financing and investment decisions when firms have information that investors do not have*, Journal of Financial Economics, 1984, Volume 13(2), pp. 187–221; Karpoff, J. M. and Lee, D., *Insider trading before new issue announcements,* Financial Management, Spring 1991, vol. 20(1); Spiess, K. D. and Affleck–Graves, J., *Underperformance in long–run stock returns following seasoned equity offerings*, Journal of Financial Economics, 1995, vol. 38(3), pp. 243–267; Bayless, M. and Chaplinsky, S. J., *Is there a window of opportunity for seasoned equity issuance?,* Journal of Finance, March 1996, vol. 51(1); Jindra, J., *Seasoned equity offerings, overvaluation, and timing*, 2000; and Brown, P., Gallery, G. and Goei, O., *Does market misevaluation help explain share market long–run underperformance following a seasoned equity issue*?, Accounting and Finance, 2006, vol. 46, pp. 191–219.

authors conclude that a possible reason for low usage of rights issues in the US may be that the major motivation for equity raising is to sell equity when it is overvalued.

Cost of using retained earnings

The NSPs stated that the marginal cost of using retained earnings has not been considered by the AER, and for this reason the AER had underestimated the cost of raising equity.[686] CEG and Professor Grundy identified five reasons why using retained earnings as equity incurs costs:

- increasing retained earnings lowers the ability to distribute dividends, which therefore lowers the ability to distribute imputation credits to investors[687]
- use of retained earnings lowers the ability to distribute dividends, which causes the firm to deviate from the dividend expected by the current 'dividend clientele', who will react negatively to the firm's behaviour[688]
- using retained earnings avoids the public scrutiny associated with external equity raising, and this public scrutiny is valuable to the business as a signal to the market of the quality of the firm[689]
- use of retained earning delays cash flows to investors, which increases risk[690]
- use of retained earnings forces existing shareholders to reinvest in the firm, deviating from their preferred portfolio and incurring transaction costs or increases in risk from a loss of diversification.[691]

Accordingly, the NSPs' consultants proposed that a retained earnings allowance needs to be provided to the benchmark firm.[692] In arguing for this allowance, CEG reasoned that the first dollar of retained earnings had a marginal cost of zero. CEG considered that the marginal cost of each dollar remained zero, until the point at which the amount of retained earnings impacted negatively on the business, principally by reducing dividends below the normal dividend yield. At the point where external equity was preferred to the use of retained earnings, the marginal cost of each form of equity is assumed to be equal. Assuming a linear increase from zero to the cost of an SEO, CEG argued that the retained earnings allowance for the NSPs should be equal to half the unit cost of the SEO allowance. This allowance would be calculated only on the portion of retained earnings that negatively impact the firm.

The AER notes that this issue was not raised by any of the NSPs in their regulatory proposals, but is a new argument presented in the revised regulatory proposals.

The AER is not aware of any regulatory precedent for applying a cost to retained earnings. ACG stated in its 2004 report:[693]

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686 TransGrid, *Revised revenue proposal*, p. 81; Integral Energy, *Revised regulatory proposal*, p. 45; EnergyAustralia, *Revised regulatory proposal*, p. 48.
687 CEG, January 2009, p. 29, paragraph 96 and Grundy, January 2009, p. 10, paragraph 36.
688 Grundy, January 2009, p. 9, paragraph 34.
689 CEG, January 2009, pp. 29–30, paragraph 97; Grundy, January 2009, p. 10, paragraph 35.
690 CEG, January 2009, p. 30, paragraph 99.
691 CEG, January 2009, p. 30, paragraph 100.
692 CEG, January 2009, pp. 31–34, paragraphs 101–115.
693 ACG, 2004, p. 63.

> Retained earnings have no issue costs and are generally undertaken continuously by regulated entities.

Associate Professor Handley considered each of the arguments raised by the NSPs, and rejected them as either an inappropriate basis for an allowance—for instance, personal transaction costs—or as being adequately dealt with in the discounting process (cash flow profiles through WACC, and imputation credit distribution through gamma). Associate Professor Handley argued that although selection of optimal dividend yield was required for determination of external equity requirements, there was no consequent cost for use of retained earnings, and concluded:[694]

> In summary, it is my view that indirect costs associated with using retained earnings should not be allowed as a cost of raising equity capital.

The AER considers that the NSPs have not provided evidence that there is a cost to the benchmark firm from using retained earnings.

Theoretical consideration of retained earnings cost allowance

The AER agrees with CEG that the pecking order theory does not state explicitly that retained earnings always have zero marginal cost.[695] However, the AER considers that CEG's arguments for a retained earnings allowance do not stand up to scrutiny.

CEG and Professor Grundy argued that retained earnings incur a cost to the benchmark firm because they impair the distribution of imputation credits.[696] The AER notes that, since the benchmark equity raising cost cash flow analysis takes account of an appropriate level of benchmark dividends, no such cost of using retained earnings is incurred by the NSP.

Professor Grundy argued that the established dividend clientele would react negatively to a change in dividend levels as a result of increased retained earnings.[697] The AER does not consider that the assumptions concerning benchmark dividends in the benchmark equity raising cost cash flow analysis would result in any negative affect on the purported dividend clientele. Further detail on the AER's assessment of benchmark dividends is discussed below in this appendix.

CEG and Professor Grundy also argued that public scrutiny associated with external equity raising reduces costs to the benchmark firm.[698] The AER considers that this does not apply in the context of a regulated firm whose financial decisions are transparent, regardless of a specific equity issue. Accordingly, the AER considers that this proposed marginal cost of using retained earnings is not applicable in the context of the benchmark firm.

CEG also argued that the backdating of cash flows (via retained earnings) results in increased risk, and therefore, increased cost.[699] The AER considers that this result is dependent on the delayed distribution of dividends, in both the initial and later years

694 Handley, April 2009, p. 19.
695 CEG, January 2009, p. 32, paragraph 105.
696 CEG, January 2009, p. 29, paragraph 96 and Grundy, January 2009, p. 10, paragraph 36.
697 Grundy, January 2009, p. 9, paragraph 34.
698 CEG, January 2009, pp. 29–30, paragraph 97; Grundy, January 2009, p. 10, paragraph 35.
699 CEG, January 2009, p. 30, paragraph 99.

of the next regulatory control period. However, the AER notes that dividends are set, independent from the size of retained earnings. For each year, the benchmark dividend has been determined according to the amount of imputation credits earned in the post–tax revenue model (PTRM) (based on the relevant gamma), prior to deriving retained earnings.

In addition, the AER notes that such a risk increase applies regardless of the source of equity, since it is only dependent on the schedule of payments involved. All investment projects undertaken by the benchmark firm involve initial payments to establish infrastructure, which then return in later years (i.e. a 'backdated cash flow'). All projects would therefore add to 'interest rate risk'. The AER considers a proposed retained earnings allowance would, in effect, allow for NSPs to earn a higher rate of return. The AER consideration of the rate of return is set out in chapter 5 of this final decision.

CEG argued that use of retained earnings incurs costs associated with disrupting investors' preferred portfolios.[700] The AER notes that this is an argument regarding personal transaction costs, and that such arguments were considered in detail earlier in this appendix. The AER considers that no evidence has been provided that the overall transaction costs incurred by investing in a benchmark firm, even with a 'forced transaction,' would exceed the transaction costs from investing in the market portfolio.

The AER considers that the arguments concerning the implementation of a retained earnings allowance, as proposed by CEG, are flawed for the following reasons:

- the linear marginal cost increase from zero per cent to the cost of an SEO cannot be justified
- the average area under the (linear) marginal cost curve is overestimated by the half–of–SEO–percentage rule proposed by CEG
- the selection of the boundary points (minimal dividend yield and normal dividend yield) is contentious.

The AER notes that these flaws are cumulative in effect. The AER considers that, even if such an allowance was theoretically justified, the practical implementation proposed by CEG does not accurately measure the theoretical concept.

Conclusion on cost of using retained earnings

The AER has considered the evidence presented by the NSPs and their consultants on the cost of using retained earnings as a source of equity. The AER finds three key reasons to reject the proposals for a retained earnings cost allowance, each of which it considers are independently sufficient to reject the proposal:

- new methodology cannot be presented by an NSP in its revised revenue proposal
- there is no acceptable theoretical justification for a retained earnings cost allowance
- the implementation proposed by CEG systematically overestimates what it purports to measure and cannot be accepted as an accurate methodology.

700 CEG, January 2009, p. 30, paragraph 100.

On this basis, the AER rejects the claim for an allowance for the cost of using retained earnings.

E.2.4 Direct cost of raising equity

In previous transmission determinations, the AER has based its estimate of the direct cost of raising equity on the ACG methodology, which recommended a benchmark transaction cost of 3 per cent of the total equity raised.[701] ACG based this unit cost on an analysis of actual SEO raising costs (rights issues and placements) incurred by Australian companies between 1998 and 2004, noting the difficulty obtaining data from firms with characteristics matching that of the benchmark firm (regulated utilities who require funds for internal expansion). With this in mind, ACG adopted the 3 per cent as a conservative estimate, noting that it was 'an upper limit of the likely cost of an SEO associated with capital expenditure within existing regulated activities'.[702] This figure was updated by the AER in 2008, consistent with the ACG methodology, to 2.75 per cent.[703] The ACG methodology only includes rights issues and placements; it does not include dividend reinvestment plans.

The NSPs disputed the draft decision on direct equity raising costs but did not present an alternative unit cost in their revised proposals.[704] This is in keeping with the NSPs' expressed view that the direct and indirect costs of all capital raising are interdependent and should be jointly decided, and the re–submission of a combined unit cost of 7.6 per cent.[705] CEG decomposed the 7.6 per cent unit cost in its May 2008 report:

> We recommend adopting an estimate of 7.6%. This is approximately the same result as adding Bortolotti, Megginson and Smart's estimate of average global underpricing (4.5%) to the AER's current estimate of direct costs (3%). It is also consistent with the 7.6% estimate of total costs based on the work of Saunders, Palia and Kim (2003). It is also consistent with Lee Lochead and Ritter [sic] (1996) estimate of direct SEO costs for utilities (4.9%) plus the lowest available estimate for underpricing in SEOs (2.5% based on US estimates by Bortolotti et. al.)

The AER notes that the paper by Lee, Lochhead, Ritter and Zhao considers only domestic US firms raising capital in the US market. Accordingly, it is of limited relevance to the benchmark Australian firm raising equity in Australia.[706] Further, the AER notes that Lee et al excludes all rights issues, skewing the obtained estimate of direct costs by the elimination of a significant portion of SEOs. On this basis, the AER considers that the Lee, Lochhead, Ritter and Zhao estimate of direct equity raising costs is not relevant to the benchmark regulated firm in Australia.

No other breakdown of direct costs was provided in the January 2009 CEG report, the report by Professor Grundy or the Carlton report.

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701 ACG, 2004, pp. 64–69.

702 ACG, 2004, p. 65.

703 AER, *NSW DNSP draft decision*, p. 197, footnote 549.

704 TransGrid, *Revised revenue proposal*, pp. 79–82; EnergyAustralia, *Revised regulatory proposal*, pp. 44–47.

705 TransGrid, *Revised revenue proposal*, p. 82; EnergyAustralia, *Revised regulatory proposal*, p. 49.

706 Lee, I., Lochhead, S., Ritter, J. and Zhao, Q., *The costs of raising capital*, The Journal of Financial Research, vol. 19(1), pp. 59–74.

Associate Professor Handley noted the acceptance by the NSPs of the 3 per cent unit cost based on the ACG methodology. Associate Professor Handley suggested that a reasonable estimate of the direct cost of raising equity capital from placements and other sources (other than dividend reinvestment plans) was in the range 2.75–3 per cent.[707]

On the basis of its review and assessment of all the material put forward, the AER considers that an allowance of 2.75 per cent, based upon the ACG methodology is an appropriate unit cost for direct equity raising costs (other than DRPs).

Implications of the Ofgem decision

CEG argued that the consideration of Ofgem (the UK regulator) precedent should lead to an allowance of 5 per cent for direct equity raising costs,[708] since this was the final unit cost approved by Ofgem in its 2006 price control review.[709]

The AER observes that Ofgem was interested in firms in the United Kingdom when it assessed direct equity raising costs and established a market range of 5–12 per cent. The AER notes that research papers repeatedly find large differences between nations on equity raising costs.[710] Accordingly, in view of the numerous differences in economic, financial and regulatory frameworks between the two countries, the AER does not consider it appropriate to apply direct cost estimates from the United Kingdom to Australian firms.

The AER considers, however, that Ofgem's reasoning regarding the positioning of regulated utilities relative to average market position on equity raising costs is relevant. In both Australia and the UK, regulated utilities have lower information asymmetry, more stable cash flows and better known risk than the market average. Therefore, it is likely that the direct equity raising cost of regulated utilities will be systematically lower than the market wide average direct equity raising cost. This means that although the Ofgem range of 5–12 per cent is not relevant, the Ofgem policy of choosing the lower limit of the range may be of relevance for the AER when positioning likely benchmark direct equity raising costs of regulated utilities relative to the market average equity raising costs.

E2.4.1 Benchmark cash flow analysis—calculation of retained earnings and external equity requirements

In order to determine the amount of equity raising required in recent transmission determinations, the AER has undertaken an assessment of benchmark cash flows calculated in the PTRM. In summary, the analysis calculated the amount of retained earnings which was deducted from the equity portion of forecast capex. The resultant figure, if positive, represented the amount of new equity to be raised.

The NSPs submitted that the benchmark cash flow analysis applied in the draft decision was flawed because consistency was not maintained with the regulatory

707 Handley, April 2009, p. 26.

708 CEG, *Memorandum*, February 2009, p. 2.

709 OFGEM, *Transmission price control review: Final proposals*, 4 December 2006.

710 For example, Chen, H. and Ritter, J., *The seven percent solution*, Journal of Finance, June 1999; Gajewski, J. and Ginglinger, E. *Seasoned equity issues in a closely held market: Evidence from France*, European Finance Review, 2002, Vol 6, pp. 291–319.

benchmarks in the PTRM.[711] The issues identified by the NSPs and their consultants included:[712]

- the calculation and assumptions surrounding dividends including the measurement of net profit, payout ratios, implied dividend yields and distribution of imputation credits
- the lack of provision to repay the principal of existing debt.

Citing findings from a review by KPMG, Integral Energy made the following submission:[713]

> The PTRM does not provide sufficient cash flows to enable Integral Energy to pay out a level of dividends and associated imputation credits that is sufficient to support the value that is assumed to flow to shareholders from imputation credits. Under such circumstances the cash flow to equity providers will be lower than that assumed in the PTRM, resulting in a calculated return to equity holders that is lower than the benchmark cost of equity assumed in the inputs; and
>
> The value of imputation credits that is assumed to flow to shareholders in the PTRM can only be supported if dividend payout ratios well in excess of 100% is assumed each year. Even with a 100% dividend payout ratio, there are insufficient accounting profits available to distribute the required level of dividends and imputation credits.

Each of these issues is considered below, in addition to other cash flow issues identified by the AER.

Assessment of dividends

The AER's benchmark equity raising cash flow analysis includes an assessment of dividends that are to be subtracted from internal cash flows in the process of calculating the amount of retained earnings that is available for reinvestment through forecast capex. As the equity raising cash flow analysis is not part of the PTRM, the assumptions concerning dividends do not directly affect any cash flows in the PTRM (other than the allowance provided for equity raising costs).[714] However, as the AER has applied a benchmark approach to determining the appropriate allowance for

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711 A broad outline of the steps in the AER's benchmark equity raising cash flow analysis can be seen on page 142–143 of the draft decision on TransGrid's revenue proposal. These steps largely remain valid despite the issues considered in this final decision. Where the steps set out in the draft decision are no longer accurate, specific changes to the methodology are set out in this appendix.

712 For example, TransGrid, *Revised revenue proposal*, pp 80–81; EnergyAustralia, *Revised regulatory proposal*, pp. 47–48.

713 Integral Energy, *Submission,* 16 February 2009, p. 10.

714 Accordingly, claims by NSPs about the impact of the AER's cash flow analysis on returns to equity holders and the level of imputation credits that can be distributed, are only relevant to the consideration of the appropriate allowance for equity raising transaction costs. That is, the cash flow analysis and assumptions do not affect the PTRM or any of the building block calculations apart from the allowance for equity raising transaction costs.

equity raising costs,[715] it agrees with Associate Professor Handley that assumptions should be consistent with the overall regulatory framework.[716]

The NSPs noted that the effective dividend yield assumed in the draft decision was less than 3 per cent.[717] the NSPs submitted that a dividend yield of 8.6 per cent is sustainable in the long–run provided it is less than the return on equity.[718] TransGrid also stated that equity holders expect to receive their return on equity as dividends.[719] CEG was critical of the assumptions concerning the appropriate amount of dividends. While advocating a long–term benchmark dividend yield (rather than a payout ratio), CEG concluded that:[720]

> The appropriate dividend policy should be determined by reference to the level of economic profit. It cannot sensible [sic] be determined by reference to accounting profit (except where this is the best estimate of economic profit).

TransGrid and EnergyAustralia also submitted a report by Carlton which supported an alternative dividend policy based on 100 per cent distribution of imputation credits.[721] TransGrid and EnergyAustralia did not apply the recommendations of the report by Carlton, but suggested that there is merit in further review of his recommended approach.[722]

Integral Energy submitted that the inconsistency between the PTRM and the benchmark equity raising cash flow analysis was attributable to different measures of depreciation:[723]

> The net profit after tax is clearly inconsistent with the face value of imputation credits created for the same time period. This is evidence of the effect that incorporating income taxation, financial accounting and economic value within the PTRM can result in differing views of the same "transactions".
>
> The obvious difference between these three views of financial performance as represented in the PTRM relates to the calculation, application and timing of "depreciation".

Despite raising the concerns supported by it consultants' reports, in their revised regulatory proposals TransGrid, EnergyAustralia and Integral Energy applied dividend assumptions that were consistent with the draft decision. However, given the concerns and criticisms raised by the NSPs regarding the assumptions about dividends, the AER has given further consideration to this issue.

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715 This is in contrast to a direct estimate of the likely costs to be incurred by the regulated business, which in this case is likely to be negligible due to government ownership.

716 Handley, April 2009, pp. 30–33.

717 TransGrid, *Revised revenue proposal*, p. 81; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46.

718 TransGrid, *Revised revenue proposal*, p. 81; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46.

719 TransGrid, *Revised revenue proposal*, p. 81.

720 CEG, January 2009, p. 28.

721 Carlton, January 2009 (EnergyAustralia), pp. 27–29, section 3.2.

722 TransGrid, *Revised revenue proposal*, p. 82.

723 Integral Energy, *Submission*, 16 February 2009, Attachment 3, p. 3.

The PTRM, by design, does not include an assessment of dividends. However, the AER is required by the NER to assume a certain level of utilisation of imputation credits for a benchmark efficient entity when calculating the allowance for corporate income tax.[724] Ultimately, the value of imputation credits can only be realised in the hands of shareholders who may receive imputation credits attached to dividend payments. Accordingly, an issue of consistency arises between the assumed value of imputation credits in the PTRM and the amount of imputation credits that is assumed to be distributed in the AER's benchmark equity raising cash flow analysis.

As noted by Carlton, however, the level of dividends in the equity raising cash flow analysis in the draft decision was generally insufficient to distribute the amount of imputation credits assumed in the PTRM.[725] The dividends assumed in the draft decision were based on a 70 per cent payout ratio applied to accounting net profit after tax. Under the approach applied in the draft decision the degree to which imputation credits were distributed through dividends varied over time and between the businesses.

As required by the NER, the PTRM reduces the allowance for tax based on the assumption that investors receive a value for imputation credits equal to gamma (0.5) times the value of taxes payable. If sufficient imputation credits are not distributed via dividends for this to be achieved and shareholders receive less than the assumed benefit from imputation credits, then the PTRM will not achieve the design objective of providing investors with the expectation of achieving the benchmark return on equity.[726]

Accordingly, to maintain consistency between the assumptions and analysis of the PTRM, the AER considers it appropriate to amend the way dividends are derived in its benchmark equity raising cash flow analysis for this final decision. The AER considers that the approach advocated by Carlton—linking dividends to the amount of imputation credits calculated in the PTRM—has merit. However, the AER does not agree with all of the cash flow assumptions made by Carlton. In particular, the AER considers that the required payout ratio of imputation credits to achieve the value in the PTRM has been misunderstood.

Background to gamma estimate in the NER

In the draft decision, the AER determined that an imputation credit payout ratio estimated for the purposes of the gamma parameter (i.e. assumed utilisation of imputation credits) can provide a reasonable estimate of a dividend payout ratio to be used for the purposes of estimating equity raising costs.[727] In the draft decision, the

724 NER, clause 6A.5.3.

725 Carlton, January 2009 (EnergyAustralia), p. 26. See also KPMG, January 2009, pp. 10–11.

726 Under the National Tax Equivalence Regime, the government owned business makes tax equivalent payments to the government (the tax collector as well as the shareholder). While the shareholder may also receive dividends, in this instance it is not able to make any use of imputation credits. It does however receive the full value of tax equivalent payments made (to itself), which is equivalent to a privately owned firm receiving the full value of the potential imputation credits regardless of whether there is any dividend or not. In fact, regardless of the assumed value of gamma, the return to the government will be the same. Therefore the assumed dividend payout in this instance cannot compromise the intended benefits of imputation credits to these shareholders.

727 It is noted that these two payout ratios may not necessarily coincide, as in practice there are methods available to distribute imputation credits other than by attachment to a normal declared

AER stated that a 70 per cent dividend payout ratio is considered as consistent with clause 6A.6.4(a) of the NER and clause 6.5.3 of transitional chapter 6 rules, which deems the utilisation of imputation credits to be 0.5.[728]

This observation was made in the ACCC's TransGrid 2004 draft decision,[729] which informed its view that the assumed utilisation of imputation credits be 0.5 in the 2004 Statement of Regulatory Principles (SRP).[730] The Statement of Regulatory principles subsequently formed the basis of the NER requirement for a gamma of 0.5. Specifically, the ACCC stated that estimates of the average value of imputation credits once distributed, ranged between 50 and 90 per cent.[731] The decision also cited an average dividend payout ratio of approximately 70 per cent before concluding that the gamma value should be 0.5.[732] It is apparent that this conclusion is the product of approximately 70 per cent payout ratio and approximately 70 per cent average valuation (around the middle of the stated range).

The AER's WACC review

In December 2008, the AER proposed that the assumed utilisation of imputation credits (i.e. gamma) be increased from 0.5 to 0.65.[733] One of the key assumptions supporting the AER's proposed position on gamma was an imputation credit payout ratio of 100 per cent, following the recommendation of the AER's consultant, Associate Professor Handley. In his report Associate Professor Handley argued that:[734]

> …the generally accepted approach by regulators is to define the value of imputation credits as the product of a credit distribution or payout ratio – representing the proportion of credits generated that are distributed to shareholders, and a credit utilisation or redemption rate – representing the value of a distributed credit…
>
> An alternative view is that a decomposition of gamma along these lines is unnecessary since, for valuation purposes, it is appropriate to assume the distribution ratio is equal to one.

As noted above, the AER stated in its draft decision that the assumed payout ratio of 70 per cent was consistent with the gamma estimate of 0.5 specified by the NER. That is, the estimate of a gamma of 0.5 in the NER was the product of an assumed payout ratio and an assumed utilisation rate.[735] However, Carlton suggested that the payout assumption is required to be 100 per cent citing the AER's WACC explanatory

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dividend (for example, special dividends, off-market share buybacks and DRPs). See AER, *Electricity transmission and distribution network service providers: Review of the weighted average cost of capital (WACC) parameters: Explanatory statement*, 12 December 2008, p. 301.

728 AER, *NSW DNSP draft decision*, p. 195, footnote 547.

729 ACCC, *NSW and ACT Transmission Network Revenue Caps– TransGrid 2004/05–2008/09: Draft decision*, 28 April 2004, pp. 87–88.

730 ACCC, *Statement of principles for the regulation of electricity transmission revenues: Decision*, 8 December 2004, p. 17, point 8.9.

731 ACCC, *TransGrid draft decision*, April 2004, p. 87.

732 ACCC, *TransGrid draft decision*, April 2004, p. 87, footnote 54.

733 AER, *WACC review: Explanatory statement*, 12 December 2008, pp. 13–14.

734 Handley, J.C., *A note on the valuation of imputation credits*, 12 November 2008, p. 4.

735 The product of ~0.7 (payout ratio) and ~0.7 (utilisation) is 0.5, consistent with the required gamma value specified in the NER.

statement that indicates an assumption that 100 per cent of imputation credits are paid out.[736] A similar view was put forward by SFG and KPMG.[737]

The AER does not accept this argument for the purposes of this final decision. As Associate Professor Handley articulates in his report, the assumption of a payout ratio of 100 per cent for valuation purposes represents a departure from the 'generally accepted regulatory practice', which effectively assumes a zero value for retained imputation credits (i.e. 'the Monkhouse approach'). As the prescribed gamma value of 0.5 was estimated on the basis of the Monkhouse approach, the views received from Associate Professor Handley as part of the WACC review are not a relevant consideration for the purposes of this final decision.

The AER maintains that the imputation credit payout ratio assumed for the purposes of estimating the gamma parameter required under the NER provides a reasonable estimate of the dividend payout ratio to be used for the purposes of estimating equity raising costs under the cash flow analysis. Accordingly, the AER considers that a payout ratio of 70 per cent is appropriate for the purposes of this final decision.

Consideration of methodology for setting dividends

The AER notes the criticism concerning the apparent disconnect between the PTRM valuation of imputation credits and the value shareholders would actually receive under the draft decision.[738] Carlton stated that for EnergyAustralia, the AER had assumed imputation credits of $292 million in the PTRM while shareholders would only be able to realise a value of $130 million through assumed dividends.

This apparent disconnect arises from two sources. The first relates to the assumption about the value of a distributed imputation credit. Carlton's assumed payout ratio of 100 per cent, to achieve a gamma value of 0.5, relies on 50 per cent utilisation by shareholders. Conversely, as set out above, the AER has indicated that a gamma value of 0.5 is consistent with a payout ratio of about 70 per cent, and about 70 per cent utilisation by shareholders. Adjusting for this misinterpretation of the gamma estimate in the NER, the comparison becomes $292 million in the PTRM and about $182 million ($260 million × 70 per cent) for the realised value of distributed imputation credits under the benchmark equity raising cost cash flow analysis.[739] However, Carlton's point remains valid. That is, imputation credits assumed in the PTRM are greater than the assumed distribution and subsequent valuation of imputation credits within the benchmark equity raising cost cash flow analysis.

Accordingly, to address the issue in its equity raising cash flow analysis, the AER has assumed that dividends are equal to the amount required to distribute 70 per cent of total imputation credits assumed to be earned in the PTRM (total imputation credits earned is equivalent to tax paid). This amount is calculated according to the formula:

$$\text{Dividends} = \left(\frac{\text{Imputation credits earned}}{\text{tax rate}}\right) \times \left(1 - \text{tax rate}\right) \times \text{payout ratio}$$

736 Carlton, January 2009 (EnergyAustralia), p. 26; Carlton, January 2009 (TransGrid), pp. 5–6.

737 SFG, March 2009, pp. 14–15, paragraphs 58–61; KPMG, January 2009, p. 2.

738 Carlton, January 2009 (EnergyAustralia), pp. 23–26, section 3.1.

739 The figure of $260 million is the amount of imputation credits that could be distributed through dividends assumed in the draft decision benchmark equity raising cash flow analysis.

The AER's amendment to the dividend policy applied in the draft decision rectifies the remaining disconnect between the value assumed for imputation credits in the PTRM and in the benchmark equity raising cash flow analysis. The AER has confirmed that for each of the relevant NSPs, the assumed value of imputation credits in the PTRM is consistent with the value realised by shareholders (after being distributed with dividends and utilised by shareholders).[740] This is consistent with the derivation of the gamma value specified in the NER of 0.5.

The AER notes that the dividend yield implied by this approach will vary from business to business and year to year, as it is driven by the amount of the tax building block in the PTRM relative to the RAB. However, the AER considers that consistency between the assumptions made in the PTRM and in the equity raising cash flow analysis is of greater importance than the implied dividend yield in this instance.

Inclusion of a dividend reinvestment plan

The AER's estimate of benchmark equity raising costs for recent transmission determinations has been based on the ACG methodology. However the AER has not taken DRPs into account. To the extent that the cost of raising equity through DRPs[741] is less than the benchmark cost applied in the ACG methodology, the AER's recent determinations have overstated the appropriate cost of raising equity through DRPs. The AER applied a benchmark direct unit cost of 2.75 per cent in its draft decision. While Carlton has suggested that indirect costs associated with DRPs should be taken into account,[742] as discussed above, the AER considers that an allowance for such costs would be inappropriate. This view is supported by Associate Professor Handley.[743]

Direct costs of equity raised through a dividend reinvestment plan

The ACG suggested that the costs of raising equity should be zero. ACG noted that even when DRPs are underwritten, the level of competition among brokers resulted in no cost for underwriting services as brokers sought to profit by placing stock at a higher price than the standard DRP price.[744] Carlton stated that anecdotal evidence suggests that underwriting fees of around 2.5 per cent are being charged for DRP underwriting.[745] On the basis of the ACG and Carlton estimates, Associate Professor Handley stated that a reasonable estimate of the cost of a DRP is between zero and 2.5 per cent.[746]

However further investigation of Carlton's anecdotal evidence reveals that the figure of 2.5 per cent was only applicable to the portion of equity taken up by the underwriter. In this instance the take up by the underwriter was about half of the

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740 For the amounts to precisely equate, the assumed utilisation of imputation credits by shareholders is calculated to be 71 per cent.

741 ACG suggested that the cost of raising equity through a DRP should be zero. ACG, 2004, p. 63.

742 Carlton, January 2009 (EnergyAustralia), pp. 29–30; Carlton, January 2009 (TransGrid), pp. 35–36.

743 Handley, April 2009, pp. 23–24.

744 ACG, 2004, p. 63.

745 Carlton, January 2009 (EnergyAustralia), pp. 29–30; Carlton, January 2009 (TransGrid), p. 36.

746 Handley, April 2009, pp. 26–27.

capital raised which, in turn, implies that the underwriting cost as a percentage of equity raised is about half of 2.5 per cent.[747]

The AER has undertaken its own research of the costs of DRPs among domestic energy network businesses. The AER observed that where reported, costs as a portion of equity raised had a median of 0.75 per cent and a mean of 1 per cent.[748] On the basis of all the information considered including the ACG report and Carlton's anecdotal evidence, the AER considers that a conservative estimate of 1 per cent is appropriate. The AER considers that this figure is the appropriate unit cost to be applied to the amount of equity assumed to be raised through a DRP.

Amount of equity assumed to be raised through a dividend reinvestment plan

Associate Professor Handley advised that a reasonable estimate of the amount of equity to be raised by a DRP was 30 per cent. This was based on the observation of the equity raised through DRPs in the Australian market.[749] However, the ACG and Carlton support an estimate of 30 per cent reinvestment of dividends.[750] To reiterate, Associate Professor Handley suggested applying the percentage to required equity, while the ACG and Carlton suggested applying the percentage to the amount of dividends paid. Carlton included data from selected DRPs with an average of 34 per cent reinvestment of dividends.[751] The AER analysed data for Australian energy network businesses and found that about 30 per cent of dividends distributed were returned through a DRP.[752]

On balance the AER considers that it is reasonable to assume that the amount of equity to be raised by a DRP is 30 per cent of dividends paid. Whether this is greater or less than the approach considered reasonable by Associate Professor Handley will depend on the relative magnitude of dividends paid and required equity.[753] However, the AER considers it appropriate to link the level of dividend reinvestment to the assumed dividend payout rather than the total equity required. This will ensure that the assumptions within the equity raising cash flow analysis are internally consistent.

Accordingly, in its benchmark equity raising cash flow analysis the AER has assumed that 30 per cent of dividends paid are available for reinvestment at a cost of 1 per cent. Any further requirement for equity is assumed to come from external sources at a cost of 2.75 per cent as discussed above.

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747 Carlton, January 2009 (EnergyAustralia), pp.–41, appendix 4; Carlton, January 2009 (TransGrid), p. 49. The AER notes that 44 percent of dividends were reinvested with the underwriter taking up 22.6 per cent.

748 AER assessment of Bloomberg data and annual reports.

749 Handley, April 2009, pp. 23 and 26.

750 Carlton, January 2009 (TransGrid), p.36; ACG, 2004, p. 63.

751 Carlton, January 2009 (TransGrid), pp. 48–49.

752 AER assessment of data sourced from Bloomberg.

753 Further, while unlikely, where the DRP amount is linked to required equity, a scenario in which proposed capex is relatively high and taxes are relatively low could result in the amount of equity assumed to be sourced from DRP in excess of dividend payments.

Lack of provision for the repayment of existing debt

The NSPs applied a negative adjustment to retained earnings to allow for the repayment of debt. The justification for the adjustment is that it is required to maintain the benchmark gearing ratio.[754]

The NER requires the AER to set a WACC for the regulatory control period which includes setting the nominal risk free rate and the debt risk premium, both with reference to bonds with maturity of 10 years. Under this framework, debt is assumed to be refinanced by the benchmark firm for each regulatory control period. Such financing arrangements do not include any presumption of debt repayment during that period.

However, the PTRM does assume that the level of debt varies from year to year in accordance with movements in the RAB. That is, when the RAB increases, so does the benchmark level of debt along with the benchmark return on debt (interest payments). As the NSPs' RABs are increasing over the next regulatory control period, the AER considers that the benchmark level of debt should increase, not decrease (repayment of debt would decrease debt). This can be seen in the row of the analysis sheet of the PTRM titled 'Repayment of debt'. The fact that this cell contains a negative number in each year of the next regulatory control period confirms that the level of debt is increasing rather than decreasing. Accordingly, the AER considers that the adjustment labelled as repayment of debt is potentially misleading.

The NSPs' justification for its amendment to include repayment of debt into the cash flow analysis was to maintain the benchmark gearing assumption in the PTRM.[755] While not explicitly required by the NER, as discussed above in the context of setting the dividend assumptions, the AER considers it appropriate that the equity raising cash flow analysis aligns with the benchmark gearing assumption required in determining the WACC (and applied in the PTRM). The AER's cash flow analysis for the draft decision has assumed that 60 per cent of capex would be funded by new debt. This appears to be consistent with the benchmark gearing specified in the NER. However, to maintain benchmark levels of gearing, the level of debt must equal 60 per cent of the RAB value (rather than 60 per cent of capex).

Accordingly, to maintain consistency between the benchmark equity raising cash flow analysis and the PTRM, where the RAB increase is less than the expected capex (due to regulatory depreciation), the increase in debt must be less than 60 per cent of capex. Put another way, the amount of capex funded by debt is constrained by the amount of the increase in the debt portion of the RAB. The AER has amended the cash flow analysis from its draft decision such that the increase in debt funding is linked to the row of the analysis sheet of the PTRM titled 'Repayment of debt',[756] rather than being calculated as 60 per cent of capex. The residual of capex less the

754 TransGrid, *Revised revenue proposal*, pp. 80–81, point (e); Transend, *Revised revenue proposal*, p. 60; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46.

755 TransGrid, *Revised revenue proposal*, pp. 80–81, point (e); Transend, *Revised revenue proposal*, p. 60; EnergyAustralia, *Revised regulatory proposal*, p. 48 and Integral Energy, *Revised regulatory proposal*, p. 46.

756 The repayment of debt is multiplied by minus 1 in order to express the debt component of capex as a positive number.

increase in debt funding is the amount of capex that must be funded through retained earnings and then new equity.[757]

The effect of this adjustment in dollar terms is consistent with the amendment proposed by CEG and adopted in the revised regulatory proposals. However, it also overcomes the inconsistency of an adjustment to repay debt where the RAB is increasing and the regulatory framework assumes debt is refinanced every regulatory control period (rather than repaid). The adjustment implicitly recognises that a portion of retained earnings is attributable to debt rather than entirely equity.

Adjustment to forecast capex funding requirement

The AER identified an error in the value assumed to be the funding requirement for capex in the draft decision and in the subsequent revised regulatory proposals. The value inappropriately included an adjustment to increase expected capex by the WACC for half a year. This is done in the PTRM to provide a return on capex during the year it is incurred based on the assumed timing of the incurrence of capex. However, for financing purposes, it is only the net capex value rather than the 'grossed–up' capex value that is of relevance. The AER has therefore corrected this error in its benchmark equity raising cash flow analysis. This results in a lower forecast capex funding requirement.

E.2.4.1 Amortisation of allowance

In its draft decision for the NSW DNSPs, the AER expressed a preference for treating an equity raising cost allowance as part of the RAB—that is, to amortise the allowance.[758] This approach is consistent with the AER's 2006 Powerlink transmission determination, which considered the benchmark cash flow analysis to determine the extent of equity raising cost associated with forecast capex for the first time. The AER considers that although the amortisation treatment is equivalent in net present value terms to a perpetuity income stream provided as part of the opex allowance, there are several advantages to this approach:

- it ensures a transparent link between the equity raising cost and the capex that required the equity raising
- it eases administrative implementation in future regulatory resets
- it implements the recommendation made by ACG in its 2004 report.[759]

In accordance with the AER's previous approach, the benchmark equity raising cost allowance for the NSPs will be amortised over the weighted average standard life of

[757] Using the example described by CEG on page 22–23 of its January 2009 report, the RAB increases from \$100 to \$200 from one year to the next after taking into account depreciation of \$100 and capex of \$200. In its revised benchmark equity raising cash flow analysis, the AER has assumed the debt component of capex is given as the benchmark gearing ratio (60 per cent) multiplied by the increase in RAB value (\$200 less \$100), that is \$60. The AER's previous approach assumed that the debt component of capex was 60 per cent of \$200 (forecast capex).

[758] AER, *NSW DNSP draft decision*, p. 197. Note that the preference was not expressed in the TransGrid, Transend, and ActewAGL draft decisions because these draft decisions did not include any such allowance.

[759] ACG, 2004, p. xiii.

the relevant RAB for the purpose of providing the equity raising cost allowance associated with forecast capex for the next regulatory control period.

E.2.5 Summary of equity raising cost considerations

The AER has considered the arguments made by the NSPs on equity raising costs associated with forecast capex, including consultant reports and submissions.

The AER considers that there is no basis on which to accept the proposed allowance for indirect equity raising costs. The AER notes that personal transaction costs are not an appropriate justification for an allowance under the regulatory framework. Similarly, the AER notes that arguments relying on wealth transfer between investors are not appropriate justification for an allowance, since the regulatory framework specifies investor return in aggregate.

The AER rejects the argument that the benchmark firm would exclusively use placements to issue equity, finding that placements are not the majority market practice. Additionally, the AER considers that the characteristics of the benchmark firm may vary substantially from the market average, such that it would not be bound by majority market practice in any case.

The AER considers that the best estimate of the direct costs of equity raising is 2.75 per cent, the benchmark unit rate calculated in accordance with the ACG methodology and applied in the draft decision. The AER rejects the alternative estimates of direct equity raising costs proposed by the NSPs on the grounds that they deviate substantially from the equity raising conditions relevant to the benchmark firm.

The AER considers that there is a need to adjust the benchmark cash flow analysis to ensure that the gearing ratio is maintained, by linking the debt contribution to capex to the change in RAB each year. Further, the AER has set the dividend level to ensure that the dividends distribute the value of imputation credits assumed in the PTRM (which is based on the assumed gamma value prescribed under the NER). The AER also notes the prevalence of DRPs as a method for raising equity, and adjusts the benchmark cash flow analysis to allow 30 per cent of dividends to be reinvested via DRP at a benchmark cost of 1 per cent of the amount reinvested.

The AER considers that there is no evidence on which to provide an allowance for the proposed costs of using retained earnings as a source of equity.

For each NSP, the AER will apply the amended benchmark cash flow analysis and determine the amount that will be reinvested via DRP over the next regulatory control period. The allowance for the DRP cost will be 1 per cent of the amount reinvested in this way. The AER will then determine the amount of external equity required for the next regulatory control period in excess of that provided by the DRP. The allowance for external equity raising cost will be 2.75 per cent of the amount raised in this way. The two allowances will then be added to the RAB, and amortised over the weighted average standard life of the RAB.

Appendix F: Parameter definitions

The following parameter definitions apply to Transend during its next regulatory control period.

Parameter 1	Transmission circuit availability
Sub-parameters	Transmission line circuit availability (critical circuits) Transmission line circuit availability (non-critical circuits) Transformer circuit availability
Unit of measure	Percentage of total possible hours available
Source of data	Transend performance reporting system
Definition/formula	Formula: $\left(\dfrac{\text{No. hours per annum circuits are available}}{\text{Total possible no. of defined circuit hours}}\right)\times 100$ Definition: the actual circuit hours available divided by the total possible defined circuit hours available Critical circuits are those lines which are in areas under direct NEMMCO oversight (except radial portions on the *transmission system*) Non-critical circuits are lines in areas under indirect NEMMCO oversight and the radial portions of the *transmission system* that are under direct NEMMCO oversight
Inclusions	‘Circuits’ includes overhead lines, underground cables, and power transformers Circuit outages from all causes include planned, forced and emergency events, including extreme events
Exclusions	Outages on assets that are not providing *prescribed transmission services* Dedicated connection assets that supply a customer who has negotiated a higher (or lower) level of service required by the NER, where that customer has agreed to the cost (or discount) for that higher (or lower) level of service Circuit outages caused by a fault or other event on a third party system e.g. intertrip signal, generator outage (including coincident outages), customer installation (including a customer request), or by direction of fire services or NEMMCO. *Force majeure* events

Parameter 2	**Loss of supply event frequency**
Sub-parameter	Frequency of events where loss of supply exceeds 0.1 minutes Frequency of events where loss of supply exceeds 1.0 minutes
Unit of measure	Number of events per annum
Source of data	Transend performance reporting system
Definition/formula	Number of events greater than 0.1 system minutes per annum Number of events greater than 1.0 system minutes per annum System minutes are calculated for each supply interruption by the ‘load integration method’ using the following formula: $\frac{\Sigma \text{ (MWh unsupplied} \times 60)}{\text{MW peak demand}}$ 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 Transend offers supply restoration to the customer MW peak demand means the maximum amount of aggregated electricity demand recorded at entry points to the Transend transmission network and interconnector connection points during the financial year in which the event occurs or at any time previously The performance parameter applies to exit points only Interruptions affecting multiple connection points at exactly the same time are aggregated (i.e. system minutes are calculated by events rather than connection point interruptions)
Inclusions	All unplanned outages exceeding the specified impact (that is, 0.1 minutes and 1.0 minutes) Unplanned outages on all parts of the regulated transmission system Extreme events
Exclusions	Outages on assets that are not providing *prescribed transmission services* Dedicated connection assets that supply a customer that has negotiated a higher (or lower) level of service required by the NER, where that customer has agreed to the cost (or discount) for that higher (or lower) level of service Circuit outages caused by a fault of other even on a third party system e.g. intertrip signal, generator outage (including coincident outages), customer installation (including a customer request), or by direction of fire services or NEMMCO. Planned outages *Force majeure* events

Parameter 3	Average outage duration
Sub-parameters	Transmission Line Circuits Transformer Circuits
Unit of measure	Minutes
Source of data	Transend performance reporting system
Definition/formula	<u>Aggregate minutes of all unplanned outages</u> Number of events The cumulative summation of the outage duration time for the period, divided by the number of outage events during the period Where: outage duration time starts when a loss of supply occurs and ends when Transend offers supply restoration to the customer
Inclusions	Where notification to affected customers is less than 24 hours (except where NEMMCO reschedules the outage after notification has been provided.)
Exclusions	Successful reclose events (less than one minute duration) Outages on assets that are not providing *prescribed transmission services* Dedicated connection assets that supply a customer who has negotiated a higher (or lower) level of service required by the NER, where that customer has agreed to the cost (or discount) for that higher (or lower) level of service Circuit outages caused by a fault or other event on a third party system e.g. intertrip signal, generator outage (including coincident outage), fire services direction, customer installation (including a customer request), or by direction by fire services or NEMMCO Planned outages *Force majeure* events For all outages the duration is capped at seven days

Appendix G: Performance incentive curves

The following tables and figures represent the scale of the financial penalty or reward (y-axis) resulting from Transend's performance (x-axis) against each of its parameters. Tables G.1 to G.7 shows the set of linear equations presented in figures G.1 to G.7.

In accordance with the service target performance incentive scheme the s-factor result for each calendar year should be determined by the following formula:

$$S_{ct} = S_1 + S_2 + S_3 + S_4 + S_5 + S_6 + S_7$$

where:

S_{ct} = the total service standards factor (s-factor)

ct = the time period/calendar year

S_1 = s-factor for transmission line circuit availability (critical)

S_2 = s-factor for transmission line circuit availability (non-critical)

S_3 = s-factor for transformer circuit availability

S_4 = loss of supply event frequency > 0.1 system minutes

S_5 = loss of supply event frequency > 1.0 system minutes

S_6 = average outage duration - transmission line

S_7 = average outage duration - transformer

Note: Both average outage duration parameters has been given a zero weighting and therefore do not affect Transend's s-factor result during the next regulatory control period.

Figure G.1: Transmission line circuit availability (critical)

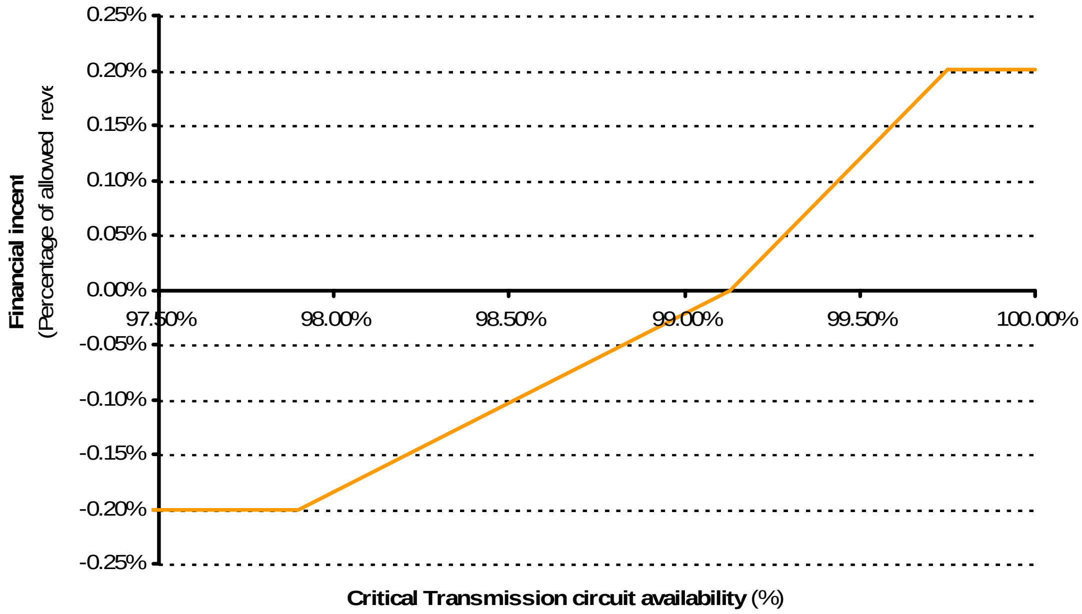

Table G.1: Transmission line circuit availability (critical)

							Where:				
S1	=	–0.002000							Availability	<	97.90%
S1	=	0.162602	x	Availability	+	–0.161187	97.90%	≤	Availability	≤	99.13%
S1	=	0.322581	x	Availability	+	–0.319774	99.13%	≤	Availability	≤	99.75%
S1	=	0.002000					99.75%	<	Availability		

Figure G.2: Transmission circuit availability (non-critical)

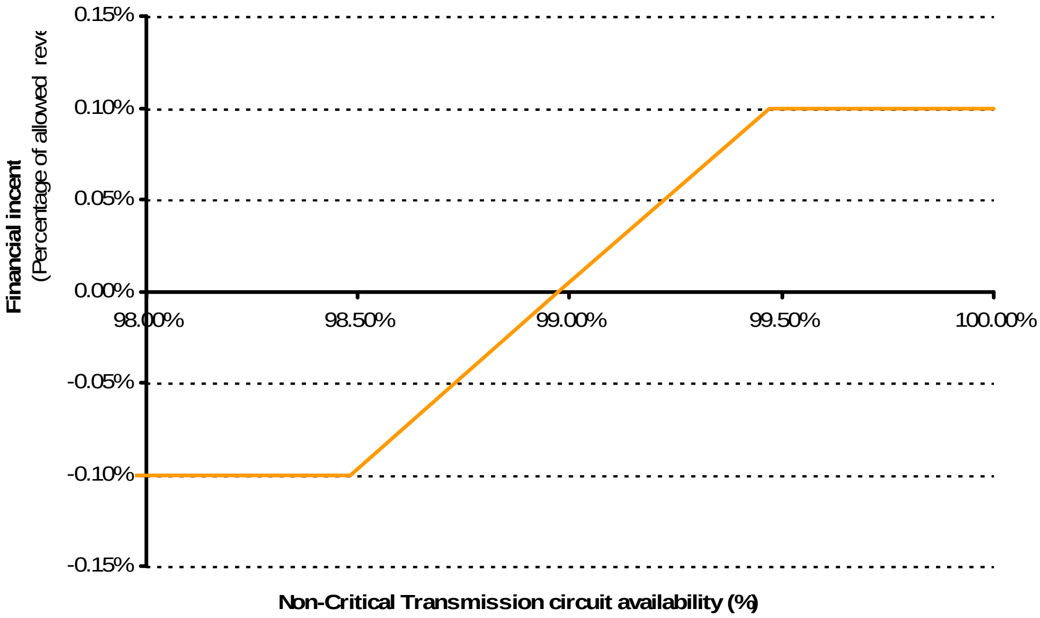

Table G.2: Transmission circuit availability (non-critical)

							Where:				
S2	=	–0.001000							Availability	<	98.48%
S2	=	0.204082	x	Availability	+	–0.201980	98.48%	≤	Availability	≤	98.97%
S2	=	0.200000	x	Availability	+	–0.197940	98.97%	≤	Availability	≤	99.47%
S2	=	0.001000					99.47%	<	Availability		

Figure G.3: Transformer circuit availability

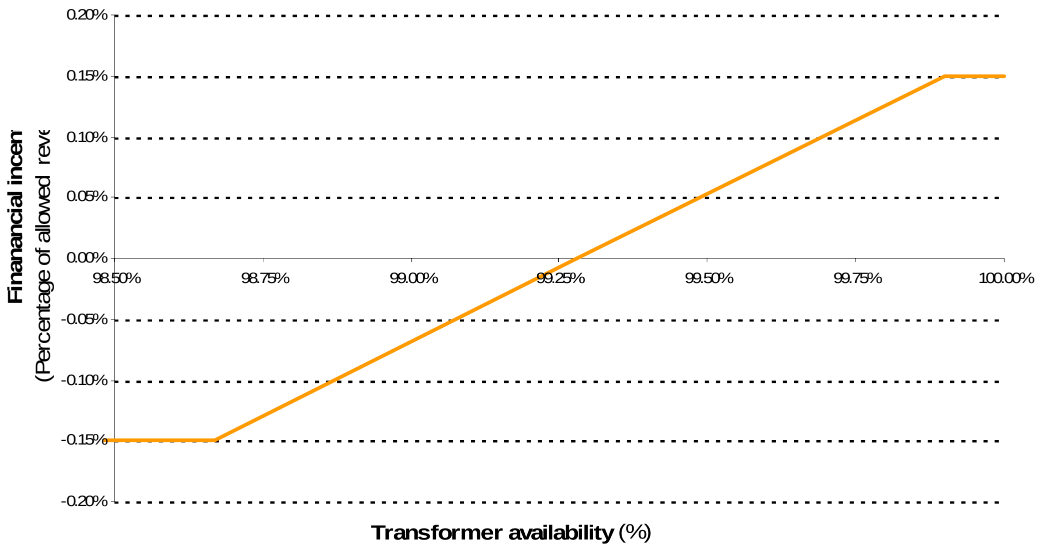

Table G.3: Transformer circuit availability

							Where:				
S2	=	–0.001500							Availability	<	98.67%
S2	=	0.245902	x	Availability	+	–0.244131	98.67%	≤	Availability	≤	98.28%
S2	=	0.241935	x	Availability	+	–0.240194	98.28%	≤	Availability	≤	99.90%
S2	=	0.001500					99.90%	<	Availability		

Figure G.4: Loss of supply event frequency > 0.1 system minutes

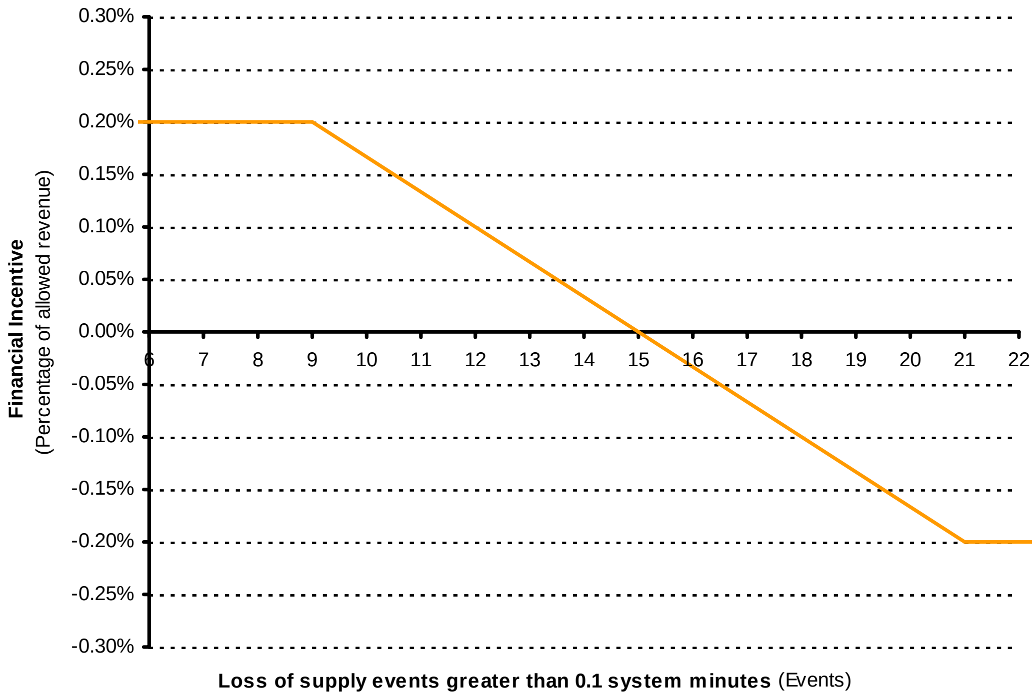

Table G.4: Loss of supply event frequency > 0.1 system minutes

							Where:					
S3	=	–0.002000					21	<	No. of events		
S3	=	–0.000333	x	No. of events	+	0.005000	15	≤	No. of events	≤	21
S3	=	–0.000286	x	No. of events	+	0.004286	8	≤	No. of events	≤	15
S3	=	0.002000							No. of events	<	9

Figure G.5: Loss of supply event frequency > 1.0 system minutes

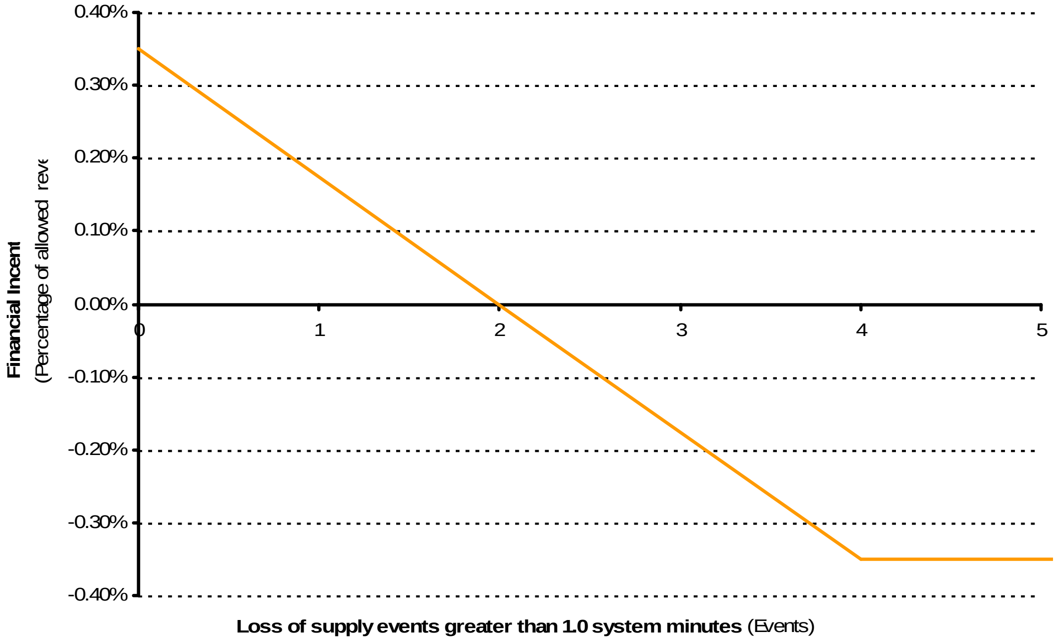

Table G.5: Loss of supply event frequency > 1.0 system minutes

							Where:					
S4	=	–0.003500					4	<	No. of events			
S4	=	–0.001750	x	No. of events	+	0.003500	2	≤	No. of events	≤	4	
S4	=	–0.001750	x	No. of events	+	0.003500	0	≤	No. of events	≤	2	
S4	=	0.003500							No. of events	<	0	

Figure G.6: Average outage duration – transmission lines

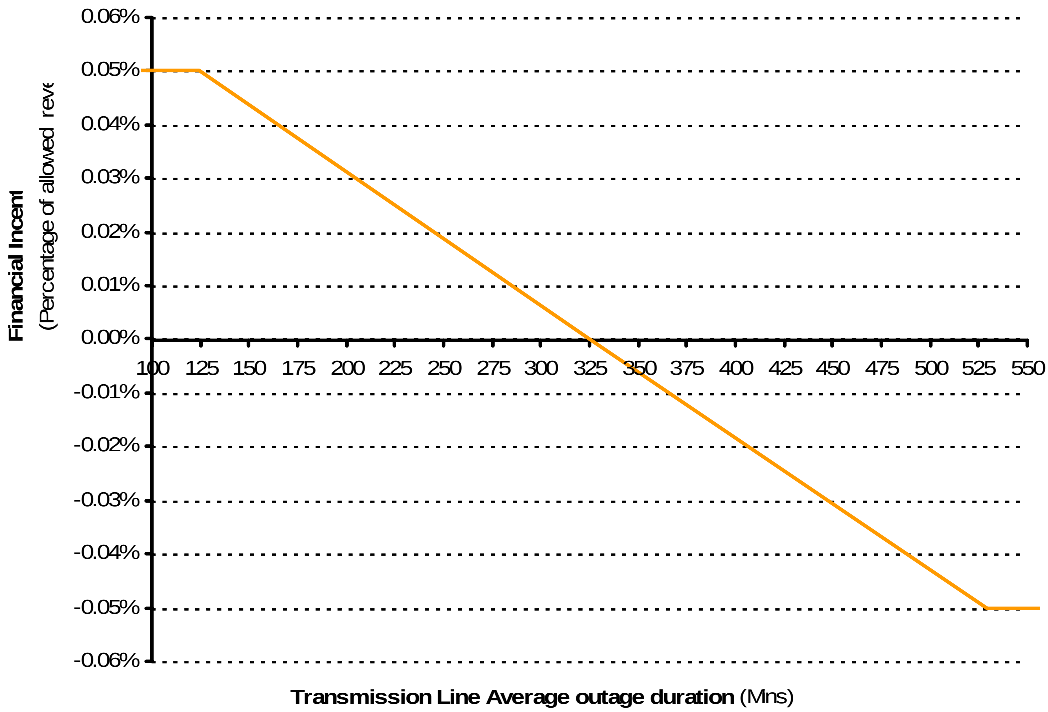

Table G.6: Average outage duration – transmission lines*

							Where:					
S5	=	–0.000500					529	<	Average outage duration		
S5	=	–0.000002	x	Average outage duration	+	0.000803	326	≤	Average outage duration	≤	529
S5	=	–0.000002	x	Average outage duration	+	0.000807	124	≤	Average outage duration	≤	326
S5	=	0.000500							Average outage duration	<	124

* Please note Transend has no revenue at risk against this measure. The 5% measure presented above is purely for illustrative purposes.

Figure G.7: Average outage duration – transformers

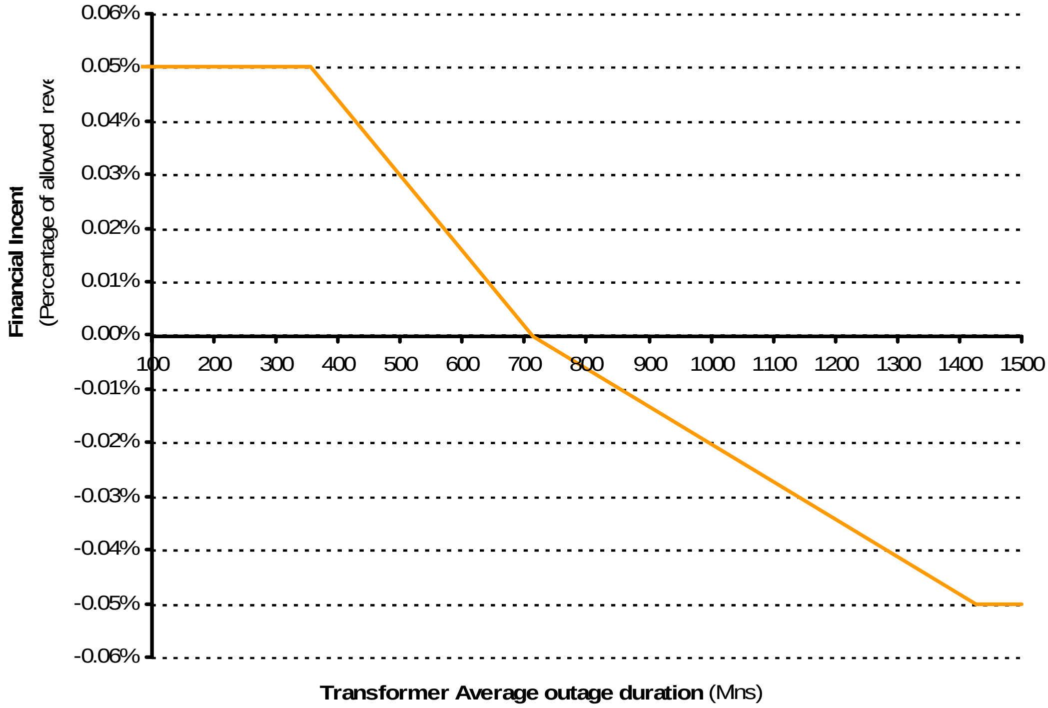

Table G.7: Average outage duration – transformers*

							Where:				
S5	=	–0.000500					1428	<	Average outage duration		
S5	=	–0.000001	x	Average outage duration	+	0.000507	712	≤	Average outage duration	≤	1428
S5	=	–0.000001	x	Average outage duration	+	0.000604	354	≤	Average outage duration	≤	712
S5	=	0.000500							Average outage duration	<	354

* Please note Transend has no revenue at risk against this measure. The 5% measure presented above is purely for illustrative purposes.