Final decision

New South Wales distribution determination 2009–10 to 2013–14

28 April 2009

AUSTRALIAN ENERGY REGULATOR

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Shortened forms

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
capex	capital expenditure
Country Energy’s regulatory proposal	Country Energy, *Country Energy’s Electricity Network Regulatory Proposal 2009-2014*, 2 June 2008
Country Energy’s revised regulatory proposal	Country Energy, *Country Energy’s Electricity Network Revised Regulatory Proposal 2009-2014*, 16 January 2009
CPI	consumer price index
current regulatory control period	1 July 2004 to 30 June 2009
DNSP	distribution network service provider
draft decision	AER, *Draft decision, NSW draft distribution determination, 2009–10 to 2013–14*, November 2008
draft determinations	collectively, AER, *Country Energy draft distribution determination 2009–10 to 2013–14*, November 2008; AER, *EnergyAustralia draft distribution determination 2009–10 to 2013–14*, November 2008; AER, *Integral Energy draft distribution determination 2009–10 to 2013–14*, November 2008
EnergyAustralia’s regulatory proposal	EnergyAustralia, *Regulatory Proposal*, June 2008
EnergyAustralia’s revised regulatory proposal	EnergyAustralia, *Revised Regulatory Proposal and Interim Submission*, January 2009
Final decision	AER, Final *decision, NSW draft distribution determination, 2009–10 to 2013–14*, April 2009
Integral Energy’s regulatory proposal	Integral Energy, *Regulatory Proposal to the Australian Energy Regulator 2009 to 2014, Delivering efficient and sustainable network services*, 2 June 2008
Integral Energy’s revised regulatory proposal	Integral Energy, *Revised Regulatory Proposal to the Australian Energy Regulator 2009 to 2014, Delivering efficient and sustainable network services*, 14 January 2009
IPART	Independent Pricing and Regulatory Tribunal
NEL	National Electricity Law
NEM	national electricity market
NEMMCO	National Electricity Market Management Company
NER	National Electricity Rules
next regulatory control period	1 July 2009 to 30 June 2014
NSW DNSPs	Country Energy, Integral Energy and EnergyAustralia
opex	operating expenditure
transitional chapter 6 rules	transitional provisions set out in appendix 1 of the NER
Wilson Cook	Wilson Cook and Co. Limited

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Overview

A transition to a new regulatory framework

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

The AER's distribution determinations for the period from 1 July 2009 to 30 June 2014 (the next regulatory control period) apply to Country Energy, EnergyAustralia and Integral Energy (the NSW DNSPs). The distribution determinations are made under transitional provisions set out in appendix 1 of the NER (the transitional chapter 6 rules) which incorporates key aspects of the new general chapter 6 rules, but also locks in certain aspects of the current distribution determination made by the NSW regulator, the Independent Pricing and Regulatory Tribunal (IPART).

Review process

In making its distribution determinations, the AER assessed the NSW DNSPs' regulatory proposals to determine if they were in accordance with the requirements of the transitional chapter 6 rules. Expert engineering consultants, as well as financial and economic experts assisted the AER in making its assessment.

The AER released its draft decision and draft determinations for the NSW DNSPs in November 2008. The NSW DNSPs submitted revised regulatory proposals in January 2009 indicating where they did not agree with the draft decision.

The AER also released a supplementary draft decision for alternative control (public lighting) services for the NSW DNSPs in March 2009.

The AER received submissions from a total of 41 interested parties on the draft decision, supplementary draft decision and draft distribution determinations, and the NSW DNSPs' revised regulatory proposals. The majority of interested parties provided submissions in relation to public lighting. The AER's consideration of these submissions forms part of this final decision.

In this final decision the AER specifically addresses those aspects of the draft decision which have not been accepted in a NSW DNSP's revised regulatory proposal or in a submission by another party. Where an aspect of the draft decision was not addressed in a revised regulatory proposal or submissions, then the determination made in the draft decision is confirmed in this final decision.

The AER's examination of the NSW DNSP's revised regulatory proposals was informed by further advice from Wilson Cook and Co. Limited (Wilson Cook). Wilson Cook is an engineering and management consultancy firm, and has considerable experience in reviewing the performance and operating requirements of the NSW DNSPs.

In its draft decision the AER confirmed the need for substantial increases in capital works for each of the NSW DNSPs over the next regulatory control period. Among other reasons, increases in capital works are needed to augment the networks to accommodate the growth in maximum demand for energy, to replace ageing assets and to improve network security and reliability.

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

- Country Energy's proposed capex is $163 million ($2008–09) greater than an efficient level. The AER's draft determination amounts to a 4.1 per cent reduction in the proposed capex

- EnergyAustralia's proposed capex is $465 million ($2008–09) greater than an efficient level. The AER's draft determination amounts to a 5.6 per cent reduction in the proposed capital expenditure

- Integral Energy's proposed capex is $13 million ($2008–09) greater than an efficient level. The AER's draft determination amounts to a 0.5 per cent reduction in the proposed capex.

This final decision approves a capex allowance of $14.4 billion ($2008–09) for the NSW DNSPs, a 6.0 per cent decrease from the draft decision. The reduction in the approved capex allowance in part reflects the impact of slower economic growth and an expected slowing in the growth of maximum demand. After considering the information in the revised regulatory proposals, and taking account of advice from its consultants, the AER has approved EnergyAustralia's revised zone substation capex and Country Energy's revised non–system land and buildings capex. Updated material and labour cost escalators, to reflect the latest available information, are also included in this final decision.

In the draft decision, the AER reduced Country Energy's forecast operating expenditure (opex) proposal to $1975 million ($2008–09), EnergyAustralia's forecast opex proposal was reduced to $2638 million ($2008–09) and Integral Energy's forecast opex proposal was reduced to $1460 million ($2008–09). In response to matters raised in the draft decision, Country Energy, EnergyAustralia and Integral Energy revised their forecast opex proposals to $2211 million, $2991 million and $1521 million ($2008–09) respectively.

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

- Country Energy's opex allowance for the next regulatory control period is to be set at $2052 million ($2008–09), representing a reduction of 7.2 per cent on the total amount proposed

- EnergyAustralia's opex allowance for the next regulatory control period is to be set at $2628 million ($2008–09), representing a reduction of 12.1 per cent on the total amount proposed

- Integral Energy's opex allowance for the next regulatory control period is to be set at $1516 million ($2008–09), representing a reduction of 0.3 per cent on the total amount proposed. The AER has not reduced Integral Energy's controllable opex components and notes its actions to improve productivity during the next regulatory control period.

Although the application of updated lower cost escalators reduces the opex allowance, when compared with the draft decision, the net increase to Country Energy's forecast opex allowance is largely driven by the inclusion of certain vegetation management costs that were not accepted in the draft decision.

The net reduction to EnergyAustralia's forecast opex allowance, when compared with the draft decision, is largely driven by lower labour cost escalators.

The increase to Integral Energy's forecast opex allowance is largely driven by the removal of previously anticipated superannuation cost reductions made in the opex forecast.

Outcome of regulatory process

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

An outcome of the AER's determinations will be higher prices for electricity consumers in NSW. The price increase in 2009–10, however, has been constrained in recognition of the weaker economic outlook. Price increases in subsequent years will compensate the NSW DNSPs for revenue foregone in 2009–10. Prices in 2013–14 have been set to broadly match the expected efficient costs incurred by the businesses.

The increase in network charges is not uniform across the NSW DNSPs. This reflects the specific circumstances faced by each of the NSW DNSPs, which are discussed in this final decision. As a consequence of this final decision, the average retail customer's annual electricity bill in 2009–10 is likely to increase by:

- $1.50 per week for customers connected to Country Energy's network
- $1.49 per week for customers connected to EnergyAustralia's network
- $1.41 per week for customers connected to Integral Energy's network.

The increase in network charges is less than that proposed in the draft decision. The reduction in the expected growth rate of network charges reflects the impact of slower growth in input costs and the decline in the yield on the 10–year Commonwealth Government bond rate compared to the rates and assumptions used in the draft decision. Under the transitional chapter 6 rules the 10–year Commonwealth Government bond yield provides the basis for establishing the NSW DNSPs' cost of capital. The bond yield in the March 2009 reference period was 4.25 per cent compared with 5.46 per cent at the time of the draft decision.

Summary

The AER assumed responsibility for regulating electricity distribution services provided by the NSW DNSPs from 1 January 2008. The distribution determinations for the next regulatory control period are the first for the NSW DNSPs to be conducted by the AER under the NER.

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

This final decision on the NSW DNSPs' distribution determinations should be read in conjunction with the draft decision on the distribution determinations, 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 classification of services that will apply to the NSW DNSPs for the next regulatory control period
- the arrangements for negotiation including those components of direct control services which are to be classified as negotiable components, the negotiable component criteria (NCC), NSW DNSPs' negotiating frameworks and the negotiated distribution service criteria (NDSC)
- the control mechanism for standard control services provided by the NSW DNSPs
- the opening regulatory asset base (RAB) values for the NSW DNSPs
- an assessment of the NSW DNSPs' demand forecasts for the next regulatory control period
- an allowance for forecast capex for the NSW DNSPs over the next regulatory control period
- an allowance for forecast opex for the NSW DNSPs over the next regulatory control period
- an assessment of the NSW DNSPs' estimated corporate income tax and updated tax asset bases
- a decision on the NSW DNSPs' depreciation schedules
- an estimate of the efficient benchmark weighted average cost of capital (WACC) for the NSW DNSPs for the next regulatory control period
- a decision on the service target performance incentive arrangements to apply to the NSW DNSPs for the next regulatory control period
- a decision on the application of the efficiency benefit sharing scheme (EBSS) to the NSW DNSPs in the next regulatory control period
- a decision on the demand management incentive scheme (DMIS) to apply to the NSW DNSPs in the next regulatory control period
- the nominated pass through events that may apply to the NSW DNSPs for the next regulatory control period

- the annual revenue requirements and X factors for the NSW DNSPs for each regulatory year of the next regulatory control period
- the control mechanism for alternative control services provided by the NSW DNSPs
- a decision on EnergyAustralia's proposed pricing methodology.

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

Classification of services

AER draft decision

The draft decision implemented the deemed classification of services for the NSW DNSPs.

The AER did not accept EnergyAustralia's proposal that customer specific services and emergency recoverable works are not distribution services. The AER also did not accept EnergyAustralia's proposed reclassification of metering services (types 1–4), customer funded connections, customer specific services and emergency recoverable works.

The AER specified procedures for the NSW DNSPs to follow when assigning or reassigning customers to tariff classes.

Revised regulatory proposals

Country Energy

Country Energy did not seek revisions to the draft decision.

EnergyAustralia

EnergyAustralia did not accept the draft decision on the classification of its services and resubmitted its original proposal. EnergyAustralia accepted the draft decision to reject an additional miscellaneous service of disconnection at the meter box via fuse removal.

Integral Energy

Integral Energy accepted the draft decision with the exception of the assignment of customers to tariff classes.

Integral Energy noted that there is an inconsistency between the assignment of customers to tariffs and the methodology for calculating reasonable estimates. Integral Energy submitted that if the assignment of customers is deemed reasonable at the time the weighted average price cap calculation is approved, then the assignment should be allowed to proceed.

AER conclusion

The AER does not accept EnergyAustralia's proposal that customer specific services and emergency recoverable works are not distribution services. The AER does not accept EnergyAustralia's proposal to reclassify metering services (types 1–4), customer funded connections, customer specific services and emergency recoverable works as unclassified services.

The AER will implement the deemed classification of services for the NSW DNSPs as provided for in clause 6.2.3B of the transitional chapter 6 rules.

The following classification of services will apply to the NSW DNSPs for the next regulatory control period:

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

Arrangements for negotiation

AER draft decision

The AER defined a negotiable component of a direct control service as any component of a direct control service (or the terms and conditions on which that direct control service or component are provided) in certain circumstances.

The AER's NCC for the NSW DNSPs were set out at appendix B of the draft decision.

The AER approved the NSW DNSPs' negotiating frameworks to apply for the next regulatory control period.

The AER's negotiated distribution service criteria (NDSC) for EnergyAustralia was set out at appendix C of the draft decision.

Revised regulatory proposals

Country Energy and Integral Energy accepted the arrangements for negotiation set out in the draft decision.

EnergyAustralia did not accept the definition of a negotiable component of a direct control service as set out in the draft decision. EnergyAustralia resubmitted its definition of a negotiable component as part of its revised regulatory proposal.

EnergyAustralia submitted that, as a minimum, if the AER continues with the use of its proposed definition it should clarify what is excluded from ‘connection services’. EnergyAustralia also stated that it is not clear how public lighting is to be treated under the definition in the draft decision.

EnergyAustralia did not accept the draft decision to reject most of the issues raised by EnergyAustralia in its submission on the proposed NDSC and NCC.

AER conclusion

The AER has defined a negotiable component of a direct control service as any component of a direct control service (including the terms and conditions on which that direct control service or component is provided) where:

(a) the direct control service exceeds the network performance requirements which the direct control service is required to meet under any jurisdictional electricity legislation

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

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

but excludes in relation to any component of a direct control service:

(d) requirements imposed under a regulatory instrument (other than this final decision and the final determination)

(e) a component of monopoly services as defined in this final decision

(f) a component of miscellaneous services or emergency recoverable works as defined in this final decision (other than a component which is the price or charge for that service where the price or charge is below (but not above) the price or charge set out in this final decision for that service)

(g) a price or charge for the alternative control service of the construction and maintenance of public lighting infrastructure which is above the price or charge set out in this final decision for that service.

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

This approach will apply to Country Energy even though it proposed to not have any negotiable components of direct control services.

The NCC for the NSW DNSPs is set out in appendix B of this final decision.

EnergyAustralia's negotiated transmission services are the only services which are deemed to be negotiated distribution services in the transitional chapter 6 rules. The NDSC for EnergyAustralia is set out in appendix C of this final decision.

The AER approves the NSW DNSPs proposed negotiating frameworks to apply for the next regulatory control period. The negotiating frameworks for Country Energy, EnergyAustralia and Integral Energy are in appendices D, E and F respectively of this final decision.

Control mechanisms for direct control services

AER draft decision

In the draft decision, the AER decided to apply a weighted average price cap (WAPC) to the NSW DNSPs' standard control services for the next regulatory control period.

The AER also decided to apply a schedule of prices for miscellaneous and monopoly services (including emergency recoverable works) for the next regulatory control period.

The AER decided to apply a revenue cap to EnergyAustralia's prescribed (transmission) standard control services.

Revised regulatory proposals

Country Energy

Country Energy did not raise any issues in its revised regulatory proposal regarding the control mechanism.

EnergyAustralia

EnergyAustralia's revised regulatory proposal raised issues relating to:

- the introduction of a G factor to the WAPC formula to reflect uncertainties in energy forecasts caused by the possible introduction of a Carbon Pollution Reduction Scheme (CPRS)
- the pricing of miscellaneous, monopoly services and emergency recoverable works
- the application of side constraints
- the treatment of TUOS (transmission use of system) recoveries.

Integral Energy

Integral Energy's revised regulatory proposal raised two matters with respect to the control mechanism for standard control services:

- the application of the reasonable estimates approach in relation to the introduction of new time of use (ToU) tariff structures

- the introduction of feed–in tariffs by the NSW Government.

AER conclusion

The AER has decided to apply a WAPC to the NSW DNSPs' standard control services. The AER has made a minor amendment to the WAPC formula to explicitly account for any approved cost pass throughs. It has also clarified the side constraint formula that was contained in the draft decision. The formulas for the WAPC and the side constraint are set out at section 4.6 of this final decision.

The AER has decided to apply a schedule of prices for miscellaneous and monopoly services (including emergency recoverable works) for the next regulatory control period. Compared to the draft decision, the prices for these services reflect the addition of a labour cost escalator. The schedule of prices is set out at appendix H to this final decision.

The AER has decided to apply a revenue cap to EnergyAustralia's prescribed (transmission) standard control services. The formula for the revenue cap is set out in section 4.6 of this final decision.

The AER rejected any further changes to the control mechanisms for the other matters raised by EnergyAustralia and Integral Energy in their revised regulatory proposals.

Opening regulatory asset base

AER draft decision

Country Energy

The AER determined Country Energy's opening RAB to be $4247 million for the next regulatory control period (as at 1 July 2009). The AER decided that the opening RAB should not include omitted assets as proposed by Country Energy. Accordingly, the proposed amount of $296 million was not included in the opening RAB as at 1 July 2009.

EnergyAustralia

The AER determined EnergyAustralia's distribution opening RAB to be $7203 million, and its transmission opening RAB to be $985 million for the next regulatory control period (as at 1 July 2009). The combined distribution and transmission opening RAB as at 1 July 2009 was $8188 million.

Integral Energy

The AER determined Integral Energy's opening RAB to be $3678 million for the next regulatory control period (as at 1 July 2009). The AER decided not to approve Integral Energy's proposed increase to the opening RAB of $170 million for asset lives used in the historical valuation of sub–transmission and zone substations.

Capex and CPI data

The AER noted it will update the roll forward of the NSW DNSPs' RAB with actual capex for 2007–08, the most recent forecast of capex for 2008–09, and the latest actual consumer price index (CPI) data at a time closer to its final distribution determination.

Establishing the opening RAB for the 2014–19 regulatory control period

The AER also stated it would use actual depreciation to establish the opening RAB for the 2014–19 regulatory control period.

Revised regulatory proposals

Country Energy

Country Energy accepted the AER draft decision and provided an updated value of actual capex for 2007–08.

EnergyAustralia

EnergyAustralia accepted some aspects of the draft decision but it did not accept other aspects, namely:

- the AER's method of calculating inflation
- the use of actual rather than forecast depreciation in establishing the opening RAB for the 2014–19 regulatory control period.

EnergyAustralia provided an updated value of actual capex for 2007–08. EnergyAustralia also replaced the estimate of inflation for 2007–08 in its regulatory proposal with actual inflation, and updated the inflation estimate used for 2008–09 with the latest available CPI data based on its proposed method.

Integral Energy

Integral Energy accepted the AER's adjustments to the RAB, with the exception of the decision not to include $170 million of assets from its opening RAB from an earlier regulatory control period. Integral Energy also provided an updated value of actual capex for 2007–08.

AER conclusion

Country Energy

To take into account the updated capex and CPI data, the AER has amended its draft decision and determined Country Energy's opening RAB for the next regulatory control period to be $4319 million (as at 1 July 2009). The RAB roll forward calculations are set out in table 1.

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

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	2439.0	2639.0	2921.1	3325.5	3742.4
Actual net capex (adjusted for actual CPI and WACC)[c]	276.7	366.7	473.2	537.9	649.0
CPI adjustment on opening RAB	57.2	70.4	103.4	77.6	162.9
Straight–line depreciation (adjusted for actual CPI)	–133.9	–155.0	–172.2	–198.6	–226.1
Closing RAB	2639.0	2921.1	3325.5	3742.4	4328.2
Adjustment for difference between actual and forecast capex for 2003–04					–5.4
Adjustment for return on difference[d]					–3.4
Opening RAB at 1 July 2009					4319.4

(a) Updated for actual 2007–08 capex.
(b) Updated for actual CPI for 2008–09 (sum of four quarters to December).
(c) The capex values include a half WACC allowance to compensate for the average six–month period before capex is added to the RAB for revenue modelling purposes. The cash values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $5.4 million for 1 July 2003 to 30 June 2004.

EnergyAustralia

To take into account the updated capex and amended CPI data, the AER has amended its draft decision and determined EnergyAustralia's opening RAB (comprising distribution and transmission) for the next regulatory control period to be $8326 million (as at 1 July 2009). The RAB roll forward calculations are set out in tables 2 and 3, and provide for a distribution opening RAB of $7297 million (as at 1 July 2009), and a transmission opening RAB of $1028 million (as at 1 July 2009).

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

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	4064.0	4428.9	4916.0	5627.0	6357.6
Actual net capex (adjusted for actual CPI and WACC)[c]	432.7	549.9	740.5	833.0	934.3
CPI adjustment on opening RAB	95.2	118.2	174.0	131.2	276.7
Straight–line depreciation (adjusted for actual CPI)	–163.1	–181.0	–203.4	–233.7	–269.1
Closing RAB	4428.9	4916.0	5627.0	6357.6	7299.5
Adjustment for difference between actual and forecast capex for 2003–04					27.1
Adjustment for return on difference[d]					17.1
Adjustment for system assets moving from distribution to transmission					–57.8
Adjustment for non–system asset re-allocation					11.2
Opening RAB at 1 July 2009					7297.2

(a) Updated for actual 2007–08 capex.
(b) Updated for actual CPI for 2008–09 (sum of four quarters to December).
(c) The capex values include a half WACC allowance to compensate for the average six–month period before capex is added to the RAB for revenue modelling purposes. The cash values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $27.1 million for 1 July 2003 to 30 June 2004.

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

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	635.6	663.0	698.9	725.7	830.4
Actual net capex (adjusted for actual CPI and WACC)[c]	39.0	44.7	40.8	107.0	167.5
CPI adjustment on opening RAB	15.0	19.8	17.0	30.8	20.5
Straight–line depreciation (adjusted for actual CPI)	–26.7	–28.6	–31.0	–33.1	–36.5
Closing RAB	663.0	698.9	725.7	830.4	981.9
Adjustment for system assets moving to transmission from distribution					57.8
Adjustment for non–system asset re-allocation					–11.2
Opening RAB at 1 July 2009					1028.5

(a) Updated for actual 2007–08 capex.
(b) Updated for actual CPI for 2008–09 (March to March).
(c) The capex values include a half WACC allowance to compensate for the average six–month period before capex is added to the RAB for revenue modelling purposes. The accounting book values for disposal of assets have been deducted.

Integral Energy

To take into account the updated capex and CPI data, the AER has amended its draft decision and has determined Integral Energy's opening RAB for the next regulatory control period to be $3690 million (as at 1 July 2009). The RAB roll forward calculations are set out in table 4.

Integral Energy's opening RAB has not been adjusted to include $170 million of assets which Integral Energy claimed were undervalued in the 1999–04 regulatory control period.

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

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	2283.5	2454.7	2707.6	3021.3	3280.6
Actual net capex (adjusted for actual CPI and WACC)[c]	248.5	330.0	376.1	365.6	555.3
CPI adjustment on opening RAB	53.5	65.5	95.8	70.5	142.8
Straight-line depreciation (adjusted for actual CPI)	–130.8	–142.6	–158.1	–176.8	–193.6
Closing RAB	2454.7	2707.6	3021.3	3280.6	3785.0
Adjustment for difference between actual and forecast capex for 2003–04					–58.3
Adjustment for return on difference[d]					–36.7
Opening RAB at 1 July 2009					3690.0

(a) Updated for actual 2007–08 capex.
(b) Updated for actual CPI for 2008–09 (sum of four quarters to December).
(c) The capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. The accounting book values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $58.3 million for 1 July 2003 to 30 June 2004.

Establishing the opening RAB for the 2014–19 regulatory control period

The AER will use actual depreciation for establishing the opening RABs for the NSW DNSPs for the commencement of the 2014–19 regulatory control period.

Demand forecasts

AER draft decision

The AER stated that Country Energy and EnergyAustralia's maximum demand forecasts set out in their regulatory proposals, provided a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the transitional chapter 6 rules. Integral Energy's revised maximum demand forecast, submitted on 29 August 2008, provided a realistic expectation of forecast demand, as required to achieve the capex and opex objectives in the transitional chapter 6 rules.

The AER considered that EnergyAustralia and Integral Energy's revised customer number forecasts (provided to the AER on 29 and 31 October 2008, respectively) and Country Energy's June 2008 customer number forecasts were appropriate inputs into the post–tax revenue model (PTRM).

The AER stated that, while EnergyAustralia and Integral Energy's energy forecast methodologies were reasonable, the revised forecasts (provided to the AER on 29 and 31 October 2008, respectively) needed to be updated again to take into account the most recent energy sales data for regulatory year 2007–08, for consideration in the final decision. The AER considered Country Energy's energy forecasts were reasonable and requested Country Energy update its forecasts to take into account the most recent energy sales data, for consideration in the final decision.

Revised regulatory proposals

Country Energy

Country Energy provided revised global maximum demand forecasts, accounting for the changed economic outlook and the impact of the proposed Carbon Pollution Reduction Scheme (CPRS) following the release of the Australian Government's December 2008 White Paper. The revised global forecasts were calculated using the same methodology used to generate Country Energy's original June 2008 global maximum demand forecasts.

Country Energy provided a revised customer number forecast, using actual customer numbers as at June 2008 as a starting point and grown at the National Institute of Economic and Industry Research's (NIEIR) updated average annual growth rate for the next regulatory control period. This revised forecast was also updated to take into account the impact of the global economic downturn resulting from the global financial crisis. As a result, Country Energy has forecast new customer connections to grow by an average of 1.3 per cent per annum over the next regulatory control period, compared to its June 2008 forecast of 1.5 per cent per annum.

Country Energy also provided a revised energy forecast based on audited energy sales data for 2007–08. This revised forecast incorporated 2007–08 WAPC data, grown according to NIEIR's updated forecast of average annual energy growth for Country Energy's region. The revised forecast took into account NIEIR's reassessment of the impact of the CPRS and its updated economic outlook.

EnergyAustralia

EnergyAustralia provided a revised global maximum demand forecast, taking into account the impact of the worsening global financial crisis, the timing and magnitude of price increases resulting from the CPRS, a number of newly introduced NSW Government levies and the draft decision. In revising its global maximum demand forecasts it maintained the same methodology used to generate its June 2008 forecast.

EnergyAustralia stated that it considered there was too much uncertainty over the timing and magnitude of the forecast economic recovery in NSW for it to further update its customer number forecast from that provided to the AER on 29 October 2008.

EnergyAustralia provided a revised energy forecast using updated data and inputs and incorporating some changes recommended by the AER's consultant, McLennan Magasanik Associates (MMA), in its report on EnergyAustralia's energy forecast methodology. The revised forecast took into account the impact on demand of anticipated electricity price rises, as well as the impact of the worsening global financial crisis.

Integral Energy

Integral Energy did not provide a revised maximum demand forecast in its revised regulatory proposal. However, it revised its capex proposal to incorporate its top–down assessment of the impact of the worsening global financial crisis on maximum demand.

Integral Energy provided a revised customer number forecast, incorporating audited 2007–08 sales data and an updated NIEIR gross state product (GSP) forecast for its region, which took into account the worsening global financial crisis and the impact of the CPRS White Paper.

Integral Energy provided a revised energy forecast, also incorporating audited energy sales data for 2007–08 and the updated NIEIR GSP forecast for its region. Aside from these updates, Integral Energy substantially retained the methodology used to generate its October 2008 revised energy forecast.

AER conclusion

Country Energy

The AER considers the revised global maximum demand forecasts provided by Country Energy in its revised regulatory proposal are reasonable, but notes that the forecasts have limited application for the AER's assessment of the revised capex proposal as they were not prepared on a spatial basis.

The AER considers that the revised customer number and energy forecasts as set out in table 5 and provided by Country Energy on 24 February 2009 are appropriate inputs to the PTRM.

Table 5: Country Energy's customer number and energy forecasts for 2009–14

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14[a]
Customer number forecast	1 321 286	1 339 074	1 357 118	1 375 421	1 393 989	1.3%
Energy forecast (GWh)	12 092	12 147	12 202	12 556	12 314	0.5%

(a) Average annual growth includes growth from year 2008–09.

EnergyAustralia

The AER considers that the revised global maximum demand forecasts provided by EnergyAustralia in its revised regulatory proposal are reasonable, but notes that the forecasts have limited application for the AER's assessment of the revised capex proposal as they were not prepared on a spatial basis.

The AER maintains its draft decision that EnergyAustralia's customer number forecast, set out in table 6 and provided to the AER on 29 October 2008 is an appropriate input to the PTRM.

The AER considers that the revised energy forecast provided to the AER by EnergyAustralia on 9 April 2009, which was generated according to the AER's conclusions, is an appropriate input to the PTRM. This revised forecast is set out in table 6.

Table 6: EnergyAustralia's customer number and energy forecasts for 2009–14[a]

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14[b]
Customer number forecast	2 073 691	2 087 691	2 102 703	2 117 640	2 132 584	0.6%
Energy forecast (GWh)	27 948	28 041	27 989	27 673	27 477	–0.1%

(a) Figures in table 6 exclude some large customer loads.
(b) Average annual growth includes growth from year 2008–09.

Integral Energy

Integral Energy did not provide a revised maximum demand forecast in its revised regulatory proposal. Integral Energy provided a revised capex proposal given the worsening global financial crisis was likely to reduce its required growth capex for the next regulatory control period. The AER's consideration of the adjustments made to Integral Energy's capex proposal to account for changes in maximum demand resulting from the worsening global financial crisis are set out in chapter 7.

The AER considers that the revised customer number and energy forecasts as set out in table 7 and provided by Integral Energy in its revised regulatory proposal are appropriate inputs into the PTRM.

Table 7: Integral Energy's customer number and energy forecasts for 2009–14[a]

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14[b]
Customer number forecast	860 392	866 018	873 565	885 078	896 496	1%
Energy forecast (GWh)	17 373	17 313	17 526	17 967	18 202	0.7%

(a) The AER notes that the figures in table 7 exclude controlled loads.
(b) Average annual growth includes growth from year 2008–09.

Forecast capital expenditure

AER draft decision

Country Energy

The AER considered that Country Energy's forecast capex allowance of $4008 million ($2008–2009) did not satisfy the capex criteria in the transitional chapter 6 rules. The AER applied a reduction of $53 million ($2008–09) to Country Energy's proposed forecast capex, and approved an allowance for Country Energy of $3955 million ($2008–2009).

EnergyAustralia

The AER considered that EnergyAustralia's forecast capex allowance of $8659 million ($2008–2009) did not satisfy the capex criteria in the transitional chapter 6 rules. The AER applied a reduction of $224 million ($2008–09) to EnergyAustralia's proposed forecast capex, and approved a total capex allowance for EnergyAustralia (distribution and transmission) of $8435 million ($2008–2009).

Integral Energy

The AER considered that Integral Energy's forecast capex allowance of $2953 million ($2008–2009) did not satisfy the capex criteria in the transitional chapter 6 rules. The AER applied a reduction of $39 million ($2008–09) to Integral Energy's proposed forecast capex, and approved an allowance for Integral Energy of $2914 million ($2008–2009).

Revised regulatory proposals

Country Energy

Country Energy's revised regulatory proposal included a capex allowance of $4047 million ($2008–09) for the next regulatory control period.

Country Energy implemented the draft decision in respect of forecast capex, except those related to non–system IT expenditure, real cost escalators and adjustments to non–system land and buildings expenditure.

Following submission of its revised regulatory proposal, Country Energy further reviewed its growth capex forecasts in light of the revised demand forecasts, and submitted a revised proposed capex allowance of $3989 million. The revised proposed capex allowance was approximately $19 million lower than its original capex proposal.

EnergyAustralia

EnergyAustralia's revised regulatory proposal included a total capex allowance for distribution and transmission of $8303 million ($2008–09) for the next regulatory control period (excluding equity raising costs). The revised proposed capex allowance was approximately $356 million lower than its original capex proposal.

EnergyAustralia revised its capex allowance to include revised peak demand forecasts that reflected EnergyAustralia's estimate of the impact of the CPRS and lower economic growth forecasts.

EnergyAustralia implemented the draft decision but did not implement the decision to reject the 'black spot' network reliability program and zone substation expenditure.

Integral Energy

Integral Energy's revised regulatory proposal included a capex allowance of $2735 million ($2008–09) for the next regulatory control period. The revised proposed capex proposal was approximately $218 million lower than its original capex proposal.

Integral Energy revised its forecast capex down by $244 million due to the global financial crisis. This revision included a reduction of $173 million due to the deferral of major projects, and a reduction of $70 million due to revised customer connection forecasts.

Integral Energy implemented the draft decision in respect of forecast capex, except those related to the substation renewal projects, real cost escalators and the application of inflation.

AER conclusion

The AER is not satisfied that the proposed forecast capex allowances of each NSW DNSP reasonably reflect the efficient costs, or a realistic expectation of the demand forecast and cost inputs a prudent operator in the circumstances of each NSW DNSP would require to achieve the capex objectives as provided for in the capex criteria under clause 6.5.7(c) of the transitional chapter 6 rules.

As the AER is not satisfied that the proposed capex allowances reasonably reflect the capex criteria, the AER has decided not to accept them. The AER is therefore required to provide an estimate of the required capex for each NSW DNSP over the next regulatory control period that it is satisfied reasonably reflects the capex criteria, including the capex objectives.

Country Energy

Following its review of Country Energy's revised capex proposal the AER has made the following adjustments:

- $12 million reduction for incorrectly capitalised tap changer and relay setting works
- $32 million reduction to non–system IT expenditure
- $119 million reduction to reflect the application of modified input cost escalators to its capex program as determined in appendix L of this final decision.

The AER considers that a forecast capex allowance that reflects the efficient costs that a prudent operator in the circumstances of Country Energy would require to satisfy the capex objectives at clause 6.5.7(a) of the transitional chapter 6 rules and capex criteria at 6.5.7(c) of the transitional chapter 6 rules is $3826 million.

The AER's conclusion for Country Energy's capex for the next regulatory control period is set out in table 8.

Table 8: AER conclusion on Country Energy's capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER draft decision	742.6	776.8	799.9	809.3	826.7	3955.4
Country Energy proposed capex	743.4	792.6	813.7	811.0	828.7	3989.3
Adjustment for IT expenditure	–3.0	–6.0	–6.0	–6.1	–10.7	–31.8
Adjustment for relay setting and tap changers	–2.4	–2.4	–2.4	–2.4	–2.5	–12.1
Adjustment for cost escalators	–22.4	–26.7	–28.8	–23.3	–18.3	–119.5
Capex allowance	715.7	757.5	776.5	779.1	797.2	3826.0

Note: Totals may not add up due to rounding.

EnergyAustralia

Following its review of EnergyAustralia's revised capex proposal the AER has made the following adjustments:

- $15 million reduction to the 'black spot' reliability program
- $28 million reduction for tariff based demand management
- $421 million reduction to reflect the application of modified input cost escalators to its capex program as determined in appendix L of this final decision.

The AER considers that a forecast capex allowance that reflects the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to satisfy the capex objectives at clause 6.5.7(a) and capex criteria at 6.5.7(c) is $7838 million.

The AER's conclusion for EnergyAustralia's capex for the next regulatory control period is set out in tables 9 and 10.

Table 9: AER conclusion on EnergyAustralia's distribution capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER draft decision	1300.0	1401.8	1563.1	1433.4	1459.6	7157.9
EnergyAustralia proposed capex	1292.7	1398.4	1501.8	1420.2	1437.3	7050.4
Adjustment to 'black spot' reliability project	–3.0	–3.1	–3.1	–3.1	–3.1	–15.4
Adjustment for tariff based demand management	–	–	–	–	–25.4	–25.4
Adjustment for cost escalators	–157.5	–113.7	–76.5	–40.2	14.5	–373.3
Adjustment for transmission/distribution allocation (non–system)	0.5	0.3	0.2	0.2	0.2	1.4
Capex allowance	1132.7	1281.7	1422.2	1377.1	1423.3	6637.7

Note: Totals may not add up due to rounding.

Table 10: AER conclusion on EnergyAustralia's transmission capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER draft decision	264.0	178.9	264.9	339.7	229.3	1276.8
Total EnergyAustralia proposed capex	271.9	180.4	256.6	336.0	207.7	1252.6
Adjustment for tariff based demand management	–	–	–	–	–2.5	–2.5
Adjustment for cost escalators	–7.7	–6.0	–11.1	–15.4	–8.0	–48.1
Adjustment for transmission/distribution allocation (non–system)	–0.5	–0.3	–0.2	–0.2	–0.2	–1.4
Capex allowance	263.7	174.2	245.3	320.4	197.0	1200.5

Note: Totals may not add up due to rounding.

Integral Energy

Following its review of Integral Energy's revised capex proposal the AER has made the following adjustments:

- $15 million reduction to substation renewal projects
- $2.0 million increase to reflect the application of modified input cost escalators to its capex program as determined in appendix L of this final decision.

The AER considers that a forecast capex allowance that reflects the efficient costs that a prudent operator in the circumstances of Integral Energy would require to satisfy the capex objectives at clause 6.5.7(a) of the transitional chapter 6 rules and capex criteria at 6.5.7(c) of the transitional chapter 6 rules is $2721 million.

The AER's conclusion for Integral Energy's capex for the next regulatory control period is set out in table 11.

Table 11: AER conclusion on Integral Energy's capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER draft decision	571.9	638.0	606.3	575.5	521.9	2913.7
Integral Energy proposed capex	567.5	616.2	550.9	501.8	498.5	2734.9
Adjustments arising from replacement capex	0.0	0.0	0.0	0.0	–15.4	–15.4
Adjustment for cost escalators	3.2	2.5	–0.1	–0.9	–2.8	2.0
Capex allowance	570.7	618.7	550.9	500.9	480.3	2721.4

Note: Totals may not add up due to rounding.

Forecast operating expenditure

AER draft decision

Country Energy

The AER considered that Country Energy's proposed forecast total opex allowance of $2160 million ($2008–09) did not reasonably reflect the opex criteria in the transitional chapter 6 rules. The AER applied a reduction of $185 million ($2008–09) or approximately 9 per cent to Country Energy's proposed forecast opex and approved an allowance of $1975 million ($2008–09).

EnergyAustralia

The AER considered that EnergyAustralia's proposed forecast total opex allowance of $3047 million ($2008–09) did not reasonably reflect the opex criteria in the transitional chapter 6 rules. The AER applied a reduction of $410 million ($2008–09) or approximately 13 per cent to EnergyAustralia's proposed opex forecast and approved an allowance of $2638 million ($2008–09).

Integral Energy

The AER considered Integral Energy's proposed forecast total opex allowance of $1477 million ($2008–09) did not reasonably reflect the opex criteria in the transitional chapter 6 rules. The AER applied a reduction of $17 million ($2008–09) or approximately 1 per cent to Integral Energy's proposed forecast opex and approved an allowance of $1460 million ($2008–09).

Revised regulatory proposals

Country Energy

Country Energy implemented the draft decision in respect of forecast opex except those aspects related to:

- network maintenance costs adjustment
- costs for review of voltage regulation relay settings and distribution transformer tap positions
- vegetation management asset growth escalation
- costs relating to the outcomes of a specific legal decision involving Country Energy
- self insurance costs
- debt raising costs
- equity raising costs
- certain cost escalators.

Country Energy's revised forecast opex allowance for the next regulatory control period was $2211 million ($2008–09).

EnergyAustralia

In the draft decision, the AER reduced EnergyAustralia's original opex proposal by $23 million following further analysis by EnergyAustralia regarding the relationship between capex and maintenance expenditure and errors identified by EnergyAustralia in its asset age profile information. In its revised regulatory proposal, EnergyAustralia accepted these adjustments.

EnergyAustralia rejected all the reductions the AER made in its draft decision to EnergyAustralia's adjusted opex proposal. In particular, EnergyAustralia rejected the reductions of:

- $214 million for network operating costs
- $31 million for network maintenance costs
- $83 million for other operating costs
- other non–controllable opex—self insurance costs and debt and equity raising costs totalling $82 million.

EnergyAustralia proposed a revised total opex allowance of $2991 million ($2008–09), a reduction of $80 million from its regulatory proposal and $353 million greater than the amount of opex allowed by the AER in its draft decision. EnergyAustralia accepted the AER's capitalisation of equity raising costs in the draft decision, but not the amount.

Integral Energy

Integral Energy implemented the draft decision in respect of forecast opex except those aspects related to:

- real labour cost escalators
- defined benefit adjustment to superannuation
- self insurance costs
- debt raising costs
- equity raising costs.

Integral Energy's revised forecast opex allowance for the next regulatory control period was $1521 million ($2008–09).

AER conclusion

Country Energy

The AER considered that Country Energy's revised forecast total opex of $2211 million ($2008–09) did not reasonably reflect the opex criteria under clause 6.5.6(c) of the transitional chapter 6 rules, including the opex objectives.

The AER applied a reduction of $159 million to Country Energy's revised proposed opex. This represents a reduction of around 7.2 per cent of Country Energy's proposed opex of $2211 million and results in an amended forecast opex allowance of $2052 million. This amended estimate represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives, as required by clause 6.5.6(c)(2) of the transitional chapter 6 rules.

The AER's conclusion on Country Energy's total forecast opex allowance is set out in table 12.

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

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy's revised controllable opex forecast	402.8	423.6	435.7	447.1	457.5	2166.7
Self insurance costs	3.9	3.9	3.9	3.9	3.9	19.5
Debt raising costs	4.0	4.5	5.0	5.5	6.1	25.0
Equity raising costs	–	–	–	–	–	–
Country Energy's total opex	410.7	432.0	444.6	456.5	467.4	2211.2
AER's controllable opex	389.9	397.8	405.3	411.8	416.2	2021.1
Self insurance costs	3.0	3.0	3.0	3.0	3.0	15.0
Debt raising costs	2.1	2.3	2.6	2.8	3.1	12.9
Equity raising costs[a]	–	–	–	–	–	–
Demand management innovation allowance[b]	0.6	0.6	0.6	0.6	0.6	3.0
AER's total opex	395.6	403.7	411.5	418.2	422.9	2052.0

Note: Totals may not add up due to rounding.
(a) The AER will allow Country Energy to amortise a total of $16.8 million ($2008–09) for benchmark equity raising costs associated with forecast capex for the next regulatory control period.
(b) Refer to chapter 14 for details on this allowance.

EnergyAustralia

The AER considered that EnergyAustralia's revised forecast total opex of $2991 million ($2008–09) did not reasonably reflect the opex criteria under clause 6.5.6(c) of the transitional chapter 6 rules, including the opex objectives.

The AER applied a reduction of $363 million to EnergyAustralia's revised proposed opex. This represents a reduction of around 12 per cent of EnergyAustralia's proposed opex of $2991 million and results in an amended forecast opex allowance of $2628 million. This amended estimate represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives, as required by clause 6.5.6(c)(2) of the transitional chapter 6 rules.

The AER's conclusion on EnergyAustralia's total forecast opex allowance is set out in table 13.

Table 13: AER conclusion on EnergyAustralia's total forecast opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia's revised controllable opex forecast	548.8	566.9	582.8	601.6	610.8	2910.9
Self insurance costs	5.9	5.9	5.9	5.9	5.9	29.6
Debt raising costs	7.6	9.0	10.1	11.4	12.6	50.8
Equity raising costs	–	–	–	–	–	–
EnergyAustralia's total opex	562.4	581.8	598.9	618.9	629.3	2991.3
AER's controllable opex	497.4	507.4	517.8	526.9	527.7	2577.3
Self insurance costs	4.1	4.1	4.1	4.1	4.1	20.6
Debt raising costs	3.9	4.5	5.0	5.6	6.2	25.2
Equity raising costs[a]	–	–	–	–	–	–
Demand management innovation allowance[b]	1.0	1.0	1.0	1.0	1.0	5.0
AER's total opex	506.5	517.0	527.9	537.7	539.0	2628.1

Note: Totals may not add up due to rounding.
(a) The AER will allow EnergyAustralia to amortise a total of $38.0 million ($2008–09) for benchmark equity raising costs associated with forecast capex for the next regulatory control period.
(b) Refer to chapter 14 for details on this allowance.

Integral Energy

The AER considered that Integral Energy's revised forecast total opex of $1521 million ($2008–09) did not reasonably reflect the opex criteria under clause 6.5.6(c) of the transitional chapter 6 rules, including the opex objectives.

The AER applied a reduction of $4.3 million to Integral Energy's revised proposed opex. This represents a reduction of around 0.3 per cent of Integral Energy's proposed opex of $1521 million and results in an amended forecast opex allowance of $1516 million. This amended estimate represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of Integral Energy would require to achieve the opex objectives, as required by clause 6.5.6(c)(2) of the transitional chapter 6 rules.

The AER's conclusion on Integral Energy's total forecast opex allowance is set out in table 14.

Table 14: AER conclusion on Integral Energy's total forecast opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Integral Energy's revised controllable opex forecast	289.6	291.0	296.5	302.7	303.8	1483.7
Self insurance costs	3.1	3.2	3.3	3.3	3.2	16.1
Debt raising costs	3.5	3.9	4.3	4.6	4.8	21.1
Equity raising costs	–	–	–	–	–	–
Integral Energy's total opex	296.3	298.1	304.0	310.5	311.9	1520.8
AER's controllable opex	293.2	295.4	299.7	303.3	301.9	1493.4
Self insurance costs	1.9	1.9	1.9	1.9	1.9	9.6
Debt raising costs	1.8	1.9	2.1	2.3	2.4	10.5
Equity raising costs[a]	–	–	–	–	–	–
Demand management innovation allowance[b]	0.6	0.6	0.6	0.6	0.6	3.0
AER's total opex	297.4	299.8	304.3	308.1	306.9	1516.5

Note: Totals may not add up due to rounding.
(a) The AER will allow Integral Energy to amortise a total of $9.4 million ($2008–09) for benchmark equity raising costs associated with forecast capex for the next regulatory control period.
(b) Refer to chapter 14 for details on this allowance.

Estimated corporate income tax

AER draft decision

The AER determined that each of the inputs proposed by the NSW DNSPs that have been used in the PTRM to calculate the expected cost of corporate income tax is in accordance with the transitional chapter 6 rules. The AER considered that each of the NSW DNSP's proposed tax remaining and tax standard lives were appropriate. The AER also considered each of the NSW DNSP's proposed opening tax asset bases to be appropriate and reasonable.

Revised regulatory proposals

Each NSW DNSP submitted a revised allowance for corporate income tax in their respective revised regulatory proposal. For each NSW DNSP, the method used to calculate the income tax allowance was consistent with the draft decision. However, each NSW DNSP's proposed tax asset base was updated to include 2007–08 actuals for capex and tax depreciation rather than estimates.

On 19 February 2009, Integral Energy provided a revised estimate of its tax asset base which included $170 million for omitted assets.

AER conclusion

The AER considers the following tax asset bases appropriate and reasonable:

- Country Energy – $2699 million ($nominal)
- EnergyAustralia – $4997 million ($nominal)
- Integral Energy – $2435 million ($nominal).

The tax asset bases above are consistent with Country Energy and EnergyAustralia's revised regulatory proposals while Integral Energy's proposed tax asset base was updated to account for work in progress. However, the AER rejects the further revision to the tax asset base proposed by Integral Energy for the inclusion of omitted assets.

The AER also considers that Country Energy's proposed tax remaining and tax standard lives are appropriate. The AER considers EnergyAustralia's proposed tax standard lives (as corrected) and tax depreciation methodology appropriate in the circumstances. The AER considers that Integral Energy's revised tax standard and tax remaining lives provided on 19 February 2009 are appropriate and reasonable once the remaining life for the substations asset class is adjusted to exclude omitted assets.

On the basis of these inputs, the AER has used the PTRM to calculate the allowance for corporate income tax as set out in table 15.

Table 15: AER conclusion on the NSW DNSPs'corporate income tax allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	43.9	46.5	39.2	45.6	50.1	225.4
EnergyAustralia	34.0	64.6	73.7	84.0	88.0	344.4
Integral Energy	34.9	38.4	38.1	37.3	37.5	186.2

Depreciation

AER draft decision

As a result of adjustments to the asset class life inputs to the PTRM for each NSW DNSP, the AER considered that the NSW DNSPs' proposed depreciation schedules did not comply with the transitional chapter 6 rules, and therefore the AER did not approve them.

Revised regulatory proposals

The NSW DNSPs' proposed revised regulatory depreciation schedules in response to the draft decision reflecting changes to asset class life inputs.

Country Energy

Country Energy accepted and implemented all aspects of the draft decision. It re–allocated the value of the 'work in progress' asset category across other asset classes to derive appropriate remaining asset lives for each asset class.

EnergyAustralia

EnergyAustralia accepted the draft decision and adjusted the standard asset life of the ‘cable tunnel (dx)’ asset class in its revised regulatory proposal PTRM to correct for an input error identified in the draft decision.

Integral Energy

Integral Energy accepted the draft decision. Integral Energy re–allocated the value of the ‘work in progress’ asset category across other asset classes. However, it did not update the estimated remaining life of each asset class to reflect this.

Integral Energy also proposed a standard asset life of 38.5 years for the equity raising costs asset class, which it determined using a weighted average of the standard asset lives of both system and non–system assets. This differed from the 43.2 year standard asset life determined in the draft decision using a weighted average of the standard asset lives of system assets alone.

AER conclusion

As a result of required adjustments to the NSW DNSPs’ opening RABs and capex allowances (as discussed in chapters 5 and 7 respectively), the AER has not approved the depreciation schedules proposed by the NSW DNSPs’ in their revised regulatory proposals.

On the basis of the approved asset lives, opening RAB and forecast capex allowances, the AER has determined depreciation schedules for the NSW DNSPs. The depreciation schedules have resulted in regulatory depreciation allowances for the NSW DNSPs, for the next regulatory control period as set out in table 16.

Table 16: AER conclusion on the NSW DNSPs’ regulatory depreciation allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	154.1	176.7	141.5	161.1	180.8	814.3
EnergyAustralia	80.0	106.9	131.0	156.6	151.8	626.2
Integral Energy	144.3	123.2	119.7	113.4	106.1	606.7

Cost of capital

AER draft decision

The AER determined a nominal vanilla WACC of 9.72 per cent for each of the NSW DNSPs. The AER stated it would update the WACC for changes to 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.

Revised regulatory proposals

The NSW DNSPs revised regulatory proposals adopted a nominal vanilla WACC different to that determined in the draft decision. In estimating the WACC for their revised regulatory proposals, the NSW DNSPs adopted a different averaging period for the risk–free rate and debt risk premium. Country Energy and EnergyAustralia also rejected the use of just Bloomberg data to estimate the debt risk premium.

The NSW DNSPs implemented the AER's inflation forecast of 2.55 per cent in their revised regulatory proposals. However, they proposed that, if the AER did not accept the averaging period for the nominal risk–free rate proposed in their revised regulatory proposals, then the AER should reconsider its inflation estimate.

AER conclusion

The AER has determined a nominal vanilla WACC for each of the NSW DNSPs as set out in table 21. The WACC for each NSW DNSP is based on an updated risk–free rate and debt risk premium, and other parameters prescribed in the transitional chapter 6 rules. The AER's WACC is lower than the WACC proposed by each of the NSW DNSPs in their revised regulatory proposals because of a lower nominal risk–free rate—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 periods in the NSW DNSPs' regulatory proposals is reasonable and that the agreed averaging periods are consistent with finance theory, regulatory practice, the NER and the NEL. The AER considers that the material provided by the NSW DNSPs in support of their revised regulatory proposals does not justify that an averaging period prior to 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.

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, consistent with the draft decision, this methodology provides the best estimate of a 10–year inflation forecast to be applied in the post–tax revenue model for this final decision. The AER's conclusion on WACC parameters is set out in table 17.

Table 17: AER conclusion on WACC parameters

Parameter	Country Energy	EnergyAustralia	Integral Energy
Risk–free rate (nominal)	4.29%	4.29%	4.32%
Risk–free rate (real)[a]	1.78%	1.78%	1.80%
Expected inflation rate	2.47%	2.47%	2.47%
Debt risk premium	3.48%	3.48%	3.52%
Market risk premium	6.00%	6.00%	6.00%
Gearing	60%	60%	60%
Equity beta	1.00	1.00	1.00
Nominal pre–tax return on debt	7.78%	7.78%	7.84%
Nominal post–tax return on equity	10.29%	10.29%	10.32%
Nominal vanilla WACC	8.78%	8.78%	8.83%

(a) The real risk–free rate was calculated using the Fisher equation.

Service target performance incentive arrangements

AER draft decision

The AER decided it would collect and monitor the NSW DNSPs' service performance data during the next regulatory control period. It also decided that revenue would not be placed at risk under the data collection process during this period.

In consultation with the NSW DNSPs, the AER developed service performance data reporting requirements for the next regulatory control period. The data reporting requirements were aligned with the requirements of the national distribution service target performance incentive scheme (STPIS).

The AER stated that it expected the NSW DNSPs to implement measures to achieve full compliance with the national distribution STPIS as soon as practical.

Revised regulatory proposals

Country Energy

Country Energy agreed that the service performance reporting requirements should be aligned with the national distribution STPIS, however, it was concerned about its ability to have systems implemented and tested by December 2009.

Country Energy restated that it is unlikely to be able to provide full momentary average interruption frequency index (MAIFI) data for the next regulatory control period. Country Energy further submitted that the definition of the AER's frequency of interruption parameter requires further clarification, stating that the current definition is unworkable in Country Energy's distribution area.

Country Energy also stated that the publication of two sets of data has the potential to confuse users.

EnergyAustralia

EnergyAustralia restated its position that the STPIS reporting arrangements should use definitions, methods and exclusions consistent with those in the NSW distribution licence conditions. EnergyAustralia did not provide an estimate of the additional costs associated with reporting against the national distribution STPIS, however, it submitted that some work would be required.

EnergyAustralia stated that the AER has not provided sufficient evidence or analysis to demonstrate the benefits to customers from consistency in national standards.

Integral Energy

Integral Energy broadly supported the AER's proposal to collect and monitor service performance data during the next regulatory control period, based on a generally applicable national scheme. It submitted that it will actively participate in the STPIS data collection exercise. Integral Energy stated that the reporting framework for the STPIS and the NSW licence conditions should be aligned so that only one reporting regime is required.

AER conclusion

The AER maintains its draft decision to collect and monitor service performance data during the next regulatory control period. Revenue will not be placed at risk under the data collection process during this period.

The AER acknowledges that the NSW DNSPs may not achieve full compliance with the data reporting requirements before December 2009. However, the AER expects the NSW DNSPs to implement measures to achieve full compliance with the national distribution STPIS as soon as practical.

Efficiency benefit sharing scheme

AER draft decision

The AER stated it will apply the EBSS released in February 2008 to the NSW DNSPs for the next regulatory control period and outlined the opex cost categories to be excluded from the operation of the EBSS for the next regulatory control period.

Revised regulatory proposals

Country Energy did not seek to add further exclusions to the scheme.

EnergyAustralia did not comment on the draft decision regarding the application of the EBSS.

Integral Energy proposed that the EBSS be adjusted where there is a movement of costs between capex and opex during the regulatory control period. Integral Energy also proposed that symmetrical uncontrollable costs, and specifically costs relating to defined benefit superannuation liabilities, should be included in the operation of the EBSS.

AER conclusion

The AER will apply the EBSS released in February 2008 to the NSW DNSPs for the next regulatory control period. The AER will not adjust the EBSS for the consequences of changes in demand growth for the next regulatory control period.

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

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

The forecast controllable opex for each of the NSW DNSPs is outlined in tables 18 to 20 and will be used to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS

Table 18: AER conclusion on Country Energy's forecast controllable opex for EBSS purposes ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total forecast opex	395.6	403.7	411.5	418.2	422.9	2052.0
Adjustment for debt raising costs	2.1	2.3	2.6	2.8	3.1	12.9
Adjustment for self insurance	3.0	3.0	3.0	3.0	3.0	15.0
Adjustment for insurance	5.6	5.7	5.8	6.0	6.2	29.3
Adjustment for superannuation	20.9	21.0	21.7	22.7	23.7	110.0
Adjustment for non–network alternatives	0.6	0.6	0.6	0.6	0.6	3.0
Forecast opex for EBSS purposes	363.4	371.1	377.8	383.2	386.4	1881.8

Note: Totals may not add up due to rounding.

Table 19: AER conclusion on EnergyAustralia's forecast controllable opex for EBSS purposes ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total forecast opex	506.5	517.0	527.9	537.7	539.0	2628.1
Adjustment for debt raising costs	3.9	4.5	5.0	5.6	6.2	25.2
Adjustment for self insurance	4.1	4.1	4.1	4.1	4.1	20.6
Adjustment for insurance	6.1	6.1	6.1	6.1	6.1	30.4
Adjustment for superannuation	–	–	–	–	–	–
Adjustment for non–network alternatives	4.9	4.9	5.0	5.0	5.0	24.8
Forecast opex for EBSS purposes	487.5	497.4	507.8	516.9	517.6	2527.1

Note: Totals may not add up due to rounding.

Table 20: AER conclusion on Integral Energy's forecast controllable opex for EBSS purposes ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total forecast opex	297.4	299.8	304.3	308.1	306.9	1516.5
Adjustment for debt raising costs	1.8	1.9	2.1	2.3	2.4	10.5
Adjustment for self insurance	1.9	1.9	1.9	1.9	1.9	9.6
Adjustment for insurance	6.2	6.2	6.2	6.2	6.2	31.0
Adjustment for superannuation	–	–	–	–	–	–
Adjustment for non–network alternatives	2.1	2.2	2.2	2.2	2.2	10.9
Forecast opex for EBSS purposes	285.5	287.6	291.9	295.5	294.1	1454.6

Note: Totals may not add up due to rounding.

Demand management incentives

AER draft decision

The AER decided to apply the D–factor scheme to the NSW DNSPs over the next regulatory control period, in the form applied by IPART over the current regulatory control period.

The draft decision, subject to the agreement of the NSW DNSPs, amended the demand management innovation allowance (DMIA) published on 29 February 2008, by replacing it with the DMIA specified in the AER's *Demand management incentive scheme for the ACT and NSW distribution determinations*, (the replacement DMIA). The replacement DMIA was published concurrently with the draft decision.

Revised regulatory proposals

Country Energy

Country Energy considered that the replacement DMIA was an improvement on the original DMIA, and subsequent to submitting its revised regulatory proposal, provided its agreement to amend the original scheme by applying the replacement DMIA. However, Country Energy submitted that the DMIA needed to be increased to promote meaningful demand management, and suggested that an amount between 1 per cent and 5 per cent of annual revenue requirements would be fair and reasonable.

EnergyAustralia

EnergyAustralia restated its argument that foregone revenues associated with demand management projects carried out in the current regulatory control period should be recovered under the D–factor during the next regulatory control period.

EnergyAustralia stated that it considered the replacement DMIA was a reasonable approach to the issues raised in its regulatory proposal, and provided its agreement for the application of the replacement DMIA over the next regulatory control period subsequent to submitting its revised regulatory proposal. However, EnergyAustralia also requested that the allowance be increased.

Integral Energy

Integral Energy stated that it generally supported the AER's approach to the DMIA, and subsequent to submitting its revised regulatory proposal, Integral Energy agreed to the application of the replacement DMIA for the next regulatory control period. However, Integral Energy maintained its position that the allowance should be increased to be in line with EnergyAustralia's allowance of $1 million per annum.

AER conclusion

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

The AER maintains its draft decision to apply the replacement DMIA to the NSW DNSPs in the next regulatory control period.

Pass through arrangements

AER draft decision

In the draft decision the AER accepted a retail project event and force majeure event as nominated pass through events for the NSW DNSPs. The AER did not consider that the other proposed pass through events met the AER's assessment criteria and therefore it did not accept those events as nominated pass through events. The AER did not define a materiality threshold for pass through events.

Revised regulatory proposals

Country Energy

Country Energy only accepted some aspects of the draft decision. Country Energy proposed in its revised regulatory proposal that the following events be nominated as pass through events:

- changes in risk assessment costs due to court cases and other legal obligations
- certain events the AER had suggested would be regulatory change events, specifically:
  - the introduction of smart meters
  - retailer of last resort
  - the introduction of an emissions trading scheme
- electric and magnetic field uninsurable events
- earthquakes greater than magnitude five
- an insurance event.

EnergyAustralia

EnergyAustralia did not accept any aspect of the draft decision with respect to pass through events. EnergyAustralia maintained the position in its regulatory proposal (submitted in June 2008), and proposed the following seven events to be nominated as pass through events:

- separation event
- customer connection event
- compliance event
- joint planning event
- cost or demand input variance event
- force majeure event
- dead zone event.

Integral Energy

Integral Energy only accepted some aspects of the draft decision. Integral Energy proposed in its revised regulatory proposal that the following events be nominated as pass through events:

- automated interval meter event
- change in reporting requirements event
- distribution loss event
- electric and magnetic fields event
- emissions trading scheme event

- functional change event
- retailer of last resort event
- insurance event.

AER conclusion

The AER has decided to nominate two types of nominated pass through events:

- specific nominated pass through events to cover certain foreseeable events that can easily be defined
- general nominated pass through events to cover unforeseeable changes in circumstances falling outside of the normal operations of the NSW DNSPs' business.

The AER has decided to nominate the following specific nominated pass through events for the NSW DNSPs:

- a retail project event
- a smart meter event
- an emissions trading scheme event.

The AER also nominates an aviation hazards event as a specific nominated pass through event for Country Energy.

Definitions of these events are set out in section 15.5.3 of this final decision.

The AER has decided not to nominate the other events proposed by the NSW DNSPs as specific nominated pass through events.

Revenue requirements

AER draft decision

X factors

In the draft decision the AER noted that each of the NSW DNSPs had proposed large X factors and associated price increases, particularly for 2009–10. The AER reduced the size of the X factors to be applied in 2009–10 by each NSW DNSP.

Revenue requirements

Country Energy

The AER's draft decision resulted in a total revenue requirement over the next regulatory control period of $5819 million ($nominal), compared to $5978 million proposed by Country Energy. The difference reflected:

- a $196 million ($nominal) reduction to opex
- a $68.4 million ($nominal) increase in the regulatory depreciation building block reflecting changes to standard life assumptions
- a $34.8 million ($nominal) reduction to the return on capital.

EnergyAustralia

The draft decision resulted in the total revenue requirement over the next regulatory control period of $994 million ($nominal) for transmission and $8453 million ($nominal) for distribution, compared to $1040 million and $8969 million respectively proposed by EnergyAustralia. The difference in the combined revenue requirements mainly reflected:

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

Integral Energy

The AER's draft decision resulted in a total revenue requirement over the next regulatory control period of $4632 million ($nominal), compared to $4695 million proposed by Integral Energy. The difference reflected:

- removal of the $170 million ($nominal) from Integral Energy's opening RAB
- reductions to capex and opex due to the application of revised real cost escalations.

Revised regulatory proposals

Country Energy

Country Energy's revised regulatory proposal proposed a total revenue requirement over the next regulatory control period of $6278 million ($nominal), which was $460 million more than the draft decision.

EnergyAustralia

EnergyAustralia's revised regulatory proposal included a total revenue requirement over the next regulatory control period for both its transmission and distribution business of $10 235 million ($nominal), which is $787 million more than the draft decision.

Integral Energy

Integral Energy's revised regulatory proposal included a total revenue requirement over the next regulatory control period of $4916 million ($nominal), which is $284 million more than the draft decision.

AER conclusion

Country Energy

The total revenue requirement for Country Energy over the next regulatory control period is $5672 million ($nominal) as set out in table 21, compared to $6278 million proposed by Country Energy. The main reasons for this difference reflect:

- the $179 million ($nominal) reduction to opex
- a $428 million ($nominal) reduction to the return on capital, reflecting the AER's final decision on Country Energy's WACC.

Table 21: AER conclusion on Country Energy's revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		154.1	176.7	141.5	161.1	180.8
Return on capital		379.4	433.0	488.6	550.9	613.6
Tax allowance		43.9	46.5	39.2	45.6	50.1
Operating expenditure		405.4	424.0	442.8	461.2	477.9
TUOS adjustment		–44.9				
Annual revenue requirements		937.9	1080.2	1112.2	1218.9	1322.4
Expected revenues	732.3	856.8	1000.0	1153.0	1329.7	1370.4
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–13.41	–13.31	–12.00	–12.00	0.00

(a) Negative values for X indicate real price increases under the CPI–X formula.

EnergyAustralia

The total revenue requirement for EnergyAustralia over the next regulatory control period is $943 million ($nominal) for transmission and $7843 million ($nominal) for distribution as set out in tables 22 and 23, compared to $1117 million and $9118 million respectively proposed by EnergyAustralia. This reflects an overall difference of $1449 million in nominal revenue requirements for the combined transmission and distribution business, and is mainly comprised of:

- a $401 million ($nominal) reduction to opex
- a $1037 million ($nominal) reduction to the return on capital, reflecting the AER's final decision to apply a WACC of 8.78 per cent, compared to EnergyAustralia's proposed WACC of 10.16 per cent.

Table 22: AER conclusion on EnergyAustralia's revenue requirements and X factors – distribution ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		76.0	99.5	120.1	142.3	138.4
Return on capital		640.9	740.7	852.6	977.6	1098.9
Tax allowance		31.5	58.4	66.5	75.5	78.9
Operating expenditure		483.1	506.4	530.8	554.6	570.6
Annual revenue requirements		1231.4	1404.9	1570.0	1750.1	1886.7
Expected revenues	1023.5	1224.3	1382.7	1562.7	1758.7	1924.6
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–17.86	–12.00	–12.00	–12.00	–8.00

(a) Negative values for X indicate real price increases under the CPI–X formula.

Table 23: AER conclusion on EnergyAustralia's revenue requirements and X factors – transmission ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		4.0	7.4	10.9	14.2	13.5
Return on capital		90.3	114.9	130.7	153.3	183.6
Tax allowance		2.6	6.2	7.2	8.5	9.2
Operating expenditure		35.9	36.5	37.3	38.3	38.5
Annual revenue requirements		132.8	165.0	186.2	214.4	244.7
Expected revenues	129.5	143.0	162.6	185.0	210.4	239.3
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–7.77	–11.00	–11.00	–11.00	–11.00

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

Integral Energy

The total revenue requirement for Integral Energy over the next regulatory control period is $4485 million ($nominal) as set out in table 24, compared with $4916 million proposed by Integral Energy. The main reasons for this difference reflect:

- removal of the $170 million ($nominal) from Integral Energy's opening RAB, affecting mainly the depreciation and return on capital building blocks

- a $339 million ($nominal) reduction to the return on capital, which largely reflects the AER's decision to apply a WACC of 8.83 per cent, compared to Integral Energy's proposed WACC of 10.02 per cent.

Table 24: AER conclusion on Integral Energy's revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		144.3	123.2	119.7	113.4	106.1
Return on capital		326.0	366.5	413.9	456.4	495.8
Tax allowance		34.9	38.4	38.1	37.3	37.5
Operating expenditure		304.8	314.8	327.4	339.7	346.8
Annual revenue requirements		809.9	843.0	899.2	946.8	986.1
Expected revenues	652.8	749.9	828.4	919.0	984.8	1024.3
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–12.58	–7.00	–7.00	–2.00	0.00

(a) Negative values for X indicate real price increases under the CPI–X formula.

Alternative control (public lighting) services

In the AER's *Statement on control mechanisms for alternative control services for the ACT and NSW 2009 distribution determinations*, the AER concluded that public lighting would be subject to a fixed schedule of prices for the first year of the next regulatory control period (based on revenues determined from a limited building block approach) and a price path for the remaining years of the regulatory control period.

AER draft decision

In June 2008, the NSW DNSPs submitted their proposed schedule of fixed prices for public lighting.

In the draft decision, the AER identified a number of issues associated with the charges proposed by the NSW DNSPs. In light of these issues, the AER considered that it was necessary to revise its approach to regulating public lighting. The AER amended the control mechanism for alternative control services to:

- a schedule of fixed prices in the first year of the next regulatory control period for assets constructed before 1 July 2009 developed using a building block approach
- a schedule of fixed prices in the first year of the next regulatory control period for assets constructed after 30 June 2009 developed using an annuity capital charge approach
- a price path, such as CPI, for the remaining years of the next regulatory control period.

The AER required each NSW DNSP to resubmit its proposed charges by 16 January 2009, consistent with the AER's revised approach.

AER supplementary draft decision

Each of the NSW DNSPs provided the AER with prices consistent with the AER's draft decision.

On 16 March 2009 the AER published a supplementary draft decision to allow stakeholders an opportunity to comment on the NSW DNSPs' submissions and the AER's conclusions.

Stakeholders were particularly concerned about the proposed charges for energy efficient lighting. Stakeholders requested the AER to further examine differences in costs between energy efficient lighting with other less efficient lighting types both in NSW and against the charges the AER had endorsed as part of its decision on energy efficient lighting in Victoria.

NSW DNSPs response to the supplementary draft decision

Country Energy

Country Energy supported the principle that gains from productivity improvements should be passed on to consumers in the form of improved services at lower or similar prices. However, it considered that the AER's supplementary draft decision may be based on unrealistic expectations about the extent of achievable cost reductions and questioned the AER's conclusions on the cost of bulk lamp replacement programs, inventory management and the capital costs of new assets.

EnergyAustralia

EnergyAustralia considered that the AER based its rejection of its annuity model methodology for assets constructed before 1 July 2009 on the fact that it objected to an input used in the methodology (that is, the use of replacement cost for assets instead of depreciated historical costs) rather than an objection to the methodology itself, which the AER accepts for assets constructed after 30 June 2009.

EnergyAustralia submitted that if the AER refuses to approve a methodology, value or amount, the substitute must be determined on the basis of the current regulatory proposal and amended from that basis only to the extent necessary to enable it to be approved in accordance with the rules. EnergyAustralia submitted that the AER had exceeded its permitted discretion by rejecting the model rather than addressing the input in the model.

Integral Energy

Integral Energy supported the AER's consultative approach to developing public lighting charges.

Integral Energy sought clarification on a number of the AER's assumptions that differed from Integral Energy's submission in response to the AER's draft decision. Integral Energy also reiterated its position on the WACC and the labour content of operating costs and stressed that the AER's fixed price path should be expressed in real terms with a CPI adjustment being added each year.

AER conclusion

In light of the submissions made by EnergyAustralia, the AER has reviewed its application of the building block approach to assets constructed before 1 July 2009. The AER considers that its building block approach better meets the national electricity objective than EnergyAustralia's annuity approach for reasons discussed in this final decision. The AER also considers that it has correctly exercised its discretion in requiring EnergyAustralia to use a limited building block model to calculate a schedule of fixed charges and price path for assets constructed before 1 July 2009.

The AER recognises the concerns raised by stakeholders regarding the prices of energy efficient lighting as opposed to other lighting types. The AER has examined these charges and has made every effort to disaggregate costs according to their asset type and for charges to be as cost reflective as possible.

Under the AER's approach to smoothing charges for assets constructed before 1 July 2009, some customers will experience initial increases in charges for 2009–10. However, the majority of customers should experience initial decreases in charges in 2009–10 and will continue to experience real annual decreases over the next regulatory control period under the AER's price path.

For Country Energy, the AER expects annual changes in charges for individual customers of between 1.5 per cent and 3.9 per cent per annum in nominal terms. For EnergyAustralia, annual changes in customer charges are expected between –9.5 per cent and 1.1 per cent per annum and for Integral Energy between –4.0 per cent and 3.6 per cent per annum.

For assets constructed after 30 June 2009, under an annuity approach the prices developed are fixed maximum prices in that they remain constant for the life of the asset and will be increased by inflation on an annual basis.

The AER is also cognisant of the fact that the provision of public lighting has been defined as an alternative control service, with the potential for the development of competition in this service. Under its decision, the approved charges are maximum prices. The NSW DNSPs would not be prevented from lowering their charges in response to competition from third party market entrants for the supply, installation and maintenance of public lighting assets.

The AER will monitor compliance of the NSW DNSPs with the alternative control service control mechanism an annual basis.

Pricing methodology for EnergyAustralia prescribed (transmission) standard control services

AER draft decision

The AER decided to approve EnergyAustralia's revised proposed pricing methodology, as amended in accordance with the AER's request for clarification of the cost allocation methodology.

EnergyAustralia revised regulatory proposal

EnergyAustralia provided a formal signed copy of its approved pricing methodology in its revised regulatory proposal.

AER conclusion

The AER's decision is to approve EnergyAustralia's pricing methodology. The approved pricing methodology is set out in appendix T of this final decision.

1 Introduction

1.1 Background

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

The AER's principal regulatory task is to set the annual revenue requirement that a DNSP can recover from the provision of direct control services during the five–year regulatory control period.

The AER made the draft decision and draft distribution determinations for Country Energy, EnergyAustralia and Integral Energy (NSW DNSPs) on 21 November 2008.[1] Its draft decision and draft distribution determinations were made in accordance with the relevant transitional provisions within chapter 11 of the NER (the transitional chapter 6 rules). Through its distribution determinations, the AER is required to provide the NSW DNSPs with the opportunity to recover sufficient revenues to meet the efficient costs of providing direct control services and complying with regulatory obligations for the period from 1 July 2009 to 30 June 2014 (the next regulatory control period).

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

On 28 November 2008 the AER published its draft decision and draft distribution determinations for the NSW DNSPs. In mid–January 2009 the NSW DNSPs submitted their revised regulatory proposals in response to the draft decision. The revised regulatory proposals were published by the AER on 19 January 2009.

This final decision should be read in conjunction with the draft decision and draft distribution determinations for the NSW DNSPs published by the AER on 28 November 2008.

1.2 AER draft decision

Key elements of the draft decision and draft distribution determinations were:

- the opening regulatory asset base (RAB) values for the NSW DNSPs
- the AER's assessment of the NSW DNSPs' forecast capital expenditure (capex) programs

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1 AER, *Draft decision, NSW draft distribution determination, 2009–10 to 2013–14*, 21 Nov 2008; AER, *Country Energy draft distribution determination 2009–10 to 2013–14*, 21 Nov 2008; AER, *EnergyAustralia draft distribution determination 2009–10 to 2013–14*, 21 Nov 2008; and AER, *Integral Energy draft distribution determination 2009–10 to 2013–14*, 21 Nov 2008.

- the AER's assessment of the NSW DNSPs' forecast operating expenditure (opex) programs
- an estimate of the efficient benchmark weighted average cost of capital (WACC) for the NSW DNSPs
- the NSW DNSPs' annual revenue requirement for each year of the next regulatory control period
- the AER's decision regarding the NSW DNSPs' proposed negotiating frameworks
- the AER's proposed negotiable component criteria (NCC) that will apply to the NSW DNSPs and the negotiated distribution service criteria (NDSC) that will apply to EnergyAustralia.

Using the parameters defined in the NER, the AER determined a nominal vanilla WACC of 9.72 per cent for the NSW DNSPs. The AER noted in its draft decision that 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 the date of its final distribution determination.

The AER assessed the NSW DNSPs' negotiating frameworks for negotiable components of direct control services and considered that the negotiating frameworks complied with part DA of the transitional chapter 6 rules, and for EnergyAustralia, part D of the transitional chapter 6 rules. The draft decision also specified the NCC for the NSW DNSPs and the NDSC for EnergyAustralia for the next regulatory control period.

The remaining elements of the draft decision and draft distribution determinations are summarised briefly below for each NSW DNSP.

1.2.1 Country Energy

The draft decision provided a total revenue requirement over the next regulatory control period of $5819 million. Table 1.1 shows the annual building block calculations including X factors. The calculations are based on an opening RAB of $4247 million, and a forecast capex allowance of $3955 million for the next regulatory control period.

Table 1.1: AER draft decision on Country Energy's revenue requirements and X factors ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Regulatory depreciation	158.4	169.2	132.7	152.0	172.0	784.3
Return on capital	412.7	473.4	538.2	611.0	685.2	2720.5
Tax allowance	46.2	49.7	43.7	50.9	55.9	246.4
Operating expenditure	369.1	387.2	408.4	475.4	497.4	2137.5
TUOS adjustment	–70.0	–	–	–	–	–70.0
Annual revenue requirements	916.4	1079.6	1123.0	1289.3	1410.4	5818.7
Expected revenues	938.8	1043.3	1159.6	1288.9	1382.2	5812.8
Forecast CPI (%)	2.55	2.55	2.55	2.55	2.55	
X factors (%)	–19.71	–6.80	–6.80	–6.80	–3.00	

1.2.2 EnergyAustralia

The draft decision provided a total revenue requirement over the next regulatory control period of $9448 million. Tables 1.2 and 1.3 show the annual building block calculations including X factors for EnergyAustralia (distribution and transmission, respectively). The calculations are based on an opening distribution RAB of $7203 million, a transmission RAB of $985 million and a total forecast capex allowance of $8435 million over the next regulatory control period.

Table 1.2: AER draft decision on EnergyAustralia's revenue requirements and X factors distribution ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Regulatory depreciation	70.8	94.1	114.6	136.3	131.0	546.8
Return on capital	699.9	828.6	966.4	1121.5	1263.5	4879.9
Tax allowance	36.1	64.3	73.8	84.8	89.6	348.6
Operating expenditure	478.1	504.5	534.7	567.0	594.0	2678.3
Annual revenue requirements	1284.8	1491.5	1689.4	1909.5	2078.2	8453.4
Expected revenues	1284.8	1469.5	1670.4	1886.6	2138.0	8449.3
Forecast CPI (%)	2.55	2.55	2.55	2.55	2.55	
X factors (%)	–24.30	–10.43	–10.43	–10.43	–10.43	

Table 1.3: AER draft decision on EnergyAustralia's revenue requirements and X factors transmission ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Regulatory depreciation	4.8	8.1	11.6	14.9	14.0	53.4
Return on capital	95.7	122.6	140.6	167.8	203.6	730.3
Tax allowance	3.0	6.9	8.0	9.6	10.6	38.1
Operating expenditure	32.8	33.3	34.3	35.6	36.3	172.3
Annual revenue requirements	136.3	170.9	194.6	227.9	264.5	994.2
Expected revenues	137.1	162.9	193.5	229.9	273.1	996.5
Forecast CPI (%)	2.55	2.55	2.55	2.55	2.55	
X factors (%)	–3.26	–15.85	–15.85	–15.85	–15.85	

1.2.3 Integral Energy

The draft decision provided a total revenue requirement for Integral Energy over the next regulatory control period of $4632 million. Table 1.4 shows the annual building block calculations including X factors. The calculations are based on an opening RAB of $3678 million, and a forecast capex allowance of $2914 million over the next regulatory control period.

Table 1.4: AER draft decision on Integral Energy's revenue requirements and X factors ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Regulatory depreciation	137.6	117.0	110.5	102.2	100.4	567.7
Return on capital	357.4	402.1	457.2	511.2	564.2	2292.1
Tax allowance	37.8	39.1	39.3	38.4	41.2	195.8
Operating expenditure	292.2	302.6	314.8	327.7	339.5	1576.8
Annual revenue requirements	825.0	860.8	921.8	979.5	1045.4	4632.5
Expected revenues	792.8	856.0	925.0	996.8	1075.4	4646.0
Forecast CPI (%)	2.55	2.55	2.55	2.55	2.55	
X factors (%)	–15.42	–3.50	–3.50	–3.50	–3.50	

1.3 Revised regulatory proposals

1.3.1 Country Energy

Country Energy submitted its revised regulatory proposal to the AER on 16 January 2009. Country Energy provided revised energy, customer number and global maximum demand forecasts as part of its revised regulatory proposal, taking into account the reduced economic growth outlook arising from the global financial crisis and the impact on demand of changes to the Australian Government's planned Carbon Pollution Reduction Scheme (CPRS).

Country Energy's revised regulatory proposal sets out an annual revenue requirement that increases from $979 million in 2009–10 to $1503 million in 2013–14 ($nominal), and a total revenue requirement of $6279 million for the next regulatory control period.

Country Energy's revised opening RAB was $4262 million (as at 1 July 2009). Country Energy accepted all aspects of the draft decision regarding the opening RAB.

Country Energy's revised capex forecast for the next regulatory control period was $4047 million ($2009–10). It updated estimates of 2007–08 capex using actual capex in that year, and implemented most aspects of the draft decision relating to forecast capex, except those related to:

- non–system IT capex
- non–system land and buildings capex
- cost escalation of non–system capex
- cost escalators.

Country Energy's revised forecast opex for the next regulatory control period was $2212 million ($2008–09). This includes additional opex arising from new obligations flowing from a legal decision impacting Country Energy. It implemented most aspects of the draft decision relating to opex, except those related to:

- network maintenance
- vegetation management
- self insurance costs
- debt raising costs
- equity raising costs
- labour cost escalation.

Country Energy accepted most other elements of the draft decision relating to the classification of services, arrangements for negotiation, control mechanisms, efficiency benefit sharing scheme (EBSS), depreciation and service target performance incentive scheme (STPIS), with the following exceptions:

- charges for miscellaneous services, monopoly services and emergency recoverable works
- some pass through definitions and risk assessments

- demand management innovation allowance (DMIA).

1.3.2 EnergyAustralia

EnergyAustralia submitted its revised regulatory proposal to the AER on 14 January 2009. EnergyAustralia provided revised energy and global maximum demand forecasts as part of its revised regulatory proposal, taking into account a lower economic growth forecast for NSW resulting from the global financial crisis, and anticipating the impact of the CPRS on energy sales. As a result of its revised maximum demand forecast, EnergyAustralia revised its forecast capex.

EnergyAustralia's revised regulatory proposal sets out a total annual revenue requirement that increases from $1548 million in 2009–10 to $2528 million in 2013–14 ($nominal), with a total annual revenue requirement of $10 billion for the next regulatory control period.

EnergyAustralia's revised opening RAB was $8.4 billion (as at 1 July 2009). EnergyAustralia rejected the draft decision regarding the calculation of actual inflation for indexing the opening RAB.

EnergyAustralia's revised capex forecast for the next regulatory control period was $8.5 billion ($2008–09). EnergyAustralia did not implement the following aspects of the draft decision relating to forecast capex:

- substation cost estimates
- black spot reliability program
- external labour and commodities cost escalators.

EnergyAustralia's revised forecast opex for the next regulatory control period is $3.0 billion ($2008–09). It implemented most aspects of the draft decision relating to opex, except those related to:

- step changes in opex costs
- network maintenance costs
- workload increase escalations
- self insurance
- debt raising costs
- equity raising costs.

EnergyAustralia did not accept the draft decision regarding the arrangements for negotiation. EnergyAustralia also revised its proposed control mechanism for standard control services to account for uncertainty in energy forecasts.

EnergyAustralia rejected the draft decision regarding the STPIS reporting requirements.

EnergyAustralia accepted most other elements of the draft decision relating to the classification of services, EBSS, demand management, depreciation and the pricing methodology, with the following exceptions:

- classification of metering services (types 1–4), customer funded connections, customer specific services and emergency recoverable works
- assigning customers to tariff classes
- the treatment of forgone revenue under the D–factor scheme
- the treatment of any unspent DMIA
- the recognition of the time value of money within the DMIA.
- pass through definitions and risk assessments.

1.3.3 Integral Energy

Integral Energy submitted its revised regulatory proposal to the AER on 14 January 2009. Integral Energy provided revised energy and customer number forecasts as part of its revised regulatory proposal, taking into account a reduced economic growth outlook for its region resulting from the worsening global financial crisis. Integral Energy also revised its forecast capex to account for the global financial crisis.

Integral Energy's revised regulatory proposal sets out an annual revenue requirement that increases from $892 million in 2009–10 to $1093 million in 2013–14 ($nominal), with a total annual revenue requirement of $4916 million for the next regulatory control period.

Integral Energy's revised opening RAB was $3810 million (as at 1 July 2009). Integral Energy rejected aspects of the draft decision on the opening RAB relating to the historical valuation of sub–transmission and zone substation assets.

Integral Energy's revised capex forecast for the next regulatory control period was $2735 million ($2009–10). Integral Energy implemented most aspects of the draft decision relating to forecast capex, except those related to:

- substation renewal
- cost escalators.

Integral Energy's revised forecast opex for the next regulatory control period was $1521 million ($2008–09). It implemented most aspects of the draft decision relating to opex, except those related to:

- defined benefit adjustment to superannuation costs
- self insurance costs
- debt raising costs
- equity raising costs
- labour cost escalation.

Integral Energy did not accept the STPIS reporting requirements.

Integral Energy accepted most other elements of the draft decision relating to the classification of services, arrangements for negotiation, control mechanisms, EBSS and depreciation, with the following exceptions:

- some pass through definitions and risk assessments
- superannuation cost inclusion in the EBSS
- capitalisation policy changes and the EBSS
- DMIA allowance.

1.4 Review process

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

- Pre–consultation—the AER consulted with the NSW DNSPs about the development of the regulatory information notice, pro forma templates and guidelines.
- Cost allocation method—in March 2008 the AER assessed and approved cost allocation methods under clause 6.15.6 of the transitional chapter 6 rules.
- Proposal—the NSW DNSPs submitted their regulatory proposals and proposed negotiating frameworks to the AER on 2 June 2008.
- Public consultation—the AER published the NSW DNSPs' regulatory proposals and the AER's proposed negotiable component criteria and proposed negotiated distribution service criteria on 27 June 2008 and called for interested parties to make submissions. The AER held a public forum on the NSW DNSPs' regulatory proposals on 30 July 2008, where each DNSP and interested parties made presentations.
- Submissions—the AER received 41 submissions on the NSW DNSPs' regulatory proposals. The submissions are listed in appendix U of the draft decision.
- Assessment by technical experts—the AER engaged Wilson Cook & Co Limited (Wilson Cook) as a technical expert.
- Assessment by demand forecast experts—the AER engaged McLennan Magasanik Associates (MMA) in relation to demand forecasts.
- Additional technical advice—the AER engaged Energy and Management Services (EMS) to provide the AER with technical and engineering advice throughout the review process.
- Other specialist advice—the AER also engaged Econtech to provide a forecast of ACT and NSW labour costs relevant to electricity distribution businesses.
- Draft decision and draft distribution determinations—on 28 November 2008 the AER published its draft decision and draft distribution determinations.

- Public consultation—on 28 November 2008 the AER called for interested parties to make submissions. The AER held public forums on the draft decision and draft distribution determinations on 8 and 9 December 2008.

- Revised regulatory proposals—the NSW DNSPs submitted their revised regulatory proposals and proposed negotiating frameworks to the AER in mid–January 2009.

- Supplementary draft decision—the AER published a supplementary draft decision regarding alternative control services (public lighting) on 13 March 2009. The supplementary draft decision provided detail on the likely fees and charges the NSW DNSPs would impose under the arrangements set out in the draft decision for alternative control services.

- Submissions—the AER received submissions from a total of 41 interested parties on the draft decision, supplementary draft decision and draft distribution determinations, and the NSW DNSPs' revised regulatory proposals. The submissions are listed in appendix U and V. Several submissions were received by the AER after the closing date for submissions. These submissions are listed in appendix V.

- Assessment by a technical expert—The AER engaged Wilson Cook as a technical expert to review a number of aspects of the NSW DNSPs' revised regulatory proposals. Specifically the AER asked Wilson Cook to provide its opinion on:

  - capex issues:

    - Country Energy—double counting associated with non–system land and buildings, non–system IT capex

    - EnergyAustralia—revised peak demand forecasts, prudence and efficiency of capex associated with the black spot reliability program, zone substation expenditure and changes in demand management initiatives

    - Integral Energy—substation renewal capex

  - opex issues

    - Country Energy—vegetation management growth escalation, compliance expenditure due to the 2007 NSW Court of Appeal case, *Sheather v Country Energy*

    - EnergyAustralia—benchmarking analysis, step change expenditure, efficiency and productivity measures, network maintenance costs, workload escalators.

- Additional specialist advice—The AER engaged Associate Professor John Handley to advise on issues relating to debt and equity raising costs.

- Final decision—The AER made its final decision on the NSW DNSPs' distribution determinations on 28 April 2009.

1.5 Structure of final decision

This final decision sets out the AER's consideration of the NSW DNSPs' revised regulatory proposals, including substantive issues raised in submissions. Except as specified in this final decision, the AER maintains its conclusions set out in the draft decision and the supplementary draft decision. Therefore, this final decision should be read in conjunction with the draft decision published by the AER on 28 November 2008 and the supplementary draft decision published on 13 March 2009.

The AER's consideration of the NSW DNSPs' revised regulatory proposals and proposed negotiating frameworks together with the NCC and the NDSC, is set out as follows:

- chapters 2 to 4 address the classification of services, arrangements for negotiation and control mechanisms for standard control services
- chapters 5 to 11 relate to elements of the building block calculation
- chapters 12 to 15 set out relevant schemes and pass through arrangements
- chapter 16 sets out the annual building block revenue requirements for the next regulatory control period
- chapter 17 sets out the alternative control services control mechanism and the AER's review of alternative control services
- chapter 18 sets out EnergyAustralia's pricing methodology relating to its prescribed (transmission) standard control services.

2 Classification of services

2.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision on the classification of services for NSW DNSPs. It also sets out the AER's decision on the classification of the NSW DNSPs' distribution services for the next regulatory control period and the arrangements for assigning and reassigning customers to tariff classes.

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

2.2 AER draft decision

In the draft decision, the AER decided to implement the deemed classification of services for the NSW DNSPs.[2]

The AER did not accept EnergyAustralia's proposal that customer specific services and emergency recoverable works are not distribution services.[3] The AER also did not accept EnergyAustralia's proposed reclassification of metering services (types 1–4), customer funded connections, customer specific services and emergency recoverable works.[4]

The AER, having regard to the principles in clause 6.18.4, proposed the procedures specified in appendix A of the draft decision, for the NSW DNSPs to follow when assigning or reassigning customers to tariff classes.

2.3 Revised regulatory proposals

Country Energy

Country Energy accepted the draft decision.[5]

EnergyAustralia

EnergyAustralia did not accept the draft decision on the classification of its services and resubmitted its original proposal, with the following comments: [6]

- EnergyAustralia disagreed with the conclusion that it did not provide sufficient information to allow the AER to vary the classification of the services

[2] AER, *Draft decision*, p. 17.
[3] AER, *Draft decision*, p. 18.
[4] AER, *Draft decision*, p. 18.
[5] Country Energy, *Country Energy's electricity network, Revised regulatory proposal 2009–2014*, 16 January 2009, p. 9.
[6] EnergyAustralia, *Revised regulatory proposal and interim submission*, January 2009, pp. 147–152.

- EnergyAustralia stated that the AER did not provide adequate explanations for its decision as required by the NER
- EnergyAustralia submitted that its decision not to apply to IPART to have the services reclassified is irrelevant for the AER's own determination and the AER did not consider the level of regulation actually applied by IPART
- EnergyAustralia did not accept the AER's claim of a strong presumption in favour of not reclassifying services
- EnergyAustralia did not support the AER's reasons for delay in considering the reclassification of services

EnergyAustralia accepted the draft decision regarding the rejection of its proposal for an additional miscellaneous service of disconnection at the meter box via fuse removal.[7]

EnergyAustralia submitted that the AER did not accept or reject any of the points raised in its proposal and did not provide substantive reasons (apart from process) for its decision not to vary the deemed classifications. EnergyAustralia stated that the draft decision failed to consider EnergyAustralia's proposal with respect to the classification of its services. Furthermore, EnergyAustralia stated that adequate reasons—as required by clauses 6.10.2(a)(3), 6.11.2 and 6.12.2 of the transitional chapter 6 rules—were not provided by the AER to explain its draft decision.[8]

EnergyAustralia maintained that it provided a comprehensive proposal in favour of varying the classification of services. EnergyAustralia stated that it had no reason to believe that the AER did not have sufficient information upon which to make a decision.[9]

EnergyAustralia submitted that the question of whether or not customer specific services and emergency recoverable works are distribution services is a matter of legal analysis and not a case for additional analysis.[10]

EnergyAustralia stated that IPART's approach to the consideration of the classification of services is irrelevant to the AER's decision on whether to vary the classification. This is because the AER has an obligation to properly consider EnergyAustralia's proposal within the current regulatory framework of the NEL and the transitional chapter 6 rules. EnergyAustralia noted the AER had not considered the level of regulation actually applied to excluded services by IPART during the current regulatory control period.[11]

EnergyAustralia stated that it does not accept there is a strong presumption that services will follow the deemed classifications unless the DNSP can satisfy the AER that a different classification is clearly more appropriate. It stated that the transitional chapter 6 rules simply provide for the AER to decide to apply a different classification.[12] EnergyAustralia also submitted the AER has not properly assessed whether the

7 EnergyAustralia, *Revised regulatory proposal*, pp. 147–148.
8 EnergyAustralia, *Revised regulatory proposal*, pp. 149–150.
9 EnergyAustralia, *Revised regulatory proposal*, p. 148.
10 EnergyAustralia, *Revised regulatory proposal*, pp. 148–149.
11 EnergyAustralia, *Revised regulatory proposal*, p. 150.
12 EnergyAustralia, *Revised regulatory proposal*, p. 151.

presumption (if any) should be displaced because the AER has not properly considered and engaged with the substance of EnergyAustralia's arguments.[13]

EnergyAustralia submitted that the transitional chapter 6 rules confer a responsibility on the AER to consider the issues involved and it is not acceptable for the AER to defer that consideration due to truncated timelines.[14]

Integral Energy

Integral Energy implemented the findings of the draft decision with the exception of the assignment of customers to tariff classes.[15]

Integral Energy noted that there is an inconsistency between the assignment of customers to tariffs (as outlined in appendix A of the draft decision) and the methodology for calculating reasonable estimates (as detailed in appendix J of the draft decision). This could mean that in calculating prices for a particular year, it is assumed that a customer will be assigned a new tariff, but when the assignment takes place the customer objects and as a result of the process outlined in appendix A of the draft decision, the customer remains on their existing tariff.[16]

Integral Energy submitted that if the assignment of customers is deemed reasonable at the time the weighted average price cap calculation is approved, then the assignment should be allowed to proceed. To do otherwise would mean that the process of reasonable estimates for the weighted average price cap is flawed.[17]

2.4 Submissions

2.4.1 Integral Energy

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

Integral Energy submitted that it has established processes for assigning customers to tariff classes or for reassigning customers from one tariff class to another. This process complies with the principles governing assignment or reassignment of customers to tariff classes outlined in clause 6.18.4 of the transitional chapter 6 rules and aligns with appendix A of the draft decision.[18]

Reassignment of existing customers to another existing tariff during the regulatory control period

Integral Energy submitted that section 5 of appendix A of the draft decision should be modified so that a change in connection characteristics specifically includes the installation of a meter with time of use capabilities in order to enable the reassignment of the customer to a time of use tariff. The process in appendix A of the draft decision does

[13] EnergyAustralia, *Revised regulatory proposal*, p. 151.
[14] EnergyAustralia, *Revised regulatory proposal*, p. 152.
[15] Integral Energy, *Revised regulatory proposal to the AER 2009 to 2014, delivering efficient and sustainable network services*, 14 January 2009, p. 87.
[16] Integral Energy, *Revised regulatory proposal*, p. 88.
[17] Integral Energy, *Revised regulatory proposal*, p. 88.
[18] Integral Energy, *Submission to the Australian Energy Regulator 2009-14*, p. 23.

not permit the customers to be re-assigned to a time of use tariff as there has been no change to their load or connection characteristics.[19]

Dispute resolution arising from a re-assignment of customers

Integral Energy submitted that it is concerned about the AER becoming the dispute resolution body for any dispute arising from the reassignment of customers. Integral Energy noted that as the majority of customers are 'small' customers they would be covered by the Energy & Water Ombudsman NSW. Integral Energy noted that the Ombudsman would be the more appropriate body for the referral of such disputes.[20]

Integral Energy submitted that if the AER decided it will be the dispute resolution body for matters relating to reassignments, then the AER should revisit section 12 of appendix A of the draft decision. This section should be revised to state that if the AER does not make a decision within 30 business days of receiving a relevant request, then the reassignment should proceed to ensure that there are no unintended barriers to the introduction of innovative tariff and metering options.[21]

2.4.2 City of Sydney

The City of Sydney submitted that the AER should remove barriers for reassigning customers to tariff classes, particularly in relation to time of use tariffs.[22]

The City of Sydney submitted that the draft decision on reassignment of customers to tariff classes is restrictive and obstructs the movement of customers from fixed rate tariffs to time of use tariffs, particularly when customers volunteer to switch over.[23]

2.4.3 Origin Energy

Origin Energy submitted that meter services should be unbundled from standard network use of system (NUOS) charges. Origin Energy stated that this would bring NSW in line with current practice in Victoria and the approach set out in the AER's framework and approach paper for ETSA utilities.[24]

Origin Energy submitted that whilst metering charges remain bundled with NUOS charges, metering costs will be smeared within NUOS charges. Origin Energy stated that this creates a significant barrier to the alternative provision of metering services. Origin Energy submitted that metering service charges need to be explicitly separated from NUOS to promote contestability of small customer metering services.[25]

Origin Energy submitted that if the NSW DNSPs were to unbundle these charges, small customers would be more likely to voluntarily install a smart meter to better manage individual electricity consumption without the risk of incurring duplicate metering and data service provision charges. Origin Energy noted that in the Adelaide Solar Cities project, it was required to pay its vendors for meter provision and meter data services but

[19] Integral Energy, *Submission to the AER*, p. 23.
[20] Integral Energy, *Submission to the AER*, p. 24.
[21] Integral Energy, *Submission to the AER*, p. 24.
[22] City of Sydney, *Submission to the Australian Energy Regulator on the NSW Draft distribution network pricing determination 2009-2014*, Explanatory paper, pp. 13–14.
[23] City of Sydney, *Submission to the AER*, p. 13.
[24] Origin Energy, *NSW draft distribution determination 2009–10 to 2013–14*, 24 February 2009, p. 2.
[25] Origin Energy, p. 2.

was also liable for the smeared cost of basic meter provision and meter data services within the bundled NUOS charges. This occurred even though the DNSP owned meter and data services were replaced. Origin Energy submitted that effectively each customer had to pay metering provision and data service charges twice.[26]

2.4.4 EnergyAustralia

EnergyAustralia submitted that it supports the intent of Integral Energy's suggestion that installation of a time of use meter is a change in connection characteristics. EnergyAustralia stated that if a broader view is taken of connection characteristics then Integral Energy's suggested approach would work.[27]

EnergyAustralia accepted Integral Energy's comment that, to the extent customers have redress through an industry ombudsman, that is the procedure through which disputes regarding tariff assignment should be managed. EnergyAustralia also supported Integral Energy's suggestion that section 12 of appendix A of the draft decision should be revised so that if the AER does not make a decision within 30 business days of receiving the relevant request then the re–assignment should proceed. EnergyAustralia restated that it supports a presumption that the DNSP is entitled to change customers' tariffs if it can demonstrate it complied with approved procedures.[28]

2.5 Issues and AER considerations

2.5.1 Classification of services

In its revised regulatory proposal EnergyAustralia stated that it has not revised its original proposal in which it sought to vary the classification of certain services.[29]

Insufficient information to vary classifications

EnergyAustralia submitted that it had provided a very detailed assessment of the reasons it believed it was appropriate for the classification of the services to be varied or for certain services not to be treated as distribution services.[30]

In assessing EnergyAustralia's proposal to vary the classification of some services the AER would consider the market for those services, the potential for competition to develop in the provision of those services, the form of regulation previously applicable to the services and the desirability of consistency in the form of regulation for similar services.[31] The AER notes that EnergyAustralia's analysis in its regulatory proposal of the market for metering services and customer funded connections is brief and no significant new information is provided in its revised regulatory proposal.[32] For example, EnergyAustralia has not provided the AER with detailed analysis of the markets for these services. EnergyAustralia has only provided the AER with a summary of its conclusions.

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26 Origin Energy, p. 2.
27 EnergyAustralia, *Response to stakeholder submissions on AER's draft determination*, 6 March 2009, attachment, p. 33.
28 EnergyAustralia, *Response to stakeholder submissions*, attachment, p. 33.
29 EnergyAustralia, *Revised regulatory proposal*, p. 147.
30 EnergyAustralia, *Revised regulatory proposal*, p. 148.
31 This is discussed further in the 'IPART's current regulatory approach' section below.
32 EnergyAustralia, *Regulatory proposal*, June 2008, p. 173; and EnergyAustralia, *Revised regulatory proposal,* p. 148.

Therefore, in order for the AER to properly assess the matter, it would have to undertake a detailed market analysis which, amongst other things, would require making inquiries of the participants in these markets regarding the level of competition and EnergyAustralia's proposal. As the AER indicated in the draft decision, these are matters which the AER would be able to fully investigate and consider as part of the normal framework and approach paper process.[33] The AER notes, however, that it was not required to undertake the framework and approach paper process under the transitional chapter 6 rules due to the truncated timelines which apply to the NSW distribution determinations for the next regulatory control period.

In relation to customer specific services and emergency recoverable works, EnergyAustralia has restated in its submission that these services are not distribution services.[34] However, EnergyAustralia has not provided the AER with any additional information in relation to the services. The AER does not agree with EnergyAustralia's submission that the issue is essentially a matter of legal analysis which can be considered by the AER as part of its consideration of EnergyAustralia's proposal.[35] The AER requires greater understanding of the nature of these services before it could consider the matter from a legal perspective. As noted in the draft decision, this is something the AER can undertake as part of the framework and approach paper process for the 2014–2019 regulatory control period.[36] The AER notes that it is implicit in the transitional chapter 6 rules[37] and expressly stated in IPART's final determination for the current regulatory control period[38] that customer specific services and emergency recoverable works are distribution services. The AER would need to thoroughly consider the matter before making a decision. The truncated timelines which apply to the NSW distribution determinations for the next regulatory control period have resulted in insufficient time on this occasion to review whether these services are distribution services. The AER would need to make inquiries of interested parties before it could consider the matter from a legal perspective. The AER is not prepared to undertake the legal analysis without such information.

Under the regulatory framework established by the transitional chapter 6 rules, each DNSP must submit a complete regulatory proposal for consideration by the AER. The AER is only obliged to respond to the information provided by a DNSP. EnergyAustralia has not provided the AER with sufficient information to enable it to form a view on the matters raised. The AER notes that EnergyAustralia elected not to provide any new information of substance in its revised regulatory proposal.

AER's reasons for its draft decision on the classification of services

The AER confirms it considered the substance of EnergyAustralia's proposal regarding the services and took the proposal into account in making its draft decision on the matter.

Clause 6.10.2(a)(3) of the transitional chapter 6 rules provides that the AER must publish its reasons for suggesting the distribution determination should be made as proposed

33 AER, *Draft decision*, p. 18.
34 EnergyAustralia, *Revised regulatory proposal*, p. 148.
35 EnergyAustralia, *Revised regulatory proposal*, p. 148.
36 AER, *Draft decision*, p. 18.
37 NER, transitional chapter 6 rules, clauses 6.2.3B(a) and (b).
38 IPART, *NSW Electricity distribution pricing 2004/05 to 2008/09*, *Final determination*, Determination no 2, 2004, June 2004, clause 2.

including the draft constituent decisions. One of the constituent decisions is a decision on the classification of the services provided by the DNSP.[39] In the draft decision, the AER decided that the service classifications deemed by clause 6.2.3B of the transitional chapter 6 rules will apply to all NSW DNSPs.[40] The AER is of the view that it has provided adequate reasons for that decision.[41]

IPART's current regulatory approach

EnergyAustralia submitted that it was irrelevant for the AER to consider IPART's current approach to the classification of services.[42] The AER does not agree with this submission.

The AER notes that the transitional chapter 6 rules do not provide any guidance on the factors the AER should have regard to when considering a request to reclassify distribution services for the next regulatory control period. However, under the general chapter 6 rules of the NER, when classifying a distribution service under clause 6.2.1(c), the AER must have regard to:

(1) the form of regulation factors; and

(2) the form of regulation (if any) previously applicable to the relevant service or services and, in particular, any previous classification under the present system of classification or under the previous regulatory system (as the case requires); and

(3) the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction); and

(4) any other relevant factor.

The form of regulation factors are set out in section 2F of the NEL and are:

(a) the presence and extent of any barriers to entry in a market for electricity network services;

(b) the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other electricity network service provided by the network service provider;

(c) the presence and extent of any network externalities (that is, interdependencies) between an electricity network service provided by a network service provider and any other service provided by the network service provider in any other market;

(d) the extent to which any market power possessed by a network service provider is, or is likely to be, mitigated by any countervailing market power possessed by a network service user or prospective network service user;

(e) the presence and extent of any substitute, and the elasticity of demand, in a market for an electricity network service in which a network service provider provides that service;

[39] NER, transitional chapter 6 rules, clause 6.12.1(1).
[40] AER, *Draft decision*, pp. 22–24.
[41] AER, *Draft decision*, pp. 17–18.
[42] EnergyAustralia, *Revised regulatory proposal*, p. 150.

(f) the presence and extent of any substitute for, and the elasticity of demand in a market for, electricity or gas (as the case may be);

(g) the extent to which there is information available to a prospective network service user or network service user, and whether that information is adequate, to enable the prospective network service user or network service user to negotiate on an informed basis with a network service provider for the provision of an electricity network service to them by the network service provider.

In addition, clause 6.2.1(d) of the general chapter 6 rules provides that:

> In classifying distribution services that have previously been subject to regulation under the present or earlier legislation, the AER must act on the basis that, unless a different classification is clearly more appropriate:
>
> (1) there should be no departure from a previous classification (if the services have been previously classified); and
>
> (2) if there has been no previous classification – the classification should be consistent with the previously applicable regulatory approach.

The general chapter 6 rules will not apply to the NSW DNSPs' distribution determinations until the 2014–2019 regulatory control period. However, the AER is of the view that should it need to consider the classification of services under the transitional rules, it should have regard to these principles if it were to reclassify distribution services for the next regulatory control period. If the AER was considering reclassifying the services, it would seek submissions from interested parties on the proposal, including these principles. The AER notes, however, that the policy makers have considered how distribution services should be classified and they decided not to include in the transitional chapter 6 rules a provision which provides guidance on how services should be classified (such as clause 6.2.1 of the general chapter 6 rules). Instead, they introduced the deeming provisions in clause 6.2.3B of the transitional chapter 6 rules.

In the draft decision, the AER noted that EnergyAustralia had not applied to IPART for a determination that any of the excluded distribution services for which it sought reclassification as unclassified services, satisfied IPART's competition test.[43] In the AER's view, the matters which need to be considered under IPART's competition test[44] and in clause 6.2.1 of the general chapter 6 rules are, in effect, substantially similar. Therefore, it is relevant for the AER to have regard to whether EnergyAustralia applied to IPART for a determination that the competition test has been satisfied for any of EnergyAustralia's excluded distribution services.

In any event, EnergyAustralia stated that it did consider applying to IPART to reclassify metering services (types 1–4). After discussing the matter with IPART, EnergyAustralia decided that 'because of the complexity of the proposed test, the resources which would have been required to mount a case for reclassification were not warranted' and that such resources were 'significant'.[45] The AER is also of the view that consideration of any reclassification of a service will necessarily be complex and will involve considerable

43 AER, *Draft decision*, p. 17.
44 IPART, *NSW Electricity distribution pricing 2004/05 to 2008/09*, *Final determination, Regulation of excluded distribution services rule 2004*, June 2004, Appendix 2: Competition test.
45 EnergyAustralia, *Revised regulatory proposal*, p. 150.

resources and time. This is one of the reasons why, in the context of the truncated timelines which apply to the distribution determinations for the next regulatory control period, the AER decided it would be more appropriate to consider these matters during the framework and approach paper process in anticipation of the distribution determination for the 2014–2019 regulatory control period.[46]

EnergyAustralia also submitted that the AER has not considered the level of regulation that IPART actually applied to excluded distribution services during the current regulatory control period.[47] EnergyAustralia noted that excluded distribution services were regulated by IPART under the regulation of excluded distribution services rule as follows:

- pricing of services was subject to pricing principles
- information disclosure requirements were to apply
- price monitoring arrangements were to be established.[48]

EnergyAustralia noted that IPART did not appear to implement price monitoring during the course of the current regulatory control period resulting in regulation which was 'so light handed as to be virtually non-existent'. EnergyAustralia submitted that, in this circumstance, it did not warrant committing significant resources to satisfy IPART's competition test.[49]

The AER has reviewed IPART's regulation of excluded distribution services rule[50] and that part of IPART's final report which deals with excluded distribution services.[51] The AER notes that IPART indicated in its final report that it would monitor prices of excluded distribution services on a market surveillance basis. If it received a complaint, it would investigate whether the price satisfied the pricing principles and whether the information disclosure requirements had been met.[52] This was reflected in the excluded services rule as a requirement for each DNSP to provide IPART with such information required by IPART to investigate any complaint concerning non-compliance.[53] EnergyAustralia has not submitted that any complaints were made. This indicates to the AER that the price monitoring regime has worked irrespective of whether IPART monitored prices on a proactive or reactive basis.

The AER notes that according to clause 6.2.3B(c) of the transitional chapter 6 rules, in relation to its customer funded connections, customer specific services and metering services (types 1–4), a DNSP is required to comply substantially with the requirements of IPART's excluded distribution services rule for the next regulatory control period. This means that these services will continue to be subject to the same form of regulation for the next regulatory control period which they are subject to in the current regulatory control period. Since EnergyAustralia has described that regulation as 'so light handed as

46 AER, *Draft decision*, p. 18.
47 EnergyAustralia, *Revised regulatory proposal*, p. 150.
48 EnergyAustralia, *Revised regulatory proposal*, p. 150.
49 EnergyAustralia, *Revised regulatory proposal*, p. 150.
50 IPART, *Regulation of excluded distribution services rule 2004*.
51 IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Report*, *Other paper No 23*, June 2004, pp. 171–172.
52 IPART, *NSW Electricity Distribution Pricing Final Report*, p. 172.
53 IPART, *Regulation of excluded distribution services rule 2004*, clause 2.2(b).

to be virtually non-existent',[54] the AER is not aware of any compelling reason for the services to be reviewed as part of the distribution determination for the next regulatory control period. EnergyAustralia has not demonstrated that there is any urgency for conducting the review as part of the current process in circumstances where the AER has not been given the opportunity under the transitional chapter 6 rules to undertake the normal framework and approach process. The AER notes that the transitional chapter 6 rules do not provide sufficient time for a thorough review to be undertaken and explicitly deem the service classifications for the next regulatory control period.

The AER confirms its decision that the proposed reclassification of the services should be considered as part of the framework and approach process in anticipation of the distribution determination for the 2014–2019 regulatory control period. This will give the AER sufficient time to undertake a thorough review of the matter and consult with parties other than EnergyAustralia.

Presumption in favour of not reclassifying services

EnergyAustralia submitted that the AER is obliged to be satisfied that services classified by IPART as distribution services are in fact distribution services particularly if a detailed analysis was submitted casting doubt on the classification.[55] The AER does not accept that it is under any such obligation. The AER is not aware of any provision in the transitional chapter 6 rules which obliges the AER to satisfy itself that services classified by IPART as distribution services are in fact distribution services—even if it is submitted that services have been incorrectly classified. If such an obligation existed then it is not clear to the AER why it would be necessary for the Ministerial Council on Energy (MCE) to include the deeming provisions of clause 6.2.3B in the transitional chapter 6 rules and why they did not include a framework and approach paper process or some variant of it. As discussed in the draft decision, the AER has formed the view that the information provided to the AER is not sufficient for it to be able to satisfy itself that:

- customer specific services and emergency recoverable works are not distribution services
- a different classification for metering services (types 1–4), customer funded connection, customer specific services and emergency recoverable works is clearly more appropriate for the next regulatory control period.[56]

EnergyAustralia asserted that it has provided the AER with a 'detailed analysis' and has 'advanced cogent arguments' which are sufficient for the AER to make a decision regarding the classification of services.[57] The AER confirms that it has reviewed and considered this material and does not agree that the information provided is sufficient for that purpose.

EnergyAustralia submitted that it does not agree with the AER's view that there is a strong presumption in the transitional chapter 6 rules that the deemed classifications should be followed unless a DNSP can satisfy the AER that a different classification is clearly more appropriate.[58] The AER notes that when it classifies services under the

[54] EnergyAustralia, *Revised regulatory proposal*, p. 150.
[55] EnergyAustralia, *Revised regulatory proposal*, p. 151.
[56] AER, *Draft decision*, p. 18.
[57] EnergyAustralia, *Revised regulatory proposal*, p. 151.
[58] EnergyAustralia, *Revised regulatory proposal*, p. 151.

general chapter 6 rules and those services have been previously subject to regulation under present or earlier legislation, the AER must act on the basis that unless a different classification is clearly more appropriate there should be no departure from a previous classification if those services have been previously classified.[59] Since this presumption exists under the general chapter 6 rules, the AER considers that it is prudent and appropriate to apply the presumption when considering requests for service reclassifications under the transitional chapter 6 rules. This is particularly the case because the transitional chapter 6 rules explicitly deem the service classifications for the next regulatory control period and do not provide for the AER to undertake the normal framework and approach paper process. The AER notes that there is no service classification deeming provision in the general chapter 6 and the services in question have been previously classified by IPART.

EnergyAustralia submitted that even if the presumption exists, the AER must properly consider and engage with the substance of EnergyAustralia's arguments in order to decide whether the presumption is outweighed.[60] The AER notes that in order for it to properly consider and engage with the substance of EnergyAustralia's arguments, EnergyAustralia should have provided the AER with a fully developed and detailed analysis of the matter as part of its regulatory proposal.

The AER's decision to delay consideration of the issue

EnergyAustralia submitted that the AER is obliged to consider and make a decision on the material that has been put before the AER and has acted unreasonably by delaying proper consideration of the issues for five years.[61]

The AER has properly considered the matters raised in EnergyAustralia's proposal in support of the reclassification of services. However, the information provided by EnergyAustralia was not sufficient for the AER to undertake a full consideration of the matter so the AER decided not to reclassify the services.[62] Since it is for EnergyAustralia to provide the AER with sufficient information to satisfy the AER (and it has not done so), the AER has no choice but to consider the matter as part of the framework and approach paper process in anticipation of the distribution determination for the 2014–2019 regulatory control period—should EnergyAustralia seek the reclassifications at that time.

The AER notes EnergyAustralia's submission that the level of competition in the provision of connection services and metering services (types 1–4) differs markedly with each DNSP's territory and the applicable jurisdictional arrangements.[63] The AER considers this further supports its view that a detailed analysis of the markets for these services needs to be undertaken. However, that analysis cannot be properly undertaken and completed within truncated timelines which apply to the NSW distribution determinations for the next regulatory control period. As noted in the draft decision, the AER is prepared to consider a fully developed and detailed analysis prepared by

59 NER, general chapter 6 rules, clause 6.2.1(d).
60 EnergyAustralia, *Revised regulatory proposal*, p. 151.
61 EnergyAustralia, *Revised regulatory proposal*, p. 152.
62 AER, *Draft decision*, p. 18.
63 EnergyAustralia, *Revised regulatory proposal*, p. 152.

EnergyAustralia as part of the framework and approach paper process for the 2014–2019 regulatory control period.[64]

Unbundling of metering services from NUOS charges

Origin Energy submitted that meter services should be unbundled from standard NUOS charges to promote contestability of small customer metering services and remove a significant barrier to the alternative provision of metering services.[65]

The AER supports the prospect of greater competition in the provision of metering services. However, in assessing Origin Energy's proposal, the AER would need to consider the market for the services, the potential for competition to develop in the provision of the services, the form of regulation previously applicable to the services and the desirability of consistency in the form of regulation for similar services.[66] In order for the AER to properly assess the matter it would need to undertake a thorough and detailed market analysis which, amongst other things, would require making inquiries of the participants in these markets regarding the level of competition and Origin Energy's proposal. These are matters which the AER would be able to fully investigate and consider as part of the normal framework and approach paper process. The AER notes, however, that it was not required to undertake the framework and approach paper process under the transitional chapter 6 rules due to the truncated timelines which apply to the NSW distribution determinations for the next regulatory control period. The AER is prepared to consider the matter as part of the framework and approach paper process for the 2014–2019 regulatory control period should Origin Energy decide to make a submission at that time.

The AER understands that the MCE has issued a policy direction to the effect that the DNSPs will be legislatively obliged to roll-out smart meters to residential and other small customers in those jurisdictions where a mandated roll-out will take place.[67] The MCE has stated that a DNSP who is obliged to roll-out smart meters should have exclusivity over meter provision and responsibility for related metering data provision in respect of the customers covered by the mandate during the period in which the DNSP must complete the mandate.[68] The AER also understands that it is proposed to change the NER so a minister of a participating jurisdiction can make a determination that a DNSP must ensure that specified customers are provided with smart metering services.[69]

The AER also notes that if the NSW Government grants the NSW DNSPs a monopoly for the purposes of a mandated advance meter roll-out, the DNSPs should be transparent about how their costs will be recovered so third parties are better able to compete with the DNSPs in the provision of alternative metering services.

64 AER, *Draft decision*, p. 18.
65 Origin Energy, p. 2.
66 This is discussed further in the 'IPART's current regulatory approach' section.
67 MCE, *Statement of Policy Principles*, June 2008, clause 2.
68 MCE, *Statement of Policy Principles*, June 2008, clause 3.
69 MCE, *National Electricity Law Changes for Smart Meter Roll-Outs and Trials - Explanatory Note*, p. 3.

2.5.2 Assigning customers to tariff classes

Consideration of EnergyAustralia's proposal

EnergyAustralia submitted there was no indication that the AER gave any consideration to EnergyAustralia's proposal in relation to assigning customers to tariff classes.[70] EnergyAustralia's proposal is set out in chapter 1 of part III of its regulatory proposal.[71]

The AER acknowledges that EnergyAustralia's proposal in relation to assigning customers to tariff classes was not expressly mentioned in the draft decision. The AER considers that the procedures for assigning and reassigning customers to tariff classes set out in EnergyAustralia's regulatory proposal are not inconsistent with the AER's revised procedures set out in this decision. The AER considers that the procedures it has developed are appropriate generic procedures that the NSW DNSPs can use to guide the development of detailed internal procedures, such as those provided by EnergyAustralia.

Tariff reform and initiatives

EnergyAustralia submitted that section 5 of the AER's proposed procedures set out in appendix A of the draft decision appears to limit reassignment to instances where:

- an existing customer's load or connection characteristics have changed so that the customer's existing tariff is no longer appropriate; or
- a customer no longer has the same or materially similar load or connection characteristics as the other customers on the customer's existing tariff.[72]

Integral Energy submitted that the wording of section 5 of appendix A of the draft decision should be modified so a change in connection characteristics specifically includes the installation of a meter with time of use capabilities in order to enable the reassignment of the customer to a time of use tariff.[73] Integral Energy also submitted that the process in the proposed procedures would not permit customers to be reassigned to a time of use tariff as there has been no change to their load or connection characteristics.[74] The City of Sydney submitted that the AER should remove barriers for reassigning customers to tariff classes particularly in relation to time of use tariffs.[75]

Section 5 of the AER's proposed procedures set out in appendix A of the draft decision was not intended to apply a restriction on the circumstances in which a reassignment can take place. The AER considers that it is not necessary to make any changes to the section because the language of the section does not impose any limits, or state that it sets out the only circumstances, in which a reassignment can occur. However, the AER has inserted a footnote to section 3(b) of the proposed procedures to make it clear that 'connection' can include the installation of smart meters.

70 EnergyAustralia, *Revised regulatory proposal*, p. 183.
71 EnergyAustralia, *Regulatory proposal,* pp. 204–207.
72 EnergyAustralia, *Revised regulatory proposal*, p. 184.
73 Integral Energy, *Submission to the AER*, p. 23.
74 Integral Energy, *Submission to the AER*, p. 23.
75 City of Sydney, *Submission to the AER*, pp. 13–14.

System for assessment and review

EnergyAustralia submitted that clause 6.18.4(a)(4) of the transitional chapter 6 rules does not contemplate or require development of a procedure that effectively introduces external review by the AER and that the AER is not empowered to create or impose the proposed dispute resolution procedure.[76]

The AER does not agree with EnergyAustralia's interpretation of clause 6.18.4(a)(4). The AER considers that it, or another independent party, is able to conduct the assessment and review contemplated by the clause. If it was only intended that an internal assessment and review was to be undertaken it would not have been necessary to include the provision in the transitional chapter 6 rules. Each DNSP should have adequate and documented internal procedures which set out the process the DNSP will follow, and the criteria it will apply, in assessing and determining tariff assignments and reassignments. The AER expects that it would be standard commercial practice for an organisation to conduct a review whenever a customer objects to an unrequested tariff reassignment. If a customer decides to object to a tariff assignment or reassignment, the DNSP should be able to demonstrate to the customer that the DNSP has complied with its own internal procedures. If it is established that the DNSP has correctly followed its internal procedures, and applied the criteria correctly, then the DNSP's decision should be upheld.

In any event, the AER notes that under the *Electricity Supply Act 1995* (NSW), a small retail customer may apply to a DNSP for a review of a decision of the DNSP regarding any matter under the customer connection contract.[77] The *Electricity Supply (General) Regulation 2001* (NSW) sets out the procedure to be followed for the internal review of the decision.[78] In addition, it is a condition of a DNSP's licence that it is a member of an approved electricity industry ombudsman scheme. The DNSP is also bound by any decision of the ombudsman relating to a dispute with a small retail customer.[79] The AER understands that the approved electricity industry ombudsman scheme in NSW is administered by the Energy & Water Ombudsman NSW.[80] The AER notes Integral Energy's submission that the ombudsman would be more appropriate than the AER for referral of any disputes.[81]

The AER notes that under the *Electricity Supply Act 1995* (NSW), a standard form customer connection contract must make provision for the procedures for handling complaints made by customers and resolving disputes with customers.[82] The AER understands that the DNSPs have included dispute resolution provisions in their customer connection contracts under which disputes (including disputes regarding tariff assignments and reassignments) are managed as follows:[83]

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76 EnergyAustralia, *Revised regulatory proposal*, p. 187.

77 *Electricity Supply Act 1995 (NSW)*, section 96(2). Under section 92 of the Act and clause 7 of the *Electricity Supply (General) Regulation 2001 (NSW)*, a 'small retail customer' includes a person who consumes electricity at less than 160 MWh per year.

78 *Electricity Supply (General) Regulation 2001 (NSW),* clauses 47, 48 and 49.

79 *Electricity Supply Act 1995 (NSW)*, section 96C.

80 The Energy & Water Ombudsman NSW website can be found at www.ewon.com.au.

81 Integral Energy, *Submission to the AER*, p. 24.

82 *Electricity Supply Act 1995 (NSW)*, section 20(1)(f). See also clause 40(2)(a) and schedule 1 (clause 1(3)(j)) of the *Electricity Supply (General) Regulation 2001 (NSW).*

83 See, for example, Country Energy, *Standard Form Customer Connection Contract* (clause 11 and schedule 4); EnergyAustralia, *Standard Form Customer Connection Contract* (clause 15 and

- if the customer is not satisfied with the DNSP's determination following the DNSP's internal review, the dispute can be referred to the Energy & Water Ombudsman NSW if it is a dispute within the ombudsman's jurisdiction
- if the dispute is not within in the ombudsman's jurisdiction, the dispute can be referred to some other form of alternative dispute resolution (e.g. independent arbitration).

Clause 6.18.4(a) of the transitional chapter 6 rules provides that the AER must have regard to the principles set out in that clause when formulating provisions of a distribution determination governing the assignment or reassignment of customers to tariff classes. One of those principles is that a DNSP's decision to assign or reassign a customer to a tariff class should be subject to an effective system of assessment and review.[84] The AER considers that this principle contemplates that the AER has a role in the assessment and review process in order that the process can be effective. Such a role is also necessary if there is no limitation on the circumstances in which a DNSP can assign or reassign tariffs. In order that the system of assessment and review can be effective, there must be some form of oversight by an independent third party. The AER considers, however, that in light of the alternative dispute resolution procedures which are currently available to customers, it does not need to implement a further layer of review. The AER considers that the current dispute resolution procedures strike the appropriate balance between customers having a fair hearing of their objections and DNSPs ability to move customers onto tariffs which better reflect customers usage and connection to the network. This provides an effective system of assessment and review through third party oversight. As a consequence, the AER has revised the procedures for assigning and re-assigning customers to tariff classes to remove the AER's proposed layer of review. In addition, the procedures have been updated to make it explicit that any customer can seek independent review of a DNSP's tariff assignment or reassignment decision.

Notifying customers of proposed reassignment

EnergyAustralia submitted that its network business is not privy to the tariff assignment applied by retailers to their customers and that, in practice, its network business has notified retailers in advance of tariff reassignments for bulk transfers. The retailer may or may not notify the customer depending on whether they pass through the tariff.[85] Section 6 of the AER's proposed procedures required the DNSP to give prior notice to customers of reassignments.

The AER acknowledges that, in practice, DNSPs may not be able to notify customers of proposed tariff assignments or reassignments. If this is the case, the DNSP can notify the retailer instead of the customer. The AER has amended section 6 of the proposed procedures to reflect this change.

Reasons for decision

EnergyAustralia noted that the AER is not required to give reasons in writing for decisions made under section 11 of the proposed procedures. EnergyAustralia also noted that it is required to provide reasons in writing for its decisions under section 8 of the

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attachment 3); and Integral Energy, *Standard Form Customer Connection Contract* (clause 13) and Procedures for customer complaints, appeals and dispute resolution.

84 NER, transitional chapter 6 rules, clause 6.18.4(a)(4).

85 EnergyAustralia, *Revised regulatory proposal*, p. 187.

proposed procedures. EnergyAustralia submits that this requirement is onerous and unfair and the AER should not exempt itself from the requirement to give reasons.[86]

In accordance with good regulatory practice, the AER would have provided written reasons for any decisions it made under section 11 of the proposed procedures. However, since the AER is no longer proposing to review objections to tariff reassignments, the provision will not appear in the revised procedures. The AER notes that it does not propose to review objections from customers regarding tariff assignments. EnergyAustralia has submitted that it is onerous for it to provide written reasons for its decisions under section 8 of the proposed procedures.[87] The AER notes that EnergyAustralia is required under clause 48(3)(a) of the *Electricity Supply (General) Regulation 2001* (NSW) to provide written reasons of its internal review of complaints made by small retail customers. Relevantly, clause 1.3(c)(i) of attachment 3 of EnergyAustralia's standard form customer connection contract[88] states that it will provide a customer with written notice of its determination following the internal review of its decisions under the contract together with the reasons for the determination. Since these reasons would be the same as the reasons for the decision under section 8 of the proposed procedures, the AER does not accept that it would be onerous for EnergyAustralia to provide the reasons in writing under the proposed procedures.

Deemed decision making

Section 12 of the proposed procedures deem the AER to have decided against the reassignment if the AER does not notify the customer and relevant DNSP of its decision within 30 business days of the customer requesting the AER to decide on the matter. EnergyAustralia submitted that this disadvantages the DNSP and provides no incentive for the AER to resolve disputes in an efficient manner.[89] Integral Energy submitted that there is no appropriate incentive for the AER to resolve the matter in a timely manner, particularly if a large number of customers are proposed to be reassigned.[90]

The AER notes that since the AER is no longer proposing to review objections to tariff reassignments, the deemed decision making provision will not be used in the revised procedures. In addition, the AER notes that it does not propose to review objections from customers regarding tariff assignments.

WAPC reasonable estimates

Integral Energy submitted it is concerned there might be an inconsistency between the arrangements for assignment of customers to tariffs under the AER's proposed procedures and the methodology for calculating reasonable estimates for the WAPC under appendix J of the draft decision.[91] Integral Energy submitted that if the assignment of customers is deemed reasonable at the time the WAPC is approved then the assignment should be allowed to proceed. It stated to do otherwise results in a flawed process for the WAPC reasonable estimates.[92] Integral Energy notes that under the AER's proposed

86 EnergyAustralia, *Revised regulatory proposal*, p. 188.
87 EnergyAustralia, *Revised regulatory proposal*, p. 187.
88 EnergyAustralia, *Standard Form Customer Connection Contract*, October 2001 [Amendment No 1 – April 2002] [Amendment No 2 – February 2005] [Amendment No 3 – November 2006].
89 EnergyAustralia, *Revised regulatory proposal*, p. 188.
90 Integral Energy, *Submission to the AER*, p. 24.
91 Integral Energy, *Revised regulatory proposal*, p.88.
92 Integral Energy, *Revised regulatory proposal*, p.88.

procedures, a customer's objection to assignment to a new tariff may be upheld by the AER resulting in the customer remaining on their original tariff even though it was assumed the customer would be assigned to the new tariff when prices were calculated for the year.[93]

The AER notes that it is no longer proposing to review objections to tariff reassignments. However, in light of Integral Energy's concerns, the AER has inserted a new provision in the proposed procedures under which a DNSP can adjust prices if a customer's objection to a tariff assignment or reassignment is upheld in order to correct any imbalance which may have occurred. The adjustment would be made as part of the next annual review of prices and is necessary because the tariffs for other customers will be affected if a customer's objection to a tariff assignment or reassignment is upheld.

Selection of tariffs by customers and retailers

As noted in chapter 2 of ActewAGL's final decision, the AER confirms that the procedures for assigning customers to tariffs set out in the draft decision do not prevent consumers and retailers from selecting the most appropriate network charge.

Revised procedures for assigning and reassigning customers to tariff classes

The AER has prepared a revised set of procedures in relation to assigning and reassigning customers to tariff classes. The revised procedures are set out in appendix A of this final decision. The NSW DNSPs can continue to use their own procedures in conjunction with the AER's revised procedures provided the AER's revised procedures prevail to the extent of any inconsistency.

2.6 AER conclusion

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

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

93 Integral Energy, *Revised regulatory proposal*, p. 88.

2.7 AER decision

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

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

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

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

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

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

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

3 Arrangements for negotiation

3.1 Introduction

A negotiated distribution service for the purposes of the NER is defined as a distribution service that is a negotiated network service under section 2C of the NEL. Section 2C of the NEL provides that a negotiated network service is a service:

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

Country Energy and Integral Energy do not have any services classified as negotiated distribution services in the next regulatory control period. Clause 6.1.6(d) of the transitional chapter 6 rules deems EnergyAustralia's negotiated transmission services to be classified as negotiated distribution services. Part D of the transitional chapter 6 rules applies to EnergyAustralia's negotiated distribution services.

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

This chapter sets out the AER's consideration of issues raised in response to the draft decision. It sets out the AER's decisions regarding the arrangements facilitating negotiation for certain distribution services for the next regulatory control period, specifically:

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

3.2 AER draft decision

The draft decision defined a negotiable component of a direct control service as any component of a direct control service (or the terms and conditions on which that direct control service or component are provided) where:[94]

[94] AER, *Draft decision*, p. 29.

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

The NCC for the NSW DNSPs was set out in appendix B of the draft decision.

The NDSC for EnergyAustralia was set out in appendix C of the draft decision.

The AER approved the NSW DNSPs' negotiating frameworks to apply for the next regulatory control period. Country Energy's, EnergyAustralia's and Integral Energy's negotiating frameworks were in appendices D, E and F of the draft decision, respectively. The AER considered that the negotiating frameworks comply with part DA of the transitional chapter 6 rules and, in the case of EnergyAustralia's negotiating framework, part D of the transitional chapter 6 rules.[95]

3.3 Revised regulatory proposals

Country Energy

Country Energy accepted the draft decision.[96]

EnergyAustralia

Negotiable components

EnergyAustralia did not accept the AER's definition of a negotiable component of a direct control service.[97] EnergyAustralia resubmitted its definition of a negotiable component as part of its revised regulatory proposal, with the following comments in response to the draft decision:[98]

- the definition proposed in the draft decision is inconsistent with EnergyAustralia's proposal and appeared to be inconsistent with the AER's own reasoning and analysis
- there are inconsistencies between the AER's definition and the Ministerial Council on Energy's (MCE) policy intent
- the AER's definition is inconsistent with other aspects of the regulatory framework.

95 AER, *Draft decision*, p. 38.
96 Country Energy, *Revised regulatory proposal*, p. 9.
97 EnergyAustralia, *Revised regulatory proposal*, p. 153.
98 EnergyAustralia, *Revised regulatory proposal*, pp. 153–154.

EnergyAustralia submitted that the AER should revisit its considerations and revise its definition of a negotiable component, preferably in line with what EnergyAustralia proposed in its regulatory proposal. EnergyAustralia stated that:[99]

- the AER's definition leads to a much broader outcome than that envisaged by EnergyAustralia's proposal and the AER's analysis
- the AER's definition is not wide enough to cover all the examples proposed by EnergyAustralia.

The AER understands that EnergyAustralia submitted that as a minimum, if the AER continues with the use of its proposed definition, it should clarify that the following are excluded from 'connection services' referred to in the third limb of the AER's proposed definition:[100]

- amounts in relation to the design and construction of new capital works funded by the user (i.e. customer funded connections)—they are not direct control services
- prices for monopoly services—they are covered by separately regulated prices
- amounts in relation to new capital works to be constructed to accommodate new connections which are funded by the user—they are covered by IPART's capital contributions determination—provided an equivalent set of regulatory principles is developed to cover generator connections.

EnergyAustralia noted that negotiated services arrangements would apply to public lighting services. EnergyAustralia stated that it is not clear how public lighting is to be treated under the AER's proposed definition.[101]

EnergyAustralia noted that it and other DNSPs made strong submissions to establish that the transmission negotiated service definition should not apply to distribution—this argument was accepted by the MCE when developing the transitional chapter 6 rules. EnergyAustralia submitted that, in effect, the AER has reversed the MCE's decision by applying the transmission negotiated service definition to the definition of negotiable components of direct control services.[102]

EnergyAustralia submitted that the intent of part DA of the transitional chapter 6 rules is for particular components—rather than whole services—to be classified as negotiable. EnergyAustralia stated that the AER's definition is in broad terms—particularly the third limb—which is capable of capturing or impacting upon just about every aspect of a 'connection service'. EnergyAustralia noted that the NER definition of 'connection service' is not a 'component' but an entire multi–layered service.[103]

NDSC and NCC

EnergyAustralia did not accept the draft decision to reject most of the issues raised by EnergyAustralia in its submission on the proposed NDSC and NCC.[104] EnergyAustralia reiterated its submission subject to a revision to the NCC. EnergyAustralia sought a

[99] EnergyAustralia, *Revised regulatory proposal*, p. 154.
[100] EnergyAustralia, *Revised regulatory proposal*, pp. 156 and 159–160.
[101] EnergyAustralia, *Revised regulatory proposal*, p. 158.
[102] EnergyAustralia, *Revised regulatory proposal*, p. 158.
[103] EnergyAustralia, *Revised regulatory proposal*, pp. 158–159.
[104] EnergyAustralia, *Revised regulatory proposal*, p. 195.

carve–out from the pricing criteria for prices which are regulated through other means (such as IPART's capital contribution determination or regulation of monopoly services).[105]

EnergyAustralia submitted that:[106]

- the AER's proposed NDSC and NCC do not comply with the transitional chapter 6 rules
- the AER's considerations should not be tied to its own limited regulatory precedent
- its proposed changes provide greater clarity for EnergyAustralia and users in entering into negotiated arrangements.

Integral Energy

Integral Energy accepted the draft decision.[107]

3.4 Submissions

Integral Energy

Integral Energy noted that the AER essentially adopted its proposed definition for negotiable components of direct control services in the draft decision.[108]

Integral Energy noted the concerns raised by EnergyAustralia in its revised regulatory proposal in relation to the AER's proposed definition of negotiable components of direct control services. Integral Energy submitted that there would be merit in amending the proposed definition to address a number of issues raised by EnergyAustralia including its contention that the third limb of the proposed definition is extremely broad and capable of capturing or impacting upon just about every aspect of connection services.[109]

Integral Energy submitted that the third limb of the proposed definition should be amended to make it clear that the only components of a connection service that are negotiable are those not covered by other regulatory instruments, such as IPART's capital contributions determination and the AER's monopoly services arrangements.[110]

EnergyAustralia

EnergyAustralia submitted that it supports Integral Energy's proposed revision to the definition of negotiable components of direct control services. EnergyAustralia supported Integral Energy in respect of the third limb of the definition but did not accept that the problem is limited to connection services. EnergyAustralia stated that there are ambiguities surrounding the use and application of the first two limbs which also require clarification. EnergyAustralia noted that Integral Energy's issue would be catered for within the definition proposed by EnergyAustralia.[111]

105 EnergyAustralia, *Revised regulatory proposal*, p. 194.
106 EnergyAustralia, *Revised regulatory proposal*, p. 195.
107 Integral Energy, *Revised regulatory proposal*, p. 88.
108 Integral Energy, *Submission to the AER*, p. 22.
109 Integral Energy, *Submission to the AER*, p. 22.
110 Integral Energy, *Submission to the AER*, p. 22.
111 EnergyAustralia, *Response to stakeholder submissions*, attachment, p. 29.

3.5 Issues and AER considerations

3.5.1 Negotiable components

In the draft decision, the AER defined a negotiable component of a direct control service as any component of a direct control service (or the terms and conditions on which that direct control service or component are provided) where:[112]

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

EnergyAustralia provided the AER with a number of examples to demonstrate that the proposed negotiable component definition is inadequate. Integral Energy proposed an amendment to the third limb of the definition to make it clear that the only components of the connection service that are negotiable are those not covered by other regulatory instruments.

The AER notes that part DA of the transitional chapter 6 rules only applies to negotiable components of direct control services. The AER also notes that for the NSW DNSPs in the next regulatory control period, customer funded connections are classified as an unregulated distribution service.[113] According to clause 6.2.3A of the transitional chapter 6 rules, unregulated distribution services are not direct control services. Therefore, customer funded connections cannot under their initial classification have negotiable components for the purposes of part DA of the transitional chapter 6 rules.[114] As a consequence, it is not necessary to amend the third limb of the AER's proposed definition to exclude customer funded connections.

For the NSW DNSPs in the next regulatory control period, monopoly services are classified as a direct control service and further classified as a standard control service.[115] Therefore, under the AER's proposed definition, there is the potential for monopoly services to have negotiable components which could include variations to prices for those services.[116] The AER notes that a regulated price has been set for monopoly services and

112 AER, *Draft decision*, section 3.7.
113 AER, *Final decision, New South Wales distribution determination 2009–10 to 2013–14*, 28 April 2009, section 2.7.
114 NER, transitional chapter 6 rules, clause 6.7A(b).
115 AER, *Final decision*, section 2.7.
116 NER, transitional chapter 6 rules, clause 6.7A.4.

considers it is not appropriate for those prices to be negotiable.[117] The AER has amended the definition of negotiable components to exclude monopoly services.

The AER notes that IPART's capital contributions and repayments determination establishes a framework for determining how much customers will be required to contribute towards the capital costs of connecting them to the electricity distribution network.[118] Clause 6.21.4(a) of the transitional chapter 6 rules provides that capital contribution charges by the NSW DNSPs in respect of the next regulatory control period are to be determined in accordance with IPART's capital contributions and repayments determination. EnergyAustralia and Integral Energy submitted that amounts which are determined under IPART's contributions and repayments determination should not be negotiable components.

The AER notes that IPART's capital contributions and repayments determination sets out how the capital contributions and repayments will be determined, and how disputes will be resolved. Therefore the AER considers that it is not appropriate for amounts which are determined under IPART's determination to be subject to an additional form of regulation as a negotiable component of a direct control service. Similarly, the AER is of the view that any regulatory instrument (other than this final decision and the final determination) that imposes requirements in relation to a component of a direct control service, should be excluded from the definition of negotiable components. The AER has amended the definition of negotiable components accordingly.

EnergyAustralia submitted that, in relation to the construction and maintenance of public lighting, a negotiable component of a direct control service should extend to the negotiable components of alternative control services to the extent that the AER's determination on control mechanisms allow.[119] In this final decision, the construction and maintenance of public lighting infrastructure is classified as a direct control service and further classified as an alternative control service.[120] Given that the construction and maintenance of public lighting infrastructure will be a direct control service, the AER is of the view that components of that service can be negotiable. The AER has decided, however, that prices and charges for the construction and maintenance of public lighting infrastructure can only be negotiated below (but not above) the prices and charges for the service which are set out in chapter 17 of this final decision.

EnergyAustralia submitted that part DA of the transitional chapter 6 rules is only intended to apply to components of services and not to whole services. EnergyAustralia noted that the expression 'connection service' is defined in the NER to include an entire multi–layered service. EnergyAustralia stated that this is the meaning that would be given to the expression 'connection service' in the third limb of the proposed definition.[121] The AER notes that it is not intended that the proposed definition results in a whole direct control service being a negotiable component. The preamble to the AER's proposed definition in the draft decision explicitly states that for something to be a negotiable component of a direct control service, it must be a component of the direct control service and the direct control service must satisfy one of three criteria. Relevantly, one of those

117 AER, *Final decision*, section 4.6.
118 IPART, *Capital contributions and repayments for connections to electricity distribution networks in New South Wales*, Final Report, Determination No 1 2002.
119 EnergyAustralia, *Regulatory proposal*, p. 179.
120 AER, *Final decision*, section 2.7.
121 EnergyAustralia, *Revised regulatory proposal*, pp. 158–159.

criteria is a certain type of 'connection service'. The AER notes that the criteria exclude certain aspects of direct control services from the definition. In addition, the negotiable component definition in this final decision excludes:

- requirements imposed by other regulatory instruments
- monopoly services
- most of the components of miscellaneous services and emergency recoverable works
- a price or charge for the alternative control service of the construction and maintenance of public lighting infrastructure which is above the price or charge set out in this final decision for that service.

EnergyAustralia also submitted that Integral Energy's suggested changes did not address the ambiguities surrounding the first two limbs of the definition.[122] The AER notes that the proposed negotiable components definition is based on the definition originally proposed by Integral Energy and has been modified in the light of submissions from Integral Energy and EnergyAustralia. The AER notes that the modifications to the proposed negotiable components definition apply to all three limbs of the definition.

Following the submission of the revised regulatory proposals, the AER provided the NSW and ACT DNSPs with an opportunity to comment on a revised draft of the negotiable component definition. The AER notes that ActewAGL, Country Energy and Integral Energy advised that the revised definition was acceptable.[123] EnergyAustralia, however, expressed concerns with the proposed definition and suggested further amendments.[124]

The AER has decided to make further amendments to the negotiable component definition to address EnergyAustralia's concerns. EnergyAustralia proposed that customer funded connections and customer specific services be expressly excluded from the definition.[125] As discussed above, the AER does not agree that it is necessary to expressly exclude customer funded connections because they are not direct control services. Similarly, it is not necessary to expressly exclude customer specific services because they have also been classified in this final decision as an unregulated distribution service (which is not a direct control service). In any event, if the AER did exclude customer funded connections and customer specific services from the definition, it could potentially limit the AER's discretion to subsequently re-classify the services as alternative control services (which is a subclass of direct control services) during the next regulatory control period. The AER can re-classify an unregulated distribution service as an alternative control service if the DNSP is not in substantial compliance with the relevant requirements of IPART's Regulation of Excluded Distribution Services Rule 2004/1 (see clauses 6.2.3B(b), (c) and (e) of the transitional chapter 6 rules). If during the next regulatory control period an unregulated distribution service is re-classified by the AER as an alternative control service then it can have components negotiated under the negotiable component regime for direct control services set out in part DA of the transitional chapter 6 rules. Those components could not be subsequently negotiated

122 EnergyAustralia, *Response to stakeholder submissions*, attachment, p. 29.
123 ActewAGL, email to the AER, 17 March 2009; Country Energy, email to the AER, 19 March 2009; and Integral Energy, email to the AER, 12 March 2009.
124 EnergyAustralia, Letter to the AER, 18 March 2009.
125 EnergyAustralia, Letter to the AER, 18 March 2009, p. 2.

under the negotiable component regime if the AER accepted EnergyAustralia's proposed amendment.

EnergyAustralia proposed extending exclusions from the definition to include non-price related terms and conditions of certain components.[126] The revised definition provided to the DNSPs only excluded price related terms and conditions of certain components. The AER has decided it would be appropriate for the exclusion to apply to price and non price related terms and conditions of certain components.

EnergyAustralia proposed an express exclusion from the definition for components forming part of any requirement imposed under part 3, division 4 of the *Electricity Supply Act 1995 (NSW).*[127] The AER agrees that these requirements should be excluded from the definition. However, since it is likely that there will be other regulatory instruments which should also be excluded (including regulatory instruments which are created during the next regulatory control period), the AER has decided to use the more general descriptor of 'regulatory instrument' for the exclusion. The AER has also decided to make the exclusion broader because it does not currently have before it any particular scenario for consideration. The AER notes that it interprets the expression 'regulatory instrument' to include, without limitation, any requirement imposed under part 3, division 4 of the *Electricity Supply Act 1995 (NSW).*

EnergyAustralia proposed that monopoly services, miscellaneous services and emergency recoverable works should be treated uniformly because there does not appear to be any room for negotiation of the price or non price aspects of these services.[128] The AER notes that section H.2(a) of appendix H of this final decision provides that the charges for miscellaneous services and emergency recoverable works can be negotiated below (but not above) the charges set out in sections H.3 and H.5 of appendix H, respectively. The AER has decided that the charges for miscellaneous services and emergency recoverable works can therefore be considered as a negotiable component but only for the purpose of negotiating those charges below the charges set out in this final decision. No other components of miscellaneous services and emergency recoverable works can be treated as a negotiable component.

EnergyAustralia noted that it had not been included in discussions between the AER and Integral Energy regarding the proposed definition, which occurred before the revised definition was provided to EnergyAustralia. As a consequence, EnergyAustralia stated that it was not aware of the extent to which the AER considered the matters raised by EnergyAustralia in its revised regulatory proposal or the AER's reasons for not adopting EnergyAustralia's proposed approach.[129]

The AER notes that it considered the matters raised by EnergyAustralia in its revised regulatory proposal. The AER first contacted Integral Energy about the proposed definition because the AER's proposed definition was based on the definition proposed by Integral Energy. All of the NSW DNSPs have been given the same opportunity as Integral Energy to comment on the revised definition.

126 EnergyAustralia, Letter to the AER, 18 March 2009, p. 2 and attachment.
127 EnergyAustralia, Letter to the AER, 18 March 2009, p. 2.
128 EnergyAustralia, Letter to the AER, 18 March 2009, p. 3.
129 EnergyAustralia, Letter to the AER, 18 March 2009, p. 1.

The AER notes that EnergyAustralia's proposed definition used very little of the language from the NER. The AER considers that wherever possible, it is important to use the language from the NER and limit deviations to providing necessary clarification. The AER's proposed negotiable component definition uses the language used in the NER—such as relevant expressions and concepts used in the definition of 'negotiated transmission service' in chapter 10 of the NER. This should enable customers to better identify which components of direct control services are negotiable. Further, using the language of the NER wherever possible should result in more consistent and better outcomes and greater transparency for customers.

EnergyAustralia noted that the negotiated transmission services criteria determined by the AER in its ElectraNet decision adopted the relevant principles from chapter 6A of the NER without any additional matters.[130] The AER notes the criteria determined in the ElectraNet decision contained the additional criterion that referred to the national electricity market objective.[131] EnergyAustralia stated in its regulatory proposal that it assumed the AER would take a similar approach in relation to EnergyAustralia's distribution determination.[132] The AER is following this approach for its proposed NDSC and NCC. However, in a subsequent submission on the proposed NDSC and NCC, EnergyAustralia sought a number of changes (including the removal of the criterion that referred to the national electricity market objective).[133] This is discussed further in the following section.

EnergyAustralia submitted that by applying the transmission negotiated service definition to the definition of negotiable components of direct control services, the AER has effectively reversed the MCE's decision.[134] EnergyAustralia relied on the following explanatory material produced by the MCE[135] to support its assertion:[136] '[t]he ACT and NSW DNSPs do not have negotiated distribution services'.[137] The AER does not consider it is possible to infer anything from this sentence about how negotiable components of direct control services should be defined or the applicability of the transmission regime to negotiable components. The only negotiated distribution service which EnergyAustralia provides relates to its transmission assets.

3.5.2 NDSC and NCC

Criterion 5 of the AER's proposed NCC provides that:

> [t]he price for a negotiable component must be the price for that component in the DNSP's approved pricing proposal, unless the terms and conditions sought for the component are so different from those used for the purposes of establishing the approved pricing proposal as to warrant determination of the price without regard to this criterion.

130 EnergyAustralia, *Regulatory proposal*, p. 215.
131 AER, *Final decision, ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008, p. 113, which adopts the approach in: AER, *Draft decision, ElectraNet transmission determination 2008–09 to 2012–13*, 9 November 2007, pp. 225–226 and Appendix H.
132 EnergyAustralia, *Regulatory proposal*, p. 215.
133 EnergyAustralia, *Submission on the AER's proposed NDSC and NCC*, 8 August 2008, pp. 2–3.
134 EnergyAustralia, *Revised regulatory proposal*, p. 158.
135 MCE, *Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution, Explanatory Material*, April 2007, p. 42.
136 EnergyAustralia, *Revised regulatory proposal*, p. 158.
137 MCE, *Explanatory material*, p. 42.

EnergyAustralia submitted that the AER's proposed NCC should be amended so that the price for a negotiable component need not be the price for that component in the DNSP's approved pricing proposal if that price is set under other regulatory instruments (e.g. IPART's capital contributions and repayments determination, regulation of charges for monopoly services and part 3, division 4 of the *Electricity Supply Act 1995* (NSW)). EnergyAustralia proposed a new criterion for the NCC to address this concern.[138]

The AER is of the view that it is not necessary to insert EnergyAustralia's proposed criterion in the NCC. The exclusion of amounts relating to IPART's capital contributions and repayments determination, monopoly services and part 3, division 4 of the *Electricity Supply Act 1995* (NSW) from the definition of negotiable component of direct control services means that it is not necessary to create a further carve–out in the price of services section of the NCC.

EnergyAustralia submitted that the AER's decision not to include all of the language from clauses 6.7.1(9) and 6.7A.1(10) of the transitional chapter 6 rules in criterion 2 of the NDSC and NCC creates confusion for negotiating parties, is incorrect and does not comply with the transitional chapter 6 rules because they do not give effect to the negotiated distribution service principles and negotiable component principles.[139] The AER notes that it has not included in criterion 2 the provision which deems prices to be fair and reasonable if they comply with the other price related principles (i.e. clauses 6.7.1(1) to (7) for the price for a negotiated distribution service and clauses 6.7A.1(1) to (8) for the price for a negotiable component).

The AER does not agree with EnergyAustralia's submission in relation to the above points. It is not necessary to amend the NDSC and NCC in this way because, relevantly, clauses 6.7.4(b) and 6.7A.4(b) of the transitional chapter 6 rules require the NDSC and NCC to give effect to and be consistent with the respective principles in clauses 6.7.1 and 6.7A.1 of the transitional chapter 6 rules. It is possible that when a DNSP negotiates terms and conditions of access a user will not accept, for example, that a price for a negotiable component is fair and reasonable even though it complies with clauses 6.7A.1(1) to (8) of the transitional chapter 6 rules. Relevantly, clause 6.7A.1(10) of the transitional chapter 6 rules states that the terms and conditions of access for a negotiable component should be fair and reasonable and the price for a negotiable component will be treated as such if it complies with clauses 6.7A.1(1) to (8) of the transitional chapter 6 rules. Whilst the AER has not included this price related deeming provision in criterion 2 of the NCC, a DNSP should simply inform users who will not agree with a price which the DNSP has set in accordance with the principles in clause 6.7A.1, that criterion 2 gives effect to clause 6.7A.1(10) and, as a consequence, the price is fair and reasonable because it complies with clauses 6.7A.1(1) to (8).

EnergyAustralia submitted that the AER is not obliged to be consistent with the approach adopted in previous determinations if cogent reasons have been put forward which justify departure from such an approach.[140] The AER notes, however, that EnergyAustralia originally submitted that it supported the AER adopting an approach similar to that adopted in the ElectraNet transmission determination.[141] The AER has properly

138 EnergyAustralia, *Revised regulatory proposal*, p. 195.
139 EnergyAustralia, *Revised regulatory proposal*, p. 197.
140 EnergyAustralia, *Revised regulatory proposal*, p. 198.
141 EnergyAustralia, *Regulatory proposal*, p. 215.

considered EnergyAustralia's submissions and is of the view that EnergyAustralia has not provided sufficient justifications for it to depart from the approach adopted in its previous transmission determinations.

EnergyAustralia submitted that criterion 1 of the NDSC and NCC is unclear, unnecessary and creates ambiguity in application. EnergyAustralia resubmitted that if criterion 1 is retained it should be made consistent with other references in the NEL (e.g. sections 16, 88 and 91A) so the requirement is to 'contribute to' the achievement of the national electricity objective, rather than to 'promote' it. [142] The AER does not agree with EnergyAustralia's submission for the reasons set out in the draft decision.[143]

As noted in the draft decision, the AER has relied on section 7 of the NEL for the source of the obligation.[144] The AER considers criterion 1 sets out a straight forward obligation and no amendment is necessary to enhance its meaning.

EnergyAustralia also submitted that the AER must give proper consideration to the application of the criterion to distribution and to the fact that there is a clear policy intention that the criteria should be developed by the AER as appropriate for each determination—otherwise the criteria would have been codified.[145] The AER has given proper consideration to the application of the criteria to the NSW DNSPs and is of the view that the NDSC and NCC are appropriate for this determination. The AER is a national regulator operating under a national regime. The different regulatory regimes which existed between the various states and territories constituted a substantial impediment to the development of a truly national energy market and resulted in significant costs being imposed on industry participants (with those costs typically being passed on to end users).[146] One of the reasons for the establishment of the national regime was to minimise the complexities for DNSPs associated with dealing with more than one regulator and differing interpretations of the rules.[147]

Similar reasoning can be applied to the customers of the DNSPs. From the customers' perspective, it would be preferable to only have to assess one set of criteria. If each DNSP had a different set of criteria, the customer would have to compare each criteria to ascertain the differences and then decide on the importance and effect of the differences. The AER considers it is important to maintain a consistent approach wherever possible, especially if it is in relation to customer negotiations, and has determined that it is appropriate for there to be one NCC which applies to the NSW DNSPs and ActewAGL and for the NDSC to apply to EnergyAustralia. The AER has not identified any reason for different versions of the NCC to apply to each DNSP.

The AER notes that when the NSW DNSPs submit their annual pricing proposals, the proposals must include any variations to prices charged for a negotiable component of direct control services which resulted from the application of the NCC.

142 EnergyAustralia, *Revised regulatory proposal*, p. 199.
143 AER, *Draft decision*, p. 31.
144 AER, *Draft decision*, p. 31.
145 EnergyAustralia, *Revised regulatory proposal*, p. 198.
146 MCE, *National Framework for electricity and gas distribution and retail regulation, Foreword and issues paper*, August 2004, p. 12 of issues paper prepared by Allens Arthur Robinson.
147 MCE, *Foreword and issues paper,* p. 12 of issues paper prepared by Allens Arthur Robinson.

3.6 AER conclusion

3.6.1 Negotiable components

The AER has defined a negotiable component of a direct control service as any component of a direct control service (including the terms and conditions on which that direct control service or component is provided) where:

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

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

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

but excludes in relation to any component of a direct control service:

(d) requirements imposed under a regulatory instrument (other than this final decision and the final determination);

(e) a component of monopoly services as defined in this final decision;

(f) a component of miscellaneous services or emergency recoverable works as defined in this final decision (other than a component which is the price or charge for that service where the price or charge is below (but not above) the price or charge set out in this final decision for that service);

(g) a price or charge for the alternative control service of the construction and maintenance of public lighting infrastructure which is above the price or charge set out in this final decision for that service.

Components that fall within the scope of the above definition, are negotiable components. The AER considers that this definition is consistent with the examples of potential negotiable components provided by the DNSPs and provides an appropriate framework under which ActewAGL and the NSW DNSPs can operate. This approach will apply to Country Energy even though it proposed not having any components of direct control services which are negotiable.

3.6.2 Negotiable component criteria

The NCC for the NSW DNSPs is set out in appendix B of this final decision.

3.6.3 EnergyAustralia negotiated distribution services

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

3.6.4 EnergyAustralia negotiated distribution service criteria

The NDSC for EnergyAustralia is set out in appendix C of this final decision.

3.6.5 Negotiating framework

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

3.7 AER decision

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

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

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

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

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

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

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

but excludes in relation to any component of a direct control service:

(d) requirements imposed under a regulatory instrument (other than this final decision and the final determination);

(e) a component of monopoly services as defined in this final decision;

(f) a component of miscellaneous services or emergency recoverable works as defined in this final decision (other than a component which is the price or charge for that service where the price or charge is below (but not above) the price or charge set out in this final decision for that service);

(g) a price or charge for the alternative control service of the construction and maintenance of public lighting infrastructure which is above the price or charge set out in this final decision for that service.

Note: Customer funded connections and customer specific services (as defined in this final decision) are classified as unregulated distribution services in chapter 2 of this final decision. According to clause 6.2.3A(a) of the transitional chapter 6 rules, an unregulated distribution service is not a direct control service. Therefore, unregulated distribution services cannot have negotiable components which are subject to part DA of the transitional chapter 6 rules. The AER notes that during the next regulatory control period, it is able to re-classify an unregulated distribution service as an alternative control service (which is a subclass of direct control services) if the DNSP is not in substantial compliance with the relevant requirements of IPART's Regulation of Excluded Distribution Services Rule 2004/1 (see clauses 6.2.3B(b), (c) and (e) of the transitional chapter 6 rules). If during the next regulatory control period an unregulated distribution service is re-classified by the AER as an alternative control service then it can have components negotiated under the negotiable component regime for direct control services set out in part DA of the transitional chapter 6 rules.

In accordance with clause 6.12.1(16B) and 6.7A.4(a) of the transitional chapter 6 rules the negotiable component criteria for the NSW DNSPs is at appendix B of this final decision.

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

4 Control mechanisms for direct control services

4.1 Introduction

A distribution determination imposes controls over the prices and revenues that a DNSP may recover from providing direct control services.

The AER published a guideline setting out the control mechanisms it proposed to apply to direct control services provided by the NSW DNSPs during the next regulatory control period.[148] For the NSW DNSPs' standard control services this mechanism is a weighted average price cap (WAPC).

This chapter sets out the AER's consideration of issues raised in response to the draft decision. It also sets out how the control mechanism will be applied and how the AER will determine compliance with the control mechanism during the next regulatory control period.

4.2 AER draft decision

In the draft decision the AER applied a WAPC to the NSW DNSPs' standard control services for the next regulatory control period.[149] The decision to use a WAPC was consistent with the AER's guideline on the control mechanisms for direct control services for the ACT and NSW 2009 distribution determinations.[150]

In specifying the WAPC, the AER also decided to apply a schedule of prices for miscellaneous and monopoly (MM) services (including emergency recoverable works) for the next regulatory control period.[151] The definitions of these services were set out in appendix G of the draft decision and the schedule of prices was set out in appendix H of the draft decision.

Further, the AER decided to apply a revenue cap to EnergyAustralia's prescribed (transmission) standard control services.[152]

4.3 Revised regulatory proposals

4.3.1 Country Energy

Country Energy raised no issues regarding the control mechanisms.

4.3.2 EnergyAustralia

EnergyAustralia raised the following issues with respect to the control mechanism for standard control services and related pricing issues:

148 AER, *Guideline on control mechanisms for direct control services for the ACT and NSW 2009 distribution determinations*, February 2008.
149 AER, *Draft decision*, section 4.6.
150 AER, *Guideline on control mechanisms ACT and NSW*.
151 AER, *Draft decision*, section 4.6.
152 AER, *Draft decision*, p. 57.

- the introduction of a G factor to the WAPC formula to reflect uncertainties in energy forecasts caused by the possible introduction of a Carbon Pollution Reduction Scheme (CPRS)
- the pricing of MM services
- the application of side constraints
- the treatment of transmission use of system (TUOS) recoveries.

G factor

EnergyAustralia stated that there had been significant developments in the implementation of a CPRS since the submission of its regulatory proposal. In particular, EnergyAustralia noted that the Government's White Paper was published in December 2008 and indicated that a CPRS will significantly increase electricity prices and lead to reduced energy consumption. EnergyAustralia considered that these developments have introduced an unprecedented level of uncertainty in the formulation of its demand forecasts. In response to these developments, EnergyAustralia proposed a G factor adjustment to the WAPC formula.[153]

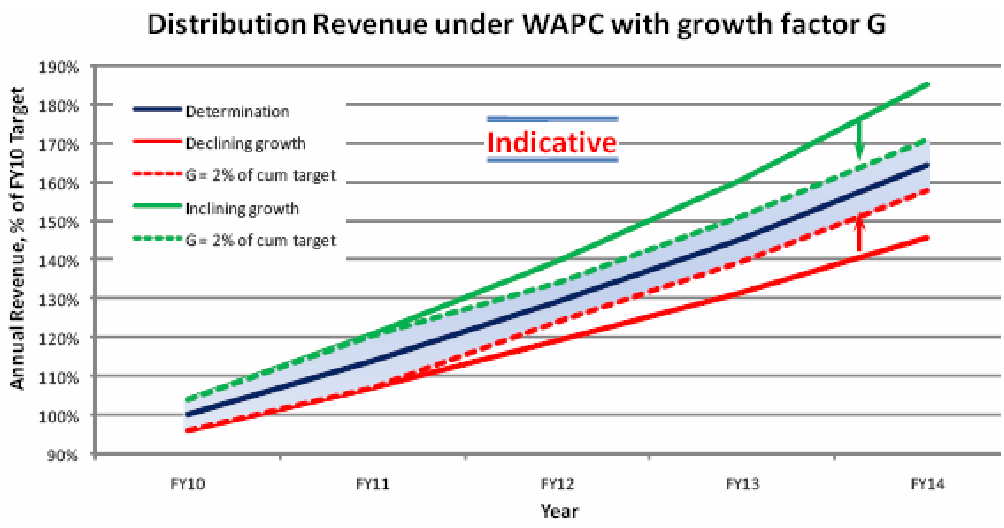
EnergyAustralia considered the current regulatory arrangements to be asymmetric in that they provide no relief for volume risk, but would allow relief by way of a pass through for the cost impacts of a CPRS.[154]

EnergyAustralia stated that it proposed the G factor as an alternative to including an adjustment in the demand forecasts to recognise the possible introduction of a CPRS. EnergyAustralia claimed that its forecasts did not include any adjustment for this matter and noted that the AER's consultants, McLennan Magasanik Associates (MMA), raised the issue of the effects of a possible CPRS in its final report in respect of demand and energy forecasts.[155]

In summary, the G factor proposed by EnergyAustralia was designed to limit the extent to which revenues can vary during the next regulatory control period for differences between forecast and actual demand.[156] EnergyAustralia illustrated the effect of the proposed G factor as allowing revenue to vary from that implicit in the AER's decision to within the shaded band as per figure 4.1.

[153] EnergyAustralia, *Revised regulatory proposal*, pp. 162–163.
[154] EnergyAustralia, *Revised regulatory proposal*, p. 163.
[155] EnergyAustralia, *Revised regulatory proposal*, pp. 162–164.
[156] EnergyAustralia, *Revised regulatory proposal*, pp. 162–164.

Figure 4.1: An example of the G factor in operation



Source: EnergyAustralia, *Revised regulatory proposal*, Attachment II.4B, p. 4.[157]

EnergyAustralia noted the G factor is not a fixed percentage. The extent to which revenues may vary from that included in the AER's final decision before the G factor is invoked depends on a percentage (L), which EnergyAustralia proposed that the AER determine.[158] Once this percentage is exceeded, prices would be adjusted either down or up by the G factor which would be calculated so that the revised revenues under the adjusted prices are expected to be within 'L' per cent of the forecast revenues at the time of the final decision.

Further details on the calculation of the G factor proposed by EnergyAustralia are presented in Attachment II.4B of its revised regulatory proposal.

EnergyAustralia considered the proposed variation to the control mechanism would still result in it being substantially the same as that used by IPART and therefore in accordance with clause 6.2.5 of the transitional chapter 6 rules. EnergyAustralia argued that to be 'substantially the same' the control mechanism must have the same 'essence' as that used by IPART. EnergyAustralia argued that its mechanism was still a WAPC and not a revenue cap or hybrid approach because prices would 'continue to be set based on established X-factors, together with other adjustments. These are the 'essence' of the mechanism.'[159]

In addition, EnergyAustralia argued that if volumes did not vary significantly from forecast, the G factor would not be triggered and the control mechanism would be no different from that applied to EnergyAustralia in the current regulatory control period.[160]

157 In figure 4.1 EnergyAustralia has incorrectly labelled the L percentage of 2 per cent as the G factor. The G factor is in fact represented in the figure by the two coloured arrows which indicate the distance between the respective solid and broken coloured lines.

158 EnergyAustralia, *Revised regulatory proposal*, pp. 163–164.

159 EnergyAustralia, *Revised regulatory proposal*, p. 164.

160 EnergyAustralia, *Revised regulatory proposal*, p. 164.

Pricing of miscellaneous services, monopoly services and emergency recoverable works

EnergyAustralia raised two concerns regarding the pricing of MM services. It stated that the AER had not:[161]

- made provision for the prices of MM services to be set at levels that recover EnergyAustralia's efficient costs
- considered the benefits of allowing more flexibility in pricing arrangements.

EnergyAustralia raised concerns that the AER may not have had sufficient time to undertake its analysis of the pricing of these services. It refered to a statement in the draft decision that suggested a more wide ranging investigation of the costs of these services is expected to be undertaken as part of the framework and approach process for the 2014–2019 distribution determination. EnergyAustralia considered that the NEL does not allow such an assessment to be deferred.[162]

EnergyAustralia claimed that inherent cross subsidisation still exists between the MM services and other standard control services and that this cross subsidisation will get worse under the AER's approach. EnergyAustralia claimed that the costs of providing the same number of MM services (excluding emergency recoverable works) in 2009–10 are 110 per cent higher than two years earlier.[163] In the draft decision, the AER allowed only a cumulative consumer price index (CPI) increase in the tariffs of these services over the same period, that is, no real cost increases.[164]

To achieve efficient prices, EnergyAustralia argued that the AER should adopt its proposal that these services be treated in a similar manner to other standard control services and remove the schedule of prices for these services. EnergyAustralia considered that the increased flexibility in pricing afforded by the adoption of its proposal will allow it to set efficient prices for these services. EnergyAustralia claimed that there is no reasonable basis for the AER rejecting its proposal.[165]

Application of the side constraints

In the draft decision, the AER rejected EnergyAustralia's proposed amendment to the expression of the X factor to account for the D–factor in the application of the side constraints. The AER noted that clause 6.18.6(d) of the transitional chapter 6 rules requires any price changes arising because of the D–factor (or other adjustments arising out of rules 6.6 or 6.13) to be disregarded when assessing compliance with side constraints. Accordingly, changing the X factor expression was considered by the AER to be unnecessary.[166]

In its revised regulatory proposal, EnergyAustralia argued that the AER could not rely on clause 6.18.6(d) and should be more explicit about how the D–factor is to be treated for

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161 EnergyAustralia, *Revised regulatory proposal*, pp. 165–166.
162 EnergyAustralia, *Revised regulatory proposal*, pp. 165–166.
163 EnergyAustralia, *Revised regulatory proposal*, p. 165, and attachment II.4C.
164 AER, *Draft decision*, section 4.5.
165 EnergyAustralia, *Revised regulatory proposal*, pp. 165–166.
166 AER, *Draft decision*, pp. 47–48.

the side constraints. EnergyAustralia asked, 'Must the D–factor be recovered on an equal percentage basis across all tariffs? What discretion does the DNSP have in this regard?'[167]

Recovery of transmission use of system costs

EnergyAustralia stated that the AER did not consider its regulatory proposal to maintain the approach adopted by IPART regarding the treatment of TUOS under and over recoveries.[168]

In the draft decision, the AER stated that it would require TUOS charges for a particular year to be set with regard to any under and over recoveries reported for the most recently completed regulatory year (that is, two regulatory years prior).[169] EnergyAustralia argued that this approach does not correctly apply clause 6.18.7(c) of the transitional chapter 6 rules which refers to recoveries in the previous regulatory year.[170] It also noted that the AER's approach, while consistent with its guideline,[171] represented a departure from that used by IPART without good reason. EnergyAustralia suggested the AER's approach would also result in larger variations in TUOS charges from year to year.[172]

4.3.3 Integral Energy

Integral Energy raised two matters with respect to the control mechanism for standard control services:[173]

- the application of the reasonable estimates approach in relation to the introduction of new time of use (ToU) tariff structures
- the introduction of feed–in–tariffs by the NSW Government.

Application of reasonable estimates approach

Integral Energy suggested that the AER reconsider whether the requirement under J.1(2) of appendix J of the draft decision should apply for the introduction of ToU tariffs.[174]

Integral Energy noted that when implementing a new tariff or tariff component, section J.1(2) requires the DNSP to assume that customers have the same consumption and load profile on the new tariff/tariff component as previously. This implies that the sum of the reasonable estimates for each unit of measure on the new network tariff/tariff component plus the reasonable estimates for each unit of measure on the origin network tariff/tariff component, equals the actual audited quantities that occurred for the origin network tariff/tariff component. Integral Energy considered that the reasonable estimate requirements under section J.1(2) will restrict the DNSP's ability to introduce innovative ToU energy tariffs and demand tariff structures. In particular, it was concerned that when a peak period tariff component was introduced:[175]

167 EnergyAustralia, *Revised regulatory proposal*, p. 167.
168 EnergyAustralia, *Revised regulatory proposal*, p. 191.
169 AER, *Draft decision*, pp. 48–49.
170 EnergyAustralia, *Revised regulatory proposal*, p. 192.
171 AER, *Guideline on control mechanisms ACT and NSW*.
172 EnergyAustralia, *Revised regulatory proposal*, p. 192.
173 Integral Energy, *Revised regulatory proposal*, pp. 89–91.
174 Integral Energy, *Revised regulatory proposal*, p. 89.
175 Integral Energy, *Revised regulatory proposal*, pp. 89–90.

- the volumes under the new peak period tariff component would be less than the volumes under the origin anytime tariff
- any increases in peak prices will cause reductions in quantities consumed during the peak period that are not matched by a pick up in quantities in other times of the day, resulting in an overall reduction in volumes compared to the volumes consumed under the previous anytime tariff.

Introduction of feed–in tariffs

Integral Energy stated that it had recently become aware that the NSW Government plans to introduce feed–in tariffs during the next regulatory control period. Integral Energy considered that any costs of such a scheme, including the payments made to customers who have exported energy back to the network at the mandated rate and metering configuration, should be outside the WAPC and side constraint formulas.[176]

4.4 Submissions

Country Energy

Country Energy stated that the draft decision treatment of TUOS under and over recoveries represented a departure from IPART's approach and may result in greater fluctuations in TUOS prices from year to year.[177]

Country Energy sought confirmation on its interpretation of the definition for the miscellaneous service of special meter reading. Country Energy suggested that it should be able to charge a customer for a special meter reading when it disconnects and reconnects premises that are holiday homes or the like (that is, where the occupant of the premises does not change during the process of disconnection/reconnection). Country Energy noted that it is common for this to occur four or more times a year for some premises. Country Energy stated that there is an incentive for customers to avoid the supply availability charge by disconnecting and reconnecting, because there is no charge for doing so. Country Energy submitted that this results in an unnecessary increase in its costs. Country Energy would like to ensure that the AER's final decision does not preclude it from applying a special meter reading fee in these circumstances.[178]

EnergyAustralia

EnergyAustralia agreed with the concern raised by Integral Energy regarding the introduction of new (higher) peak prices. When new peak prices are introduced there will be reductions in the quantities consumed during the peak period that are not matched by a pick up in quantities consumed at other times of the day. This will result in an overall reduction in demand compared to the demand recorded under the origin anytime tariff. However, EnergyAustralia did not share Integral Energy's concerns that when a new peak period tariff component was introduced the demand under the peak period tariff

176 Integral Energy, *Revised regulatory proposal*, pp. 90–91.
177 Country Energy, *Draft NSW distribution determination – draft decision*, 16 February 2009, p. 2.
178 Country Energy, Email to the AER, 20 February 2009.

component would be less than the demand under the origin anytime tariff. EnergyAustralia saw this as an interpretation issue.[179]

Integral Energy

Integral Energy supported the G factor as proposed by EnergyAustralia. Integral Energy suggested a reasonable range of between 2–5 per cent for the 'L' percentage, which it calculated to equate to between plus or minus \$16–40 million (in \$2009–10) in revenues.[180]

Integral Energy reiterated its concerns regarding the reasonable estimates approach when ToU tariffs are introduced, although it provided no further details on the examples highlighted in its revised regulatory proposal.[181]

Integral Energy also sought clarification regarding a discrepancy in the quantity lags used in the WAPC, as detailed in section 4.5 of the draft decision, and the quantity lags used in the reasonable estimates methodology, as detailed in appendix J of the draft decision. Integral Energy noted that the WAPC and side constraint formulas were calculated using quantities from year 't–2', however the reasonable estimates methodology detailed in appendix J used quantities from year 't–1'.[182]

Anglicare Sydney

Anglicare Sydney (Anglicare) raised concerns regarding the introduction of smart meters and ToU tariffs. Anglicare recommended that an analysis of ToU tariffs be undertaken by the AER, covering factors such as the ability of certain households to respond to ToU tariffs and the impacts of ToU tariffs on low income households. Anglicare also suggested that there needed to be an educational program for customers to accompany the introduction of ToU tariffs.[183]

4.5 Issues and AER considerations

4.5.1 NSW DNSPs' standard control services

Weighted average price cap

In the draft decision, the AER set out the following WAPC formula to apply to the NSW DNSPs' standard control services for the next regulatory control period:[184]

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

179 EnergyAustralia, *Submission on the AER's draft determination for other network service providers*, February 2009, p. 7.
180 Integral Energy, *Submission to the AER*, p. 21.
181 Integral Energy, *Submission to the AER*, pp. 24–25.
182 Integral Energy, *Submission to the AER*, p. 24.
183 Anglicare, *Submission in relation to energy prices and low income households, January 2009,* Addendum to the Anglicare Sydney submission, February 2009, pp. 1–2.
184 AER, *Draft decision*, pp. 55–56.

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

p_{ik}^{t} is the proposed price for component ‘k’ of the relevant tariff ‘i’ for year ‘t’

p_{ik}^{t-1} is the actual price for component ‘k’ of the relevant tariff ‘i’ for year ‘t–1’ (being the year which immediately precedes year ‘t’)

q_{ik}^{t-2} is the audited[185] quantity of component ‘k’ of the relevant tariff ‘i’ that was charged by the DNSP in year ‘t–2’ (being the year immediately preceding year ‘t–1’)

X_t is the allowed real change in average prices from year ‘t–1’ to year ‘t’ of the regulatory control period as determined by the AER

D_t is the demand management cost recovery factor for year ‘t’ calculated to recover certain approved demand management implementation costs and foregone revenue incurred in year ‘t–2’[186]

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

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

Where:

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

‘t’ refers to a nominal year

CPI month (year) means the CPI for the quarter and the year indicated.

While no DNSP raised it as an issue in response to the draft decision, the AER has decided for presentational purposes that it will add an explicit qualitative term to the equation above for any approved cost pass throughs. The revised WAPC is set out at section 4.6 of this final decision.

185 AER, *Final decision: Control mechanisms for direct control services for the ACT and NSW 2009 distribution determinations*, February 2008, p. 11.

186 AER, *Final decision: Demand management incentive schemes for the ACT and NSW 2009 distribution determinations*, February 2008, appendix C. In the draft decision the AER decided to apply the D-factor scheme as applied by IPART in its 2004 determination. In the draft decision it was stated the calculation of the D-factor term in the WAPC was set out in IPART, *NSW Electricity Distribution Pricing Final Report*, June 2004, p. 99.

G factor

The AER considers that EnergyAustralia's proposed introduction of a G factor adjustment to the control mechanism constitutes new information that can not be considered by the AER at this stage of the distribution determination process. Specifically, clause 6.10.3(a) of the transitional chapter 6 rules allows a DNSP to submit a revised regulatory proposal to the AER within 30 business days following the publication of the draft determination. Clause 6.10.3(b) states that a DNSP's revised regulatory proposal must only make revisions so as to incorporate the substance of any changes required to address matters raised by the draft determination or the AER's reasons for it. EnergyAustralia's proposal relating to the introduction of a G factor may be a consequence of the timing of specific recent developments but nevertheless moves beyond the considerations in the draft decision.

Contrary to EnergyAustralia's claims, the AER considers that the proposed G factor will also substantially alter the form of control mechanism. The G factor would restrict revenue variations and as such would change the form of control, in substance, from a price cap to a 'hybrid' mechanism. Determining the form of control was the subject of the AER's final decision on the control mechanisms for direct control services for the ACT and NSW 2009 distribution determinations, published in February 2008.[187]

Application of reasonable estimates

The AER has considered the concerns raised by Integral Energy regarding the introduction of ToU tariffs and the application of the reasonable estimates approach. Regarding Integral Energy's first concern, the AER agrees with EnergyAustralia that this concern appears to be an interpretation issue. When a new peak period tariff component is introduced, the reasonable estimates approach requires actual quantities under the origin anytime tariff to equal the sum of the reasonable estimates for both the new peak period tariff component and the new off–peak period tariff component. For example, the AER would not expect the actual quantities for the origin anytime tariff to match the reasonable estimates for the new peak period tariff component alone.

The AER has also considered Integral Energy's argument (supported by EnergyAustralia) that the introduction of ToU tariffs will lead to an overall reduction in consumption and that using reasonable estimates based on historical totals is therefore inappropriate. Integral Energy considered that such an outcome provides a disincentive to introduce potentially efficient ToU prices as revenues could be reduced by having prices set on the basis of higher historical quantities.

Integral Energy presented no details on the structure of the ToU tariff it trialled and noted its analysis was preliminary.[188] Therefore the AER has no basis on which to judge the outcomes observed by Integral Energy in its trial.

In general terms, however, the AER notes that the reasonable estimates approach is designed to deal with a variety of tariff restructuring scenarios. While the restructuring of tariffs will necessarily alter consumption patterns, the DNSPs have discretion as to how the tariffs are to be restructured and can therefore manage the quantity effects of raising or lowering tariffs/tariff components. This approach is consistent with incentive

[187] AER, *Final decision: Control mechanisms for direct control services*.

[188] Integral Energy, *Revised regulatory proposal*, p. 90.

regulation. The AER also notes that the quantity weights in the WAPC are updated annually, so any effect of using historical weights in the WAPC on incentives will only be temporary.

The AER appreciates that when introducing ToU tariffs, these tariffs can be designed in a variety of ways which may be more or less efficient in terms of price signalling for customers. Under the reasonable estimates approach, each possible ToU tariff design will also temporarily affect the revenues a DNSP can earn. Whether the effect is positive or negative for a DNSP is not certain and will depend on a number of factors, including:

- the degree of price changes introduced by the DNSP for the different periods of the day[189]
- how customers respond to the price changes, which will reflect their price elasticity of demand[190]
- the historical quantities consumed during each period of the day, which provide the basis from which the magnitude of the effects of the price changes can be assessed.[191]

The AER notes Anglicare's submission on the introduction and trialling of ToU tariffs and smart meters. In its submission, Anglicare recommended that ToU tariffs be reviewed and closely monitored to ensure that excessive price increases do not occur. Anglicare also recommended that any full implementation of smart meters be accompanied by a state wide education campaign to ensure all households are made aware of how to minimise electricity use at peak times.[192]

Besides tariff design and implementation considerations, the AER notes that there could be broader factors, such as general market conditions, that could explain the outcomes observed during Integral Energy's trial. Integral Energy did not provide any evidence to suggest it had considered such broader factors in explaining the preliminary results of its trial.

Based on the considerations above, the AER does not consider it appropriate to make an asymmetric adjustment to the reasonable estimates approach, an adjustment that assumes overall consumption will fall when ToU tariffs are introduced. The AER is not convinced that the reasonable estimates approach unduly restricts a DNSP's ability to introduce innovative tariff structures. The AER notes that the NSW DNSPs will be required to demonstrate the appropriateness of their tariff structures against clauses 6.18.2(b) and 6.18.5(b) of the transitional chapter 6 rules as part of their annual price approval process.

In response to Integral Energy's request for clarification of the quantity lags used in the draft decision, the AER has revised appendix J to make the application of the reasonable estimates clearer. For example, the time period notations in appendix J of this final decision have been made consistent with the time period notations referred to in the WAPC detailed in section 4.6 of this chapter.

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189 For example, the effects on overall quantities of an approach that raised peak period charges and held charges constant at other periods of the day could be quite different from an approach that raised peak period charges and reduced charges at other periods of the day.

190 A consumer's price elasticity of demand may also differ during different periods of the day.

191 These quantities also depend on the time period definitions. For example, the shorter the peak period of the day, other things being equal, the lower the quantities that will be consumed during the peak period.

192 Anglicare, *Submission,* addendum, pp. 1–2.

Introduction of feed–in tariffs

The AER notes Integral Energy's concern that feed–in tariffs may be introduced in NSW during the next regulatory control period. If this occurs, the AER considers that the NSW DNSPs can apply to recover the costs of these feed in tariffs using the cost pass through provisions in accordance with the transitional chapter 6 rules.

Application of the side constraints

In the draft decision, the AER proposed the following side constraint formula for each tariff class of standard control services provided by the NSW DNSPs:

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

Where: The tariff class has up to m components:

d_k^t is the proposed price for component 'k' of the tariff class for year 't'

d_k^{t-1} is the price charged by the DNSP for component 'k' of the tariff in year 't–1'

q_k^{t-2} is the audited quantity of component 'k' of the tariff that was charged by the DNSP in year 't–2'

L_t is the permissible real percentage change in the expected weighted average revenue of a tariff class from year 't–1' to year 't' of the regulatory control period, determined in accordance with clause 6.18.6 (c) of the transitional chapter 6 rules

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

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

Where:

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

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

The AER has reviewed EnergyAustralia's arguments regarding the application of the side constraints in relation to the D–factor and the need for the AER to clarify how the D–factor will be accounted for in the side constraints. The AER considers that this is best done by expanding the expression L_t contained in its side constraint formula (not to be confused with the ‘L’ percentage used by EnergyAustralia in its G factor proposal), rather than adopting EnergyAustralia’s approach of developing an adjusted X factor.

By expanding the L_t term the AER considers that all factors (those under clauses 6.18.6(c) and 6.18.6(d) of the transitional chapter 6 rules) affecting the application of the side constraint will be made apparent. In contrast, EnergyAustralia’s proposal would not achieve such clarity and would require changes not only to the side constraint formula but also the WAPC formula.

The AER has expanded upon its expression of L_t in its side constraint formula as follows:

$$L_t = (1 - X_t) \times (1 + D_t) \times (1 + 2\%) \pm (\text{pass through}_t)$$

Where;

X_t	is the allowed real change in average prices from year ‘t–1’ to year ‘t’ of the regulatory control period as determined by the AER. If X>0, then X will be set equal to zero for the purposes of the side constraint formula.
D_t	is the demand management cost recovery factor for year ‘t’ calculated to recover certain approved demand management implementation costs and foregone revenue incurred in year ‘t–2’.[193]
Pass through_t	is any cost pass through amount with respect to year t approved by the AER. The cost pass through factor is expressed in qualitative terms as the magnitude of this factor is variable and event dependent in nature.

The complete side constraint formula is set out in section 4.6 of this final decision.

Miscellaneous services, monopoly services and emergency recoverable works

Inclusion in the WAPC

In the draft decision, the AER rejected EnergyAustralia’s proposal to include the prices for MM services under the WAPC in the same manner as network tariffs. IPART’s approach of determining a schedule of prices for MM services was retained by the AER and a revised schedule of prices set out in appendix H of the draft decision.

The AER adopted substantially the same approach as IPART to the escalation of MM prices. The schedule of prices in IPART’s 2004 determination was escalated to take into account CPI movements over the current regulatory control period and an estimate for CPI movements in the next regulatory control period. (The forecast estimate of CPI was to be updated to reflect actual CPI at the time of the AER’s final decision). A P_0 adjustment was also applied so fixed prices for these services could be set for the duration of the next regulatory control period. The P_0 adjustement was calculated to achieve net present value (NPV) neutrality between the expected revenues when fixed tariffs are used

193 In this final decision the AER has decided to apply the D-factor scheme as applied by IPART in its 2004 determination. The calculation of the D-factor is set out in appendix K of this final decision.

for the entire regulatory control period and the expected revenues under all alternative tariff structures that could have been used such as increasing prices over time.

After considering EnergyAustralia's revised regulatory proposal, the AER accepts that there may be some prices for MM services that are currently not fully cost reflective or may become less cost reflective over the course of the next regulatory control period. This knowledge was implicit in the draft decision to undertake a review of the pricing of MM services as part of the framework and approach process for the 2014–2019 regulatory control period. In the draft decision, the AER noted that there were time constraints preventing a detailed assessment of the pricing of MM services across all the NSW DNSPs and ActewAGL. This situation has not changed and there is also no opportunity to consult with interested parties on any change of approach. Accordingly, the AER reiterates its decision to look more closely at the pricing of MM services for the 2014–2019 regulatory control period.

Notwithstanding the above, the AER does not accept EnergyAustralia's argument that the draft decision on this matter would result in significant cross subsidisation between the prices of MM services and network tariffs. As the weighting of the prices of MM services in the WAPC is relatively small (MM services contribute approximately 5 per cent to network revenues), even if the MM services were significantly underpriced (which has not been determined), there would be no (or extremely limited) distortion to the efficient consumption patterns of customers on network tariffs.

Consistent with the draft decision, the AER rejects EnergyAustralia's proposal that MM services be treated similarly to network tariffs under the WAPC. While the prices of MM services form (a fixed) part of the WAPC, the dynamic aspects of the WAPC and side constraints are based on factors affecting network tariffs, not the prices of MM services. For example, the D–factor that affects network tariffs has no relevance to the pricing of MM services. Accordingly, it would be inappropriate to treat MM services as though they were determined by the same factors as network tariffs. Given the relatively small weighting of MM services in the WAPC, there would also be very limited constraint on the movement of the prices of MM services under EnergyAustralia's proposal, effectively making control of these services redundant.

The AER also notes the requirement under clause 6.2.5(c1) of the transitional chapter 6 rules that the control mechanism for standard control services for the next regulatory control period be substantially the same as determined by IPART in its 2004 determination. The AER also considers there are benefits to consumers in terms of price certainty, in having a schedule of prices for MM services fixed for the next regulatory control period.

Costs of miscellaneous services, monopoly services and emergency recoverable works

The AER has given further consideration to the movement in the underlying costs of MM services. The AER does not consider it reasonable that EnergyAustralia's real costs of service provision could more than double in two years (noting EnergyAustralia's claim that this doubling occurred without any change in the volume of services provided). However, the AER accepts there has been some real cost increases in MM services over the current regulatory control period and that there are expected to be real cost increases for these services over the next regulatory control period. This position is also reflected in the AER's approach to determining the NSW DNSPs' capex and opex allowances which include real cost escalators. Accordingly, while the AER has not changed IPART's general approach to determining the prices of MM services, it has decided to add a real cost escalator to the CPI escalator already factored into the prices of MM services set out in the draft decision.

In the draft decision, the AER rejected Country Energy's proposal to adopt a labour cost escalator in addition to CPI. However, based on its further considerations, the AER has decided that using a real labour cost escalator (the same real labour cost escalator as that used to determine the NSW DNSPs' capex and opex allowances) for the pricing of MM services is appropriate. While the AER recognises that some MM services may have other cost components, such as materials or travel costs, it appears that labour costs are generally the largest (often 100 per cent) cost component of these services. Accordingly, the AER considers it reasonable for current purposes to assume that 100 per cent of the costs of the MM services are labour related.

The AER has decided that the real labour cost escalator will be applied to the prices of MM services from 1 July 2004, the commencement of the current regulatory control period. The AER does not consider it appropriate to go back further than this date, as IPART would have considered the need to change its approach as part of its 2004 determination and clearly decided to continue with its previous approach of indexing the prices of MM services by CPI only. However, the AER considers that more recent real labour cost increases (as well as expected real labour cost increases over the next regulatory control period) can and should be recognised.

In summary, compared to the prices for MM services contained in the draft decision, the prices in appendix H of this final decision have been revised to reflect both a revised CPI estimate (based on most recent actuals) and the addition of a real labour cost escalator for the period 1 July 2004 to 30 June 2014. The general approach to calculating the prices of MM services is otherwise unchanged from that detailed in the draft decision.

Definition of special meter reading service

The AER considers that the miscellaneous service of special meter reading includes disconnecting and reconnecting premises that are holiday homes or the like, where the retail customer associated with the premises does not change during the process of disconnection/ reconnection. The AER notes that in its determination for the current regulatory control period IPART abolished the account establishment fee which applied whenever a customer moved into new premises.[194] Country Energy submitted that with the abolition of the fee, some customers are abusing the framework to avoid the service availability charge by disconnecting their holiday homes when they are not being occupied. Country Energy submitted that often these homes are in remote areas requiring travelling time of an hour or more so staff can perform the disconnection or reconnection—this can occur out of hours at overtime rates in order to comply with regulatory obligations—driving unnecessary cost increases.[195] In these circumstances, the AER considers that Country Energy's approach is reasonable provided discretion is exercised in deciding when it is appropriate to charge for the special meter reading. The AER notes that section 2.5.2 of this final decision discusses the role of the Energy & Water Ombudsman NSW in resolving disputes between small retail customers and DNSPs.

[194] IPART, *NSW Electricity Distribution Pricing Final Report*, p. 115.
[195] Country Energy, email to the AER, 20 February 2009.

Definition of miscellaneous services, monopoly services and emergency recoverable works

The definitions of miscellaneous services, monopoly services and emergency recoverable works, which the AER outlined in appendix H of its draft decision remain the same and are as follows:

- miscellaneous services are the services identified in section G.1 of appendix G of this final decision
- monopoly services are the services identified in section G.2 of appendix G of this final decision
- emergency recoverable works are the works identified in section G.3 of appendix G of this final decision.

Recovery of transmission use of system costs

The AER notes that EnergyAustralia's proposal relating to the timing of TUOS recoveries did not present any new information beyond that considered by the AER at the time of its final decision and guideline relating to the control mechanisms.[196] As a result the AER did not discuss this issue in the draft decision.

In developing the guideline relating to the control mechanisms the AER indicated a preference to provide for a complete adjustment of under or over recoveries in a single year, rather than over multiple years. In doing so, the AER focused on the practicalities of not being able to know the value of recoveries in the regulatory year prior to that for which prices are being set, due to the timing of the pricing approval process. Hence, the AER's guideline and draft decision only envisaged the use of actual data for the most recently completed regulatory year which could be verified and audited, rather than a combination of actual and estimated data for two (or potentially more) prior regulatory years under the IPART approach. Arguably clause 6.18.7(c) of the transitional chapter 6 rules requires the value of the pass through to be based on an estimate of the previous regulatory year's under or over recovery. However this is almost certain to result in inappropriate windfall gains and losses for users and DNSPs.

In relation to EnergyAustralia's and Country Energy's comments that the draft decision treatment of TUOS under and over recoveries represented a departure from IPART's approach, the AER has re–examined its justification for departing from IPART's approach.[197] This justification was based on the desirability of using actual, verifiable data only and avoiding the use of estimates. On further consideration of the issue, the AER considers this is only a material consideration when assessing data used to calculate the WAPC where this data impacts on prices and revenues. By contrast, any errors in the data reported for TUOS pass throughs (including estimates) are able to be corrected. For this reason the AER has decided to continue with the current approach developed by IPART, which includes an estimate of recoveries in the year immediately prior to that for which prices are set. The requirements relating to the reporting of TUOS under and over recoveries are in appendix I of this final decision, which also contains an example calculation of the TUOS unders and overs account.

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196 AER, *Final decision: Control mechanisms for direct control services*.
197 AER, *Final decision: Control mechanisms for direct control services*.

Demonstration of compliance with the WAPC

In the draft decision the AER determined that it would continue IPART's requirements in relation to the auditing of quantity data, TUOS charges and reasonable estimates for the purposes of demonstrating compliance with the WAPC. The AER's consideration of TUOS charges and reasonable estimates for this final decision are detailed above.

The requirements in relation to various data used in demonstrating compliance with the WAPC for this final decision are contained in appendices A, G, H, I, J and K of this final decision.

4.5.2 EnergyAustralia prescribed transmission services

In the draft decision, the AER set out the following revenue cap formula for EnergyAustralia's prescribed (transmission) standard control services:[198]

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

Where:

MAR_t	=	the maximum allowed revenue;
AR_t	=	the allowed (smoothed) revenue;
S_{ct}	=	the service standards factor;
t	=	the time period on a regulatory (financial) year basis
ct	=	the time period on a calendar year basis.

Revenue decrements or increments arising out of the AER's service target performance incentive scheme (STPIS) would only be applied as a result of performance in the current regulatory control period.

For the final decision, the AER has clarified the calculation of the maximum allowed revenue (MAR) as it relates to EnergyAustralia's STPIS which will be measured on performance until 30 June 2009, and will cease to impact on revenues after 30 June 2011. The formulae for these calculations are outlined in section 4.6.

4.6 AER conclusion

As part of its pricing proposal, each of the NSW DNSPs must submit to the AER proposed tariffs and charging parameters which correspond to the price terms contained in the WAPC and side constraint equations set out below. Each of the relevant percentage factors (for example, the X factor, D–factor, CPI) must be rounded to two decimal places before being applied in the WAPC and side constrant forumlas. The schedule of prices for MM services is set out in appendix H of this final decision, while further details on EnergyAustralia's revenue cap for prescribed (transmission) standard control services are provided in chapter 16 of this final decision.

198 AER, *Draft decision*, p. 57.

Weighted average price cap

The AER has decided to apply a WAPC to the NSW DNSPs' standard control services for the next regulatory control period:

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

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

p_{ik}^{t} is the proposed price for component 'k' of the relevant tariff 'i' for year 't'

p_{ik}^{t-1} is the actual price for component 'k' of the relevant tariff 'i' for year 't–1' (being the year which immediately precedes year 't')

q_{ik}^{t-2} is the audited[199] quantity of component 'k' of the relevant tariff 'i' that was charged by the DNSP in year 't–2' (being the year immediately preceding year 't–1')

X_t is the allowed real change in average prices from year 't–1' to year 't' of the regulatory control period as determined by the AER

D_t is the demand management cost recovery factor for year 't' calculated to recover certain approved demand management implementation costs and foregone revenue incurred in year 't–2'[200]

Pass through$_t$ represents approved pass through amounts (expressed in percentage form) with respect to regulatory year 't' as determined by the AER under clause 6.6 of the transitional chapter 6 rules and chapter 15 of this final decision.

ΔCPI_t means the number derived, with respect to regulatory year 't', from the application of the following formula:

$$\Delta CPI_t = \frac{CPI_{March(t-2)} + CPI_{June(t-2)} + CPI_{September(t-1)} + CPI_{December(t-1)}}{CPI_{March(t-3)} + CPI_{June(t-3)} + CPI_{September(t-2)} + CPI_{December(t-2)}} - 1$$

Where:

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199 AER, *Final decision: Control mechanisms for direct control services*, p. 11. The AER will liaise with the NSW DNSPs prior to submission of their pricing proposals for the 2010–11 regulatory year regarding auditing requirements.

200 In this final decision the AER has decided to apply the D-factor scheme as applied by IPART in its 2004 determination. The calculation of the D-factor is set out in appendix K of this final decision.

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

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

Side constraint

The side constraint formula to apply to the NSW DNSPs:

$$\frac{\sum_{k=1}^{m} d_k^t \times q_k^{t-2}}{\sum_{k=1}^{m} d_k^{t-1} \times q_k^{t-2}} \leq (1+\Delta CPI_t)\times(1\text{-}X_t)\times(1+D_t)\times(1+2\%)\pm(\text{pass through}_t) \qquad \text{k} = 1,\ldots,\text{m.}$$

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

d_k^t is the proposed price for component 'k' of the tariff class for year 't'

d_k^{t-1} is the price charged by the DNSP for component 'k' of the tariff in year 't–1'

q_k^{t-2} is the audited quantity of component 'k' of the tariff that was charged by the DNSP in year 't–2'

X_t is the allowed real change in average prices from year 't–1' to year 't' of the regulatory control period as determined by the AER. If X>0, then X will be set equal to zero for the purposes of the side constraint formula.

D_t is the demand management cost recovery factor for year 't' calculated to recover certain approved demand management implementation costs and foregone revenue incurred in year 't–2'[201]

Pass through$_t$ represents approved pass through amounts (expressed in percentage form) with respect to regulatory year 't' as determined by the AER under rule 6.6 of the transitional chapter 6 rules and chapter 15 of this final decision.

ΔCPI_t means the number derived, with respect to regulatory year 't', from the application of the following formula:

$$\Delta CPI_t = \frac{CPI_{March(t-2)} + CPI_{June(t-2)} + CPI_{September(t-1)} + CPI_{December(t-1)}}{CPI_{March(t-3)} + CPI_{June(t-3)} + CPI_{September(t-2)} + CPI_{December(t-2)}} - 1$$

[201] In this final decision the AER has decided to apply the D-factor scheme as applied by IPART in its 2004 determination. The calculation of the D-factor is set out in appendix K of this final decision.

Where:

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

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

Maximum allowable revenue (EnergyAustralia's prescribed (transmission) standard control services)

The AER has decided to apply a revenue cap to EnergyAustralia's prescribed (transmission) standard control services.

The MAR for the first year will be set equal to the allowed revenue (AR) for the first year of the regulatory control period:

MAR_1 = AR_1

where:

MAR_1 = the maximum allowed revenue for year 1 (i.e. 2009–10)

AR_1 = the allowed revenue for year 1, as calculated in chapter 16 of this final decision

The value of MAR for subsequent years of the regulatory control period requires adjusting the previous year's AR for inflation and the X factor:

$AR_t = AR_{t-1} \times (1 + \Delta CPI_t) \times (1 - X_t)$

where:

AR_t = the allowed (smoothed) revenue

t = time period/financial year (for t = 2, 3, 4, 5)

ΔCPI_t = the annual percentage change in the ABS Consumer Price Index All Groups, Weighted Average of Eight Capital Cities from March in year 't – 2' to March in year 't – 1'

X_t = the X factors for EnergyAustralia's prescribed (transmission) standard control services, as determined by the AER in chapter 16 of this final decision.

The MAR is then determined by adjusting the AR for any pass through amounts and incentive payments under the AER's STIPS:

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

Where:

MAR_t = the maximum allowed revenue;

AR_t = the allowed (smoothed) revenue

S_{ct} = the service standards factor. The value of S_{ct} for calendar year 2009 will be calculated on transmission service standards performance up to and including 30 June 2009. The value of S_{ct} with respect to calendar years after 2009 will be zero;

t = the time period on a regulatory (financial) year basis; and

ct = the time period on a calendar year basis.

To accommodate the transitional impact of the STPIS ceasing to apply to performance from the middle of calendar year 2009, the MAR for the 2010–11 regulatory year will be calculated as follows:

$$MAR_{2010-11} = AR_{2010-11} \pm \left[\frac{AR_{2008-09}}{2} \times S_{2009} \right] \pm (\textit{pass through})$$

4.7 AER decision

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the control mechanism for standard control services provided by the NSW DNSPs is a weighted average price cap. The applicable formulas are set out in section 4.6 of this final decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the NSW DNSPs' miscellaneous services, monopoly services and emergency recoverable works for the next regulatory control period are set out in appendix G of this final decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the schedule of fees and charges for the NSW DNSPs' miscellaneous services, monopoly services and emergency recoverable works for the next regulatory control period are set out in appendix H of this final decision.

In accordance with clause 6.12.1(19) of the transitional chapter 6 rules the NSW DNSPs must submit, as part of their annual pricing proposal, a record of the amount of revenues recovered from TUOS charges and associated payments in accordance with appendix I of this final decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the control mechanism for EnergyAustralia prescribed (transmission) standard control services is set out in section 4.6 of this final decision.

In accordance with clause 6.12.1(13) of the transitional chapter 6 rules the NSW DNSPs must demonstrate compliance with the standard control services control mechanism in accordance with appendices A, G, H, I, J and K of this final decision.

5 Opening regulatory asset base

5.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision. It sets out the method used by the AER to determine the closing regulatory asset base (RAB) for each NSW DNSP for the current regulatory control period. The closing RAB becomes the opening RAB for the next regulatory control period and is used to calculate the annual building block revenue requirements.

5.2 AER draft decision

5.2.1 Country Energy

The RAB roll forward calculations for Country Energy are set out in table 5.1 and result in an opening RAB of $4247 million for the next regulatory control period (as at 1 July 2009).

Table 5.1: AER draft decision on Country Energy's opening RAB ($m, nominal)

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

Source: AER, *Draft decision*, p. 79.

The AER decided that the opening RAB should not include omitted assets as proposed by Country Energy. Accordingly, the proposed amount of $296 million was not included in the opening RAB as at 1 July 2009. The AER noted it would update the roll forward of Country Energy's RAB with actual capex for 2007–08, the most recent forecast of capex for 2008–09, and the latest actual CPI data at a time closer to its final distribution determination.[202]

[202] AER, *Draft decision*, pp. 79–80.

5.2.2 EnergyAustralia

The RAB roll forward calculations for EnergyAustralia are set out in tables 5.2 and 5.3, and result in a distribution opening RAB of $7203 million and a transmission opening RAB of $985 million for the next regulatory control period (as at 1 July 2009). The combined distribution and transmission opening RAB as at 1 July 2009 is $8188 million. The AER noted it would update the roll forward of EnergyAustralia's RAB with actual capex for 2007–08, the most recent forecast of capex for 2008–09, and the latest actual CPI data at a time closer to its final distribution determination.[203]

Table 5.2: AER draft decision on EnergyAustralia's opening RAB (distribution) ($m, nominal)

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

Source: AER, *Draft decision*, p. 80.

203 AER, *Draft decision*, p. 80.

Table 5.3: AER draft decision on EnergyAustralia's opening RAB (transmission) ($m, nominal)

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

Source: AER, *Draft decision*, p. 81.

5.2.3 Integral Energy

The RAB roll forward calculations for Integral Energy are set out in table 5.4 and results in an opening RAB of $3678 million for the next regulatory control period (as at 1 July 2009).

Table 5.4: AER draft decision on Integral Energy's opening RAB ($m, nominal)

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

Source: AER, *Draft decision*, p. 82.

The AER decided not to approve Integral Energy's proposed increase to the opening RAB of $170 million for asset lives used in the historical valuation of sub–transmission and zone substations. The AER noted it would update the roll forward of Integral Energy's RAB with actual capex for 2007–08 and the most recent forecast of capex for 2008–09, and the latest actual CPI data at a time closer to its final distribution determination.[204]

5.2.4 RAB roll forward for the 2014–19 regulatory control period

The AER stated it would use actual depreciation to establish the opening RAB for the 2014–19 regulatory control period.[205]

5.3 Revised regulatory proposals

5.3.1 Country Energy

Country Energy accepted the draft decision and provided an updated value of actual capex for 2007–08.[206]

5.3.2 EnergyAustralia

EnergyAustralia accepted some aspects of the draft decision but did not accept:[207]

- that EnergyAustralia's method of calculating inflation was inconsistent with the NER
- the decision to use actual rather than forecast depreciation in establishing the opening RAB for the 2014–19 regulatory control period.

In its revised regulatory proposal EnergyAustralia provided an updated value of actual capex for 2007–08. EnergyAustralia also replaced the estimate of inflation for 2007–08 in its regulatory proposal with actual inflation, and updated the inflation estimate used for 2008–09 with the latest available CPI data based on its proposed method.[208]

5.3.3 Integral Energy

Integral Energy accepted the AER's adjustments to the RAB, with the exception of the draft decision not to include $170 million of assets from its opening RAB from an earlier regulatory control period.[209]

Integral Energy provided an updated value of actual capex for 2007–08.

5.4 Submissions

5.4.1 Integral Energy

Integral Energy reiterated its objection to the omission of $170 million of assets from its opening RAB. Integral Energy requested that the AER revisit its application of clause

[204] AER, *Draft decision*, p. 82.
[205] AER, *Draft decision*, p. 83.
[206] Country Energy, *Revised regulatory proposal*, p. 54.
[207] EnergyAustralia, *Revised regulatory proposal*, p. 16.
[208] EnergyAustralia, *Revised regulatory proposal*, p. 16.
[209] Integral Energy, *Revised regulatory proposal*, pp. 15–16.

S6.2.1(c) of the chapter 6 transitional rules in rolling forward the RAB to 1 July 2009, and asserted that clauses S6.2.1(c)(2) and (3) provide for the AER to increase the value of its opening RAB as at 1 July 2004 to include the assets in question. Integral Energy suggested that clauses S6.2.1(c)(2) and (3) provide for an adjustment to the RAB to rectify the previous approach to asset valuation adopted by IPART in its 2004 regulatory determination.[210]

5.5 Issues and AER considerations

5.5.1 Inflation indexation methods

In calculating its opening RAB in its revised regulatory proposal, EnergyAustralia used two indexation methods to calculate the annual change in CPI: the sum of four quarters method (for distribution) and the year on year method (for transmission) based on June–June CPI data. EnergyAustralia stated that the methods it used are consistent with the NER.[211]

In the draft decision the AER did not use CPI inputs proposed by EnergyAustralia to adjust the RAB for actual inflation in the roll forward model (RFM). The AER used the sum of four quarters to December CPI method for the distribution RAB, and the March–March quarter change CPI method for the transmission RAB. The AER considered that EnergyAustralia's proposed method for calculating CPI inputs to the RFM for adjusting the distribution RAB was not consistent with the method approved by IPART in its 2004 distribution determination.[212] The AER adopted IPART's approved method to calculate actual inflation used for indexation of the control mechanism during the current regulatory control period as required under clause 6.5.1(e)(3).[213] Similarly, the AER considered that EnergyAustralia's proposed method for calculating CPI inputs to the RFM for adjusting the transmission RAB was not consistent with the method used for indexation of the maximum allowed revenue (MAR) during the current regulatory control period.[214]

EnergyAustralia responded by stating that the transitional rules require the two RABs (for distribution and transmission) be rolled forward using different indexation methods.[215] For distribution, EnergyAustralia stated that clause 6.5.1(e)(3) requires opening RAB values to be adjusted for actual inflation, consistent with the method used for the indexation of the control mechanism for standard control services during the current regulatory control period. For transmission, EnergyAustralia stated that clause 6A.6.1(e)(3) requires the opening transmission RAB be adjusted for actual inflation consistent with the method used for the indexation of the transmission MAR.[216]

The AER agrees that the two RABs must be rolled forward using different indexation methods. The indexation methods used for the distribution and transmission RABs must be consistent with the methods used for the indexation of the price cap for distribution, and for the indexation of the MAR for transmission.

210 Integral Energy, *Submission to the AER*, pp. 4–5.
211 EnergyAustralia, *Revised regulatory proposal*, pp. 17–18.
212 IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09 – Final Report*, June 2004, p. 18.
213 AER, *Draft decision*, pp. 64–65.
214 AER, *Draft decision*, p. 74.
215 EnergyAustralia, *Revised regulatory proposal*, p. 18.
216 EnergyAustralia, *Revised regulatory proposal*, pp. 17–18.

In the current regulatory control period, the actual inflation based on the sum of four quarters to December CPI method was used for indexation of the price cap for distribution, and the actual inflation based on the March–March quarter change (or year on year) CPI method was used for indexation of the MAR for transmission. The AER maintains its position that, in accordance with clause 6.5.1(e)(3) of the transitional chapter 6 rules and clause 6A.6.1(e)(3) of the NER, these are the methods that must be used to roll forward the distribution and transmission RABs for actual inflation. The AER will amend the CPI inputs for EnergyAustralia's indexation of the RABs by using the sum of four quarters to December CPI method for distribution,[217] and the March–March quarter change method for transmission.[218]

5.5.2 RAB roll forward for 2014–19

EnergyAustralia's revised regulatory proposal referred to arguments contained in its regulatory proposal relating to unexpected and uncontrollable changes in costs that may occur during the next regulatory control period. EnergyAustralia submitted that the AER should consider the significant investment program it will undertake over the period. It also submitted that the AER should use regulated rather than actual depreciation to derive the opening RAB for the 2014–19 regulatory control period.[219]

In the draft decision the AER determined that the use of actual depreciation for establishing the opening RAB for the 2014–19 regulatory control period is appropriate.[220] This arrangement provides EnergyAustralia with a stronger incentive to better manage the costs of its capex program. The AER does not accept that this incentive should be weakened in the context of a significant capital works. EnergyAustralia did not provide any additional information beyond that included in its regulatory proposal. The AER maintains its conclusion from the draft decision, and will use actual depreciation to establish the opening RAB for the 2014–19 regulatory control period.

5.5.3 Integral Energy sub–transmission and zone substation assets

In the draft decision the AER decided that the threshold requirements in clause S6.2.1(e)(8) were not met and consequently $170 million was excluded from Integral Energy's opening RAB.[221]

In its revised regulatory proposal Integral Energy re–introduced $170 million of assets to its opening RAB that the AER had excluded in the draft decision. Integral Energy referred to a valuation by Sinclair Knight Merz Pty Ltd in 2003 which indicated that the 1998 RAB valuation was inaccurate due to an error in the asset lives of sub–transmission and zone substations. It stated the error was said to result in an underestimation of assets in the amount of $167 million. When rolled forward this equated to $170 million. This issue was considered by IPART in its 2004 determination. IPART decided not to adjust the RAB to include the assets in question.

[217] This method is consistent with that applied for Country Energy's and Integral Energy's asset roll forward during the current regulatory control period.
[218] This method is consistent with that applied for TransGrid's asset roll forward during the current regulatory control period.
[219] EnergyAustralia, *Revised regulatory proposal*, pp. 124–125.
[220] AER, *Draft decision*, p. 79.
[221] AER, *Draft decision*, p. 77.

Integral Energy stated that an adjustment to the valuation of its RAB at 2004 is required under clauses S6.2.1(c)(2) and (3) of the transitional chapter 6 rules. This was reiterated in its subsequent submission to the AER.[222]

Clause S6.2.1(c) provides:

(c) Distribution systems of specific providers

(1) In the case of a distribution system owned, controlled or operated by one of the following Distribution Network Service Providers as at the commencement of this schedule, the value of the regulatory asset base for that distribution system as at the beginning of that first regulatory year must be determined by rolling forward the regulatory asset base for that distribution system, as set out in the table below, in accordance with this schedule:

Jurisdiction	Distribution Network Service Provider	Regulatory Asset Base ($m)
Australian Capital Territory	ActewAGL	510.54 (as at 1 July 2004 in July 2004 dollars)
New South Wales	Country Energy	2,440 (as at 1 July 2004 in July 2004 dollars)
	EnergyAustralia	4,116 (as at 1 July 2004 in July 2004 dollars); plus 635.6 (as at 1 July 2004 in July 2004 dollars) in respect of EnergyAustralia's transmission support network
	Integral Energy	2,283 (as at 1 July 2004 in July 2004 dollars)
*****	*****	*****

(2) The values in the table above are to be adjusted for the difference between:

(i) any estimated capital expenditure that is included in those values for any part of a previous regulatory control period; and

(ii) the actual capital expenditure for that part of the previous regulatory control period.

This adjustment must also remove any benefit or penalty associated with any difference between the estimated and actual capital expenditure.

(3) When rolling forward a regulatory asset base under subparagraph (1), the AER must take into account the derivation of the values in the above table from past regulatory decisions and the consequent fact that they relate only to the regulatory asset base identified in those decisions.

Application of clause S6.2.1(c)(2)

The AER considers that the purpose of clause S6.2.1(c)(2) is to adjust for the difference between estimated and actual capex amounts in the 1999–04 regulatory control period.

[222] Integral Energy, *Submission to the AER*, pp. 4–5.

This clause is necessary because at the time the opening RAB as at 1 July 2004 was established, actual capex for the final year of the 1999–04 regulatory control period was not known. This clause allows the AER to update the value specified in paragraph (a) to account for actual capex in the final year of the 1999–04 regulatory control period.

Clause S6.2.1(c)(2)(i) refers to estimated capex 'that is included in those values'. 'Those values' refers to the values in paragraph (a), which for Integral Energy, is $2283 million (as at 1 July 2004 in July 2004 dollars).[223] This value of $2283 million for Integral Energy's opening RAB specified in the transitional chapter 6 rules was established by reference back to the value of the RAB determined by the previous jurisdictional regulator, IPART, for the 2004–09 regulatory control period.[224] The only estimate of capex included in the amount specified for Integral Energy in paragraph (a) is that for the final year of the 1999–04 regulatory control period. All other capex amounts, including from previous regulatory control periods, are actual amounts rather than estimates. Therefore the only adjustment for the difference between actual and estimated capex that can be made under clause S6.2.1(c)(2) is for capex in the final year of the 1999–04 regulatory control period.

The AER notes that even if an adjustment was permitted for differences between actual and estimated capex in a period before the previous regulatory control period, it is not clear from the information provided that the revaluation of assets would result in a change to capex amounts.

The AER considers that clause S6.2.1(c)(2) does not permit the inclusion of assets or capex amounts that were not included in the RAB prior to 1 July 2004.

Application of clause S6.2.1(c)(3)

Integral Energy considered that clause S6.2.1(c)(3) requires the AER to recognise how the values in paragraph (a) of the clause were derived, and to take into account the methodology used by IPART to derive the values, rather than the values themselves.[225] It suggested that the AER is not bound by the methodology adopted by IPART in determining the value of the RAB, and that the AER should include the assets notwithstanding the fact that IPART decided not to include them in the RAB.[226]

Integral Energy referred to the revenue and pricing principles in section 7A of the NEL in support of its position, suggesting that not including the assets in the RAB denies Integral Energy a reasonable opportunity to recover at least the efficient costs it incurs in providing direct control network services, as set out in subparagraph 7A(2)(a) of the NEL.[227]

The AER does not agree that not including the assets in Integral Energy's RAB denies it a reasonable opportunity to recover the efficient costs of providing direct control network services. The RAB is defined in clause 6.5.1(a) of the chapter 6 transitional rules as the value of the assets used to provide standard control services. Therefore the RAB values specified in paragraph (c)(1) of clause S6.2.1 of the transitional chapter 6 rules are taken

[223] As shown in table 5.4 and table 5.8 of this final decision.
[224] MCE, Standing Committee of Officials, *Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution*, April 2007, p. 37.
[225] Integral Energy, *Submission to the AER*, attachment 1.
[226] Integral Energy, *Submission to the AER*, attachment 1, p. 4.
[227] Integral Energy, *Submission to the AER*, attachment 1, p. 4.

to be the values of the assets used to provide standard control services, subject to the adjustments allowed under clause S6.2.1. Given that the value specified in paragraph (c)(1) of clause S6.2.1 is taken to be the value of assets used to provide standard control services, the roll forward of the RAB in accordance with the adjustments permitted under clause S6.2.1 will provide for the opportunity to recover the efficient costs of standard control services.

Integral Energy also referred to subsection (4) of the revenue and pricing principles in section 7A of the NEL in support of its position.[228] This subsection provides:

> (4) Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted-
>
> (a) in any previous-
>
> (i) as the case requires, distribution determination or transmission determination; or
>
> (ii) determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or
>
> (b) in the Rules.

The AER does not consider that this supports Integral Energy's argument that the AER must take into account the methodology used by IPART to derive the values, rather than the values themselves. Subsection 4 requires the AER to have regard to the value adopted by IPART and to the value of the opening RAB specified in paragraph (c) of clause S6.2.1. These two values are the same. The AER does not consider this subsection requires it to take account of the methodology used by IPART when having regard to the value of the RAB.

Therefore, the AER does not consider that the revenue and pricing principles in the NEL support Integral Energy's interpretation of clause S6.2.1(c)(3).

Paragraph (c)(1) of clause S6.2.1 provides that the value of the RAB as at the beginning of the first regulatory year must be determined by rolling forward the RAB, as set out in the table, in accordance with the schedule. Therefore, the AER must take the value set out in the table as the starting point. Adjustments may only be made to that value if the schedule permits. In the absence of a provision in the schedule that clearly permits the AER to make an adjustment, the value in the table will not be adjusted.

The requirement in clause S6.2.1(c)(3) to take into account the derivation of the values in the table from past regulatory decisions and the consequent fact that they relate only to the RAB identified in those decisions does not expressly provide for the AER to adjust the value determined by IPART to take account of assets that IPART did not include. An analysis of the context within which clause S6.2.1(c)(3) operates suggests that this is not the intention of clause S6.2.1(c)(3).

228 Integral Energy, *Submission to the AER*, attachment 1, p. 4.

The adjustments permitted under clause S6.2.1 take into account certain events and changes that may occur subsequent to the time that the values specified in paragraph (c) were determined by the jurisdictional regulator. For example, S6.2.1(e)(7) and (8) respectively provide for adjustments where services are reclassified such that assets that previously provided standard control services no longer provide standard control services, or where assets did not previously but now provide standard control services. There is no provision in clause S6.2.1 that allows for adjustments to the RAB values to take account of a change in circumstances that occurred before IPART established the RAB values specified in paragraph (c).

The Ministerial Council on Energy (MCE) Standing Committee of Officials stated in its explanatory material accompanying the first exposure draft of amendments to chapter 6:[229]

> Acknowledging that the jurisdictional regulators' past determination would not bind future determinations, the AER will need to make any other adjustments to the RAB at the next determination that the jurisdictional regulators had envisaged in their determinations, policies or guidelines. However, this does not provide an opportunity to reopen the regulatory asset base.

This suggests that the Ministerial Council on Energy did not intend that the RAB values specified in clause S6.2.1(c)(1) could be reopened to account for a revaluation of assets that IPART did not envisage.

In light of the above, the AER considers that clause S6.2.1(c)(3) does not permit the AER to take account of a change in asset lives that was identified and brought to the attention of IPART prior to the determination of the opening RAB by IPART in the 2004–09 regulatory determination.

The AER considers that clause S6.2.1(c)(3) does not permit the AER to make the amendment proposed by Integral Energy to vary the value of the opening RAB as at 1 July 2004. Therefore, the AER decides not to adjust Integral Energy's opening RAB to include the $170 million proposed by Integral Energy.

5.5.4 Updated data

In the draft decision the AER stated that it would update the roll forward of the NSW DNSPs' RABs with actual capex for 2007–08. The NSW DNSPs provided their actual capex values for 2007–08 and the AER has accepted these as inputs to the RFM. In respect of the capex forecast for 2008–09, the AER notes that to the extent that actual capex differs from this forecast capex, a reconciliation will be undertaken using the actual values as part of the asset base roll forward process at the next distribution determination, in accordance with the NER.

The roll forward of the NSW DNSPs' RABs has been updated to include the latest CPI data, which was published by the Australian Bureau of Statistics (ABS) in January 2009, consistent with the methods approved in the draft decision.

On 17 April 2009, Integral Energy advised the AER that the CPI inputs for 2002–03 and 2003–04 in the RFMs require amendments so that they reflect the indexation method

[229] MCE, Standing Committee of Officials, *Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution*, April 2007, p. 44.

approved by IPART in its 1999 regulatory determination. The AER notes that in the IPART determination the indexation of the price cap was based on a December–December quarter change method.[230] The CPI inputs for 2002–03 and 2003–04 were calculated in the AER's draft decision based on the sum of four quarters to December CPI method (as noted in section 5.5.1, this is the indexation method approved for the current regulatory control period in the IPART 2004 distribution determination). The AER has therefore amended the 2002–03 and 2003–04 CPI inputs in the NSW DNSPs' RFMs for this final decision, using the indexation method consistent with the IPART 1999 distribution determination.

5.6 AER conclusion

5.6.1 Country Energy

To take into account the updated capex and CPI data, the AER amends its draft decision and determines Country Energy's opening RAB for the next regulatory control period to be $4319 million (as at 1 July 2009). The RAB roll forward calculations are set out in table 5.5.

Table 5.5: AER conclusion on Country Energy's opening RAB for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	2439.0	2639.0	2921.1	3325.5	3742.4
Actual net capex (adjusted for actual CPI and WACC)[c]	276.7	366.7	473.2	537.9	649.0
CPI adjustment on opening RAB	57.2	70.4	103.4	77.6	162.9
Straight–line depreciation (adjusted for actual CPI)	–133.9	–155.0	–172.2	–198.6	–226.1
Closing RAB	2639.0	2921.1	3325.5	3742.4	4328.2
Adjustment for difference between actual and forecast capex for 2003–04					–5.4
Adjustment for return on difference[d]					–3.4
Opening RAB at 1 July 2009					4319.4

(a) Updated for actual 2007–08 capex.
(b) Updated for actual CPI for 2008–09 (sum of four quarters to December).
(c) The capex values include a half WACC allowance to compensate for the average six–month period before capex is added to the RAB for revenue modelling purposes. The cash values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $5.4 million for 1 July 2003 to 30 June 2004.

230 IPART, *Regulation of New South Wales Electricity Distribution Networks – Determination and Rules under the National Electricity Code*, December 1999, p. 16.

5.6.2 EnergyAustralia

To take into account the updated capex and amended CPI data, the AER amends its draft decision and determines EnergyAustralia's opening RAB (comprising distribution and transmission) for the next regulatory control period to be $8326 million (as at 1 July 2009). The RAB roll forward calculations are set out in tables 5.6 and 5.7, and provide for a distribution opening RAB of $7297 million (as at 1 July 2009) and a transmission opening RAB of $1028 million (as at 1 July 2009).

Table 5.6: AER conclusion on EnergyAustralia's opening RAB (distribution) for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	4064.0	4428.9	4916.0	5627.0	6357.6
Actual net capex (adjusted for actual CPI and WACC)[c]	432.7	549.9	740.5	833.0	934.3
CPI adjustment on opening RAB	95.2	118.2	174.0	131.2	276.7
Straight–line depreciation (adjusted for actual CPI)	–163.1	–181.0	–203.4	–233.7	–269.1
Closing RAB	4428.9	4916.0	5627.0	6357.6	7299.5
Adjustment for difference between actual and forecast capex for 2003–04					27.1
Adjustment for return on difference[d]					17.1
Adjustment for system assets moving from distribution to transmission					–57.8
Adjustment for non–system asset re-allocation					11.2
Opening RAB at 1 July 2009					7297.2

(a) Updated for actual 2007–08 capex.
(b) Updated for actual CPI for 2008–09 (sum of four quarters to December).
(c) The capex values include a half WACC allowance to compensate for the average six–month period before capex is added to the RAB for revenue modelling purposes. The cash values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $27.1 million for 1 July 2003 to 30 June 2004.

Table 5.7: AER conclusion on EnergyAustralia's opening RAB (transmission) for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	635.6	663.0	698.9	725.7	830.4
Actual net capex (adjusted for actual CPI and WACC)[c]	39.0	44.7	40.8	107.0	167.5
CPI adjustment on opening RAB	15.0	19.8	17.0	30.8	20.5
Straight–line depreciation (adjusted for actual CPI)	–26.7	–28.6	–31.0	–33.1	–36.5
Closing RAB	663.0	698.9	725.7	830.4	981.9
Adjustment for system assets moving to transmission from distribution					57.8
Adjustment for non–system asset re-allocation					–11.2
Opening RAB at 1 July 2009					1028.5

(a) Updated for actual 2007–08 capex.
(b) Updated for actual CPI for 2008–09 (March to March).
(c) The capex values include a half WACC allowance to compensate for the average six–month period before capex is added to the RAB for revenue modelling purposes. The accounting book values for disposal of assets have been deducted.

5.6.3 Integral Energy

To take into account the updated capex and CPI data, the AER amends its draft decision and determines Integral Energy's opening RAB for the next regulatory control period to be $3690 million (as at 1 July 2009). The RAB roll forward calculations are set out in table 5.8.

For the reasons discussed above, Integral Energy's opening RAB has not been adjusted to include $170 million of assets which Integral Energy claimed were undervalued in the 1999–04 regulatory control period.

Table 5.8: AER conclusion on Integral Energy's opening RAB for the next regulatory control period ($m, nominal)

	2004–05	2005–06	2006–07	2007–08[a]	2008–09[b]
Opening RAB	2283.5	2454.7	2707.6	3021.3	3280.6
Actual net capex (adjusted for actual CPI and WACC)[c]	248.5	330.0	376.1	365.6	555.3
CPI adjustment on opening RAB	53.5	65.5	95.8	70.5	142.8
Straight–line depreciation (adjusted for actual CPI)	–130.8	–142.6	–158.1	–176.8	–193.6
Closing RAB	2454.7	2707.6	3021.3	3280.6	3785.0
Adjustment fordifference between actual and forecast capex for 2003–04					–58.3
Adjustment for return on difference[d]					–36.7
Opening RAB at 1 July 2009					3690.0

(a) Updated for actual 2007–08 capex.
(b) Updated for actual CPI for 2008–09 (sum of four quarters to December).
(c) The capex values include a half WACC allowance to compensate for the average sixmonth period before capex is added to the RAB for revenue modelling purposes. The accounting book values for disposal of assets have been deducted.
(d) This relates to the difference between actual and forecast capex of $58.3 million for 1 July 2003 to 30 June 2004.

5.7 AER decision

In accordance with clause 6.12.1(6) of the transitional chapter 6 rules the opening regulatory asset base at 1 July 2009 for Country Energy is as set out in table 5.5 of this final decision.

In accordance with clause 6.12.1(6) of the transitional chapter 6 rules the opening regulatory asset base at 1 July 2009 for EnergyAustralia (distribution) is as set out in table 5.6 of this final decision.

In accordance with clause 6.12.1(6) of the transitional chapter 6 rules opening regulatory asset base at 1 July 2009 for EnergyAustralia (transmission) is as set out in table 5.7 of this final decision.

In accordance with clause 6.12.1(6) of the transitional chapter 6 rules opening regulatory asset base at 1 July 2009 for Integral Energy is as set out in table 5.8 of this final decision.

In accordance with clause 6.12.1(18) of the transitional chapter 6 rules the AER will use actual depreciation to establish the regulatory asset base for the NSW DNSPs at the commencement of the 2014–19 regulatory control period.

6 Demand forecasts

6.1 Introduction

This chapter sets out the AER's consideration of the NSW DNSPs' maximum demand, energy consumption (energy) and customer number forecasts. As part of making its final determination, the AER must assess the extent to which the NSW DNSPs' maximum demand forecasts can be relied upon for the purposes of estimating load driven capex. The AER must also make a decision on whether the NSW DNSPs' energy and customer number forecasts are appropriate inputs into the post–tax revenue model (PTRM), which is used in determining X factors.

6.2 AER draft decision

6.2.1 Maximum demand

The draft decision stated that Country Energy's and EnergyAustralia's maximum demand forecast methodologies and forecasts provided a realistic expectation of the demand forecast required to achieve the capex and opex objectives in the transitional chapter 6 rules. The draft decision stated that Integral Energy's revised maximum demand forecast, submitted on 29 August 2008, provided a realistic expectation of forecast demand, as required to achieve the capex and opex objectives in the transitional chapter 6 rules.[231]

6.2.2 Customer numbers

The draft decision stated that EnergyAustralia's and Integral Energy's revised customer number forecasts (provided to the AER on 29 and 31 October 2008, respectively) were reasonable inputs to use in the PTRM in determining X factors.[232] The draft decision considered that Country Energy's June 2008 customer number forecasts were outdated. The AER requested Country Energy to provide revised customer number forecasts.[233]

6.2.3 Energy

The draft decision stated EnergyAustralia's and Integral Energy's revised energy forecast methodologies (provided to the AER on 29 and 31 October 2008, respectively), and Country Energy's June 2008 energy forecasts were reasonable. However, the NSW DNSPs' energy forecasts were rejected on the basis that they needed to be updated to take into account the most recent energy sales data for regulatory year 2007–08, for consideration in the final decision.[234]

6.3 Revised regulatory proposals

6.3.1 Country Energy

6.3.1.1 Maximum demand

The draft decision accepted Country Energy's maximum demand forecast.

231 AER, *Draft decision*, pp. 115–116.
232 AER, *Draft decision*, pp. 116–117.
233 AER, *Draft decision*, pp. 115–116.
234 AER, *Draft decision*, pp. 115–117.

However, Country Energy provided revised summer and winter global maximum demand forecasts, generated by the National Institute of Economic and Industry Research (NIEIR).[235] In the revised global forecasts, Country Energy's original forecasts were updated to account for the latest economic forecasts resulting from the global financial crisis, and NIEIR's reassessment of the impact of the proposed Carbon Pollution Reduction Scheme (CPRS) following the release of the Australian Government's December 2008 White Paper.[236]

The revised global forecasts were calculated using the same methodology[237] used to generate Country Energy's June 2008 forecasts, which were assessed by the AER in the draft decision. While the June 2008 maximum demand forecasts were prepared at the local government area level as well as at the top–down global level, the January 2009 revised forecasts were prepared only at a global level.[238] Due to the limited time between the release of the draft decision and the date by which Country Energy was required to submit its revised regulatory proposal, it was not feasible for Country Energy to collate revised spatial maximum demand forecasts for each local government area. Instead, Country Energy prepared a global, top–down assessment of the impact of the worsening global financial crisis and CPRS on maximum demand.[239]

Country Energy's original and revised maximum demand forecasts are presented in table 6.1.

Table 6.1: Country Energy's maximum demand forecasts (50% probablility of exceedence - MW)

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth rate 2009–14[a]
Original summer forecast	2404	2484	2583	2653	2728	3.0%
Revised summer forecast	2325	2386	2515	2602	2681	3.0%
Original winter forecast	2405	2461	2515	2551	2589	1.8%
Revised winter forecast	2931	2406	2446	2475	2511	1.7%

Source: Country Energy, *Regulatory proposal,* Regulatory proformas, confidential, table 2.3.8 and Country Energy, *Revised regulatory proposal*, p. 16.

(a) Average annual growth rate includes growth from year 2008–09.

235 Country Energy, *Revised regulatory proposal*, appendix A.

236 Australian Government, *Carbon Pollution Reduction Scheme—Australia's Low Pollution Future—White Paper*, December 2008.

237 Country Energy, *Revised regulatory proposal*, p. 16.

238 While the other NSW DNSPs forecast spatial maximum demand at the zone substation level, Country Energy's network is classified according to local government areas and previous NSW County Council regions. This is a legacy associated with the formation of the Country Energy network.

239 AER, phone call to Country Energy, 4 March 2009.

6.3.1.2 Customer numbers

The draft decision required Country Energy to provide a revised forecast of customer numbers using the most recent data as a starting point.[240]

Country Energy provided a revised customer number forecast, using actual customer numbers as at June 2008 as a starting point and grown at NIEIR's updated average annual growth rate for the next regulatory control period.[241] This revised forecast was also updated to take into account the impact of the global economic downturn resulting from the global financial crisis. As a result, Country Energy has forecast new customer connections to grow by an average of 1.3 per cent per annum over the next regulatory control period, compared to its June 2008 forecast of 1.5 per cent per annum.[242]

Country Energy's customer number forecasts are presented in table 6.2.

Table 6.2: Country Energy's customer number forecasts 2009–14

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14[a]
Original forecast (June 2008)[b]	1 334 534	1 354 010	1 373 771	1 393 820	1 414 163	1.5%
Revised forecast (February 2009)	1 321 286	1 339 074	1 357 118	1 375 421	1 393 989	1.3%

Source: Country Energy, *Regulatory proposal,* Regulatory proformas, confidential, table 2.3.8; and Country Energy, email to the AER, 24 February 2009.

(a) Average annual growth includes growth from year 2008–09.

(b) The AER notes that Country Energy's June 2008 customer number forecast reported in the draft decision was an aggregate customer number representation consistent with NIEIR's reports. For application in the PTRM a different forecast format is appropriate, however growth rates are consistent across both NIEIR's customer number forecast and the inputs into the PTRM.

6.3.1.3 Energy

The draft decision required Country Energy to provide a revised energy forecast, using audited 2007–08 weighted average price cap (WAPC) energy sales data as a starting point, and escalated according to the methodology that was reviewed by the AER.[243]

Country Energy provided a revised energy forecast based on audited energy sales data for 2007–08. This revised forecast incorporated 2007–08 WAPC data, grown according to NIEIR's updated forecast of average annual energy growth for Country Energy's

[240] AER, *Draft decision*, p. 115.

[241] Country Energy's final revised customer number forecast was provided to the AER via email on 24 February 2009, once final 2007–08 WAPC data became available. This final forecast updated the forecast submitted as part of Country Energy's revised regulatory proposal in NIEIR's report (Appendix A, table 6.1), applying NIEIR's updated average annual growth rate for the next regulatory control period to the new base data. Country Energy, email to the AER, 24 February 2009.

[242] Country Energy, *Revised regulatory proposal*, p. 15.

[243] AER, *Draft decision*, p. 115.

region.[244] The revised forecast took into account NIEIR's reassessment of the impact of the CPRS and its updated economic outlook.[245] Country Energy's revised energy forecast is presented in table 6.3.

Table 6.3: Country Energy's energy forecasts 2009–14 (GWh)

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14[a]
Original forecast (June 2008)	12 507	12 769	13 020	13 152	13 292	1.6%
Revised forecast (February 2009)	12 092	12 147	12 202	12 258	12 314	0.5%

Source: Country Energy, *Regulatory proposal,* Regulatory proformas, confidential, table 2.3.8 and Country Energy, *email to the AER,* 24 February 2009.
(a) Average annual growth includes growth from year 2008–09.

6.3.2 EnergyAustralia

6.3.2.1 Maximum demand

The draft decision accepted EnergyAustralia's maximum demand forecast provided in June 2008 as reasonable, following a review by the AER's consultant, McLennan Magasanik Associates (MMA) which found the forecast methodology to be reasonable.[246]

However, in its revised regulatory proposal EnergyAustralia stated that it considered it was necessary to update its maximum demand forecast to take into account the impact of the worsening global financial crisis, the timing and magnitude of price increases resulting from the CPRS, a number of newly introduced NSW Government levies and the draft decision.[247]

EnergyAustralia's revised regulatory proposal stated that in revising its maximum demand forecasts it has maintained the same methodology used to generate its June 2008 forecast, which was considered to be a reasonable methodology by MMA and the AER.[248] EnergyAustralia advised that it was unable to perform a full revised spatial maximum demand forecast, and only carried out a top–down adjustment of its maximum demand forecast to account for the changes in economic growth and electricity prices.[249] EnergyAustralia's maximum demand forecasts are presented in table 6.4.

244 Country Energy's final revised energy forecast was provided to the AER via email on 24 February 2009, once final 2007–08 WAPC data became available. This final forecast updated the forecast submitted as part of Country Energy's revised regulatory proposal in NIEIR's report (Appendix A, table 6.1), applying NIEIR's updated average annual growth rate for the next regulatory control period to the new base data. Country Energy, email to the AER, 24 February 2009.
245 Country Energy, *Revised regulatory proposal*, pp. 14–15.
246 AER, *Draft decision*, p. 103.
247 EnergyAustralia, *Revised regulatory proposal*, pp. 23–24.
248 EnergyAustralia, *Revised regulatory proposal*, p. 23.
249 EnergyAustralia, *Revised regulatory proposal*, attachment 3A, p. 8.

Table 6.4: EnergyAustralia's maximum demand forecasts (50% POE - MW)[a]

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14[b]
Original forecast (June 2008)	6205	6378	6550	6722	6894	2.8%
Revised forecast (January 2009)	6022	6046	6254	6467	6679	2.7%

Source: EnergyAustralia, *Regulatory proposal,* Regulatory proformas, confidential, table 2.3.8 and EnergyAustralia, *Revised regulatory proposal* - Attachment 13A, table 1.2.
(a) All values are for summer peak demand.
(b) Average annual growth includes growth from year 2008–09.

EnergyAustralia's revised regulatory proposal detailed some reductions in its planned capex program as a result of this revised top–down maximum demand forecast.[250] The AER's consideration of these changes is presented in chapter 7.

6.3.2.2 Customer numbers

The draft decision accepted the customer number forecast provided by EnergyAustralia on 29 October 2008 as an appropriate input into its PTRM.[251] This forecast was prepared following recommendations made by MMA and the AER.

EnergyAustralia's revised regulatory proposal stated that it had reviewed recent forecasts of dwelling approvals from a number of sources, and found that there was considerable uncertainty over the timing and magnitude of the forecast economic recovery in NSW. However, EnergyAustralia stated that it did not consider there was a need to further update its forecast of customer numbers from that provided to the AER on 29 October 2008.[252]

6.3.2.3 Energy

In the draft decision, the AER stated that it considered the energy forecast provided to it on 29 October 2008 was generated according to sound methodology. However, the AER requested that the forecast be updated for the latest audited WAPC energy sales data for 2007–08.[253]

In its revised regulatory proposal, EnergyAustralia stated that the draft decision gave inappropriate directions on how its energy forecast should be revised, which if implemented would result in an unreasonable volume forecast.[254] However, EnergyAustralia also stated that it considered it necessary to 'thoroughly revise its forecasts using the process which the AER has endorsed as reasonable'.[255] EnergyAustralia provided a revised energy forecast using updated data and inputs and

[250] EnergyAustralia, *Revised regulatory proposal*, pp. 24–26.
[251] AER, *Draft decision*, p. 116.
[252] EnergyAustralia, *Revised regulatory proposal*, pp. 23–34 and p. 121.
[253] AER, *Draft decision*, p. 116.
[254] EnergyAustralia, *Revised regulatory proposal*, p. 116.
[255] EnergyAustralia, *Revised regulatory proposal*, pp. 116–117.

incorporating some changes recommended by the AER's consultant, MMA, in its report on EnergyAustralia's energy forecast methodology.[256] The revised forecast took into account the impact of the worsening global financial crisis, as well as the impact on demand of anticipated electricity price rises resulting from:[257]

- the introduction of the CPRS
- outcomes of the draft determinations for EnergyAustralia and TransGrid
- outcomes of the IPART's retail price determination (made in July 2007)
- increases in DNSP levies and coal royalties stipulated in the NSW Government's November 2008 mini–budget.

EnergyAustralia's energy forecasts are presented in table 6.5.

Table 6.5: EnergyAustralia's energy forecasts 2009–14 (GWh)[a]

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14[b]
Original forecast (June 2008)	28 466	28 986	29 455	29 736	30 136	1.6%
Revised forecast (October 2008)	28 350	28 766	29 128	29 298	29 582	1.2%
Revised forecast (January 2009)	26 663	25 132	25 172	25 017	24 968	–2%

Source: EnergyAustralia, October forecast model (provided to the AER on 27 February 2009) and EnergyAustralia, *Revised regulatory proposal,* Attachment 13A, table 1.1.
(a) The AER notes that the figures in table 6.7 of its draft decision included some large customer loads that are typically excluded from energy forecasts. The figures in the table above do not include these loads.
(b) Average annual growth includes growth from year 2008–09.

EnergyAustralia's January 2009 revised energy forecast indicated that it now anticipates energy consumption in 2013–14 will be only 88 per cent of its original June 2008 forecast for 2009–10.[258]

6.3.3 Integral Energy

6.3.3.1 Maximum demand

Integral Energy did not provide a revised maximum demand forecast in its revised regulatory proposal.[259] However, Integral Energy did acknowledge that the worsening

256 MMA, *Regulatory Proposal 2009–14—Review of EnergyAustralia's customer number and energy forecasts*, 26 September 2008, confidential.
257 EnergyAustralia, *Revised regulatory proposal*, pp. 116–117.
258 Derived from: EnergyAustralia, October forecast model, 27 February 2009; and EnergyAustralia, *Revised regulatory proposal*, attachment 13A, table 1.1.
259 The AER understands that there was insufficient time between the draft decision and Integral Energy's revised regulatory proposal for Integral Energy to prepare a revised spatial maximum demand forecast.

global financial crisis was likely to reduce its required growth capex for the next regulatory control period. Accordingly, it provided a revised capex proposal incorporating a global assessment of the impact of the worsening economic downturn.[260] The AER's consideration of Integral Energy's revised capex proposal is provided in chapter 7.

6.3.3.2 Customer numbers

The draft decision accepted the customer number forecast provided by Integral Energy on 31 October 2008 as an appropriate input into its PTRM.[261] This forecast was developed following changes recommended by the AER's consultant, MMA, which resulted in a higher forecast than that submitted in Integral Energy's original regulatory proposal.

However, Integral Energy's revised regulatory proposal included a revised customer number forecast, based on audited 2007–08 WAPC data and incorporating the effects of a revised NIEIR gross state product (GSP) forecast for Integral Energy's region. NIEIR's GSP forecast was updated in December 2008 to incorporate the worsening global financial crisis and the impact of the CPRS White Paper.[262]

Integral Energy's customer number forecasts are provided in table 6.6.

Table 6.6: Integral Energy's customer number forecasts 2009–14[a]

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2010–14[b]
Original forecast (June 2008)	857 362	867 118	877 711	888 071	899 438	1.2%
Revised forecast (October 2008)	869 497	881 923	895 362	908 553	922 777	1.5%
Revised forecast (January 2009)	860 392	866 018	873 565	885 078	896 496	1%

Source: Integral Energy, *Regulatory proposal*, proforma 2.3.8, tables 1 and 3; Integral Energy, *Forecasts for Energy and Customer numbers*, 31 October 2008 and Integral Energy, *Revised regulatory proposal,* table 4.3.

(a) The AER notes that the figures in table 6.6 exclude controlled loads.

(b) Due to data limitations, average annual growth does not include growth from year 2008–09.

6.3.3.3 Energy

The draft decision stated that, while the AER considered the energy forecast provided to it by Integral Energy on 29 October 2008 was generated according to sound methodology, the AER considered that the forecast should be updated for the latest audited WAPC energy sales data for 2007–08.[263]

The AER notes that this was the case for the other NSW DNSPs, who stated that they were only able to carry out a top–down assessment of the impact of the changes on maximum demand.

260 Integral Energy, *Revised regulatory proposal*, appendix D.

261 AER, *Draft decision*, p. 117.

262 Integral Energy, *Revised regulatory proposal*, pp. 25–26 and appendix A.

263 AER, *Draft decision*, p. 117.

Integral Energy's revised regulatory proposal included a revised energy forecast, incorporating audited 2007–08 WAPC data and an updated NIEIR GSP forecast for Integral Energy's region. NIEIR's revised GSP forecast accounted for the expected impact on economic growth of the introduction of the CPRS, as outlined in the Australian Government's December 2008 White Paper.[264]

In developing its revised forecasts, Integral Energy substantially retained the methodology used to generate its October 2008 energy forecast, as considered by the AER in the draft decision. This approach involved adopting NIEIR's base–case GSP forecast instead of a combination of NIEIR's base and low–case forecasts as was done in Integral Energy's original energy forecast.

Integral Energy's energy forecasts are provided in table 6.7.

Table 6.7: Integral Energy's energy forecasts 2009–14 (GWh)

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14[a]
Original forecast (June 2008)	17 927	18 160	18 460	18 664	18 906	1.3%
Revised forecast (October 2008)	17 886	17 976	18 280	18 516	18 781	1.1%
Revised forecast (January 2009)	17 373	17 313	17 526	17 967	18 202	0.7%

Source: Integral Energy, *Regulatory proformas*, table 2.3.8; Integral Energy, *Forecasts for energy and customer numbers*, 31 October 2008 and Integral Energy, *Revised regulatory proposal*, Attachment 1, confidential.

(a) Average annual growth includes growth from year 2008–09.

6.4 Submissions

The AER received submissions on its draft decision relating to demand forecasts from Country Energy, EnergyAustralia, the Energy Markets Reform Forum (EMRF), the Energy Users Association of Australia (EUAA), Origin Energy and the Public Interest Advocacy Centre (PIAC).

6.4.1 Country Energy

Country Energy's submission on the draft decision stated that it would provide data relating to its audit of 2007–08 WAPC quantities to the AER by 20 February 2009, in accordance with the draft decision.[265] Country Energy also indicated that it had completed further analysis of the impact of its revised demand forecasts on its capex program for the next regulatory control period, and had identified some opportunities for deferral of

264 Integral Energy, *Revised regulatory proposal*, pp. 24–25 and appendix A. It is noted that Integral Energy's revised energy forecast did not incorporate anticipated direct customer responses to higher electricity prices expected to result from the CPRS and other government policies, in contrast to EnergyAustralia's revised energy forecast.

265 Country Energy, *Draft NSW distribution determination*, p. 1.

capex.[266] The AER's consideration of Country Energy's capex allowance is provided in chapter 7.

6.4.2 EnergyAustralia

EnergyAustralia's submission on the draft decision further outlined its revised energy forecasts that it provided as part of its revised regulatory proposal. EnergyAustralia explained its rationale for electing a combined Econtech and Australia and New Zealand Banking Group Limited (ANZ) GSP forecast, and compared its forecast to the latest Econtech forecast, released on 3 February 2009.[267]

EnergyAustralia also further outlined its revised maximum demand forecast, stating its view that expected electricity price increases over the next regulatory control period are unlikely to significantly reduce maximum demand. EnergyAustralia referred to recent electricity growth trends in South Australia to support its argument.[268]

EnergyAustralia provided some analysis of the other NSW DNSPs' treatment of electricity price movements over the next regulatory control period, and noted the variety of opinion in relation to the expected changes in gross state product (GSP) and electricity prices.[269]

EnergyAustralia also provided a submission in response to stakeholder submissions on the draft decision. This submission further described EnergyAustralia's revised maximum demand and energy forecasts, but provided no new information or arguments regarding the revised forecast methodology or forecasts.[270]

6.4.3 The Energy Markets Reform Forum

The EMRF argued that, given the recent economic downturn, energy demand in the next three to four years is unlikely to be as high as forecast by the NSW DNSPs.[271] It noted that the AER's and its consultant's reviews of the NSW DNSPs forecasts were carried out prior to the extent of the global financial crisis becoming apparent.[272] The EMRF also noted that the fall in the value of the Australian dollar since the forecasts were prepared will result in fewer customers purchasing imported air conditioners.[273]

The EMRF stated that the expected increases in costs to NSW DNSPs are no longer correct given the likely impact of the global financial crisis, and that the NSW DNSPs' capex programs need to be reassessed by the AER to determine the impact of the economic downturn.[274]

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266 Country Energy, *Draft NSW distribution determination*, pp. 2–3.

267 EnergyAustralia, *Further submission on the AER's draft determination*, February 2009, p. 11. The AER notes that in July 2008, Econtech was aquired by KPMG, and subsequently became known as KPMG Econtech. However, for clarity the AER has maintained Econtech's original title in this final decision.

268 EnergyAustralia, *Further submission*, p. 12.

269 EnergyAustralia, *Further submission*, p. 12.

270 EnergyAustralia, *Response to stakeholder submissions.*

271 EMRF, *A response, AER NSW electricity distribution revenue reset, AER draft decision*, February 2009, pp. 8–9.

272 EMRF, p. 11.

273 EMRF, pp. 11–12.

274 EMRF, pp. 10–12.

6.4.4 The Energy Users Association of Australia

The EUAA requested that the AER perform a robust analysis of the NSW DNSPs' revised forecasts to ensure that they accurately reflect the economic environment, including the latest data on declining economic activity.[275] The EUAA stated that neither the draft decision or the NSW DNSPs' revised regulatory proposals reflected the recent official forecasts for economic growth.[276] It submitted that the revised X factors are at odds with the current economic environment, and cannot be justified in an environment of worsening global economic decline.[277]

The EUAA submitted that both economic recession and greater energy efficiency will reduce growth in demand from that forecast by the NSW DNSPs.[278] It requested that the AER carry out a robust analysis of the future economic climate for NSW, so that the NSW DNSPs' capex is more reflective of the economic environment.[279]

6.4.5 Origin Energy

Origin Energy submitted that the AER should take further account of the economic downturn in relation to demand forecasts, to ensure expenditure for the next regulatory control period remains at efficient levels.[280]

Origin Energy supported the AER's decision to require updated energy forecasts based on more recent sales revenue data. However, it stated that the forecasts should also be adjusted to account for impacts of the CPRS, energy efficiency schemes, individual consumer awareness, conservation measures and NSW DNSPs' demand management initiatives.[281] Origin Energy also noted that there was significant uncertainty as to the impacts of such policies on demand forecasts, and requested that the AER's review ensure these matters are taken into account.[282]

6.4.6 The Public Interest Advocacy Centre

The PIAC noted EnergyAustralia's revised demand forecasts incorporate an expected decline in demand of up to 10 per cent over the next regulatory control period, driven by the CPRS and changes in forecast economic growth.[283] It noted a number of additional government policies that are expected to impact on energy demand in the next regulatory control period, including:[284]

- the Australian Government's program to increase the rate of installed household insulation
- the Australian Government's proposal to phase out electric storage hot water heaters

[275] EUAA, *Submission to AER's draft decision and revised DNSP proposals – review of the regulatory proposals by the NSW electricity distributors*, 16 February 2009, p. 6.
[276] EUAA, pp. 6, 9.
[277] EUAA, p. 27.
[278] EUAA, p. 23.
[279] EUAA, p. 23.
[280] Origin Energy, p. 3.
[281] Origin Energy, pp. 5–6.
[282] Origin Energy, p. 6.
[283] PIAC, *Response to the AER draft distribution determination 2009–10 to 2013–14*, p. 3.
[284] PIAC, p. 3.

- various Australian and state government rebates for solar hot water systems and photovoltaic units
- the impending NSW Government decision on the introduction of a feed-in tariff scheme.

The PIAC recommended that the AER's final determinations and associated demand forecasts be re-opened at a later date when more information is available. It noted that the result of reducing demand forecasts, without adequately reducing capex by revising forecasts for peak demand, would be increased unit prices for households without savings through deferred network augmentation.[285]

6.5 Issues and AER considerations

6.5.1 Maximum demand forecasts

AER draft decision

The draft decision stated that Country Energy's and EnergyAustralia's maximum demand forecast methodologies and forecasts provided a realistic expectation of the demand forecasts required to achieve the capex and opex objectives in the transitional chapter 6 rules. The draft decision stated that Integral Energy's revised maximum demand forecast, provided on 29 August 2008, provided a realistic expectation of forecast demand, as required to achieve the capex and opex objectives in the transitional chapter 6 rules.

Revised regulatory proposals

Country Energy and EnergyAustralia provided revised global maximum demand forecasts, accounting for the impacts of revised economic forecasts resulting from the global economic downturn and the CPRS White Paper. EnergyAustralia's revised global maximum demand forecasts also incorporated the expected impact of a number of other electricity price rises anticipated over the next regulatory control period.

Integral Energy did not provide a revised maximum demand forecast. However, its revised regulatory proposal acknowledged that the worsening global financial crisis was likely to reduce its required growth capex for the next regulatory control period. Accordingly, Integral Energy provided a revised capex proposal incorporating the worsening economic downturn.[286] The AER's consideration of Integral Energy's revised capex proposal is set out in chapter 7.

Methodologies for developing revised forecasts

Country Energy's revised global maximum demand forecasts were prepared by NIEIR, using a methodology that was described in Country Energy's original proposal, and updated to account for the most recent and up to date information available.[287] NIEIR listed the following updates made to the model:[288]

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285 PIAC, p. 3.
286 Integral Energy, *Revised regulatory proposal*, appendix D.
287 Country Energy, *Revised regulatory proposal*, p. 13.
288 NIEIR, *Electricity forecasts for the Country Energy region to 2019—Energy, customer numbers and maximum demands,* December 2008.

- an updated economic outlook, incorporating the financial sector distress which intensified over the last three months of 2008
- a preliminary reassessment of the impact of the Australian Government's CPRS following the release of the White Paper in December 2008, including customer responses to rising electricity prices[289]
- actual energy, customer numbers and peak demands for Country Energy for financial year 2007–08.

EnergyAustralia generated its revised maximum demand forecasts, which were reviewed by its consultants Oakley Greenwood Pty Ltd.[290] EnergyAustralia stated that it revised its peak demand forecasts to:[291]

- consider the revised outlook for economic growth
- account for the timing and magnitude of electricity price increases resulting from the CPRS, various NSW Government levies and the AER's draft determination.

While EnergyAustralia incorporated anticipated impacts of electricity price increases into its revised global maximum demand forecast, it assumed that this will have only a minor impact on residential peak demand, and no impact on non–residential peak demand. EnergyAustralia's response to stakeholder submissions on the draft decision stated its view that the likely elasticity of peak demand is not significant, and that in its view, customers will react to price changes by conserving their energy usage on relatively mild days, but are unlikely to change their consumption habits on extreme temperature days.[292]

AER considerations

The AER notes that while Country Energy and EnergyAustralia's revised regulatory proposals state that they have developed revised maximum demand forecasts, these forecasts were prepared on a global (top–down) basis, and do not incorporate spatial forecasts at the zone substation level.[293] While global forecasts are useful as a check on spatial forecasts and to indicate general trends on the networks, spatial forecasts are required to assess necessary expenditure on the network. As there was insufficient time for the DNSPs to prepare revised spatial maximum demand forecasts, the AER's assessment of the revised global maximum demand forecasts and the impacts on load driven capex are limited to a high–level assessment of reasonableness. This is considered further in chapter 7.

Country Energy's revised maximum demand forecasts

Subsequent to receiving Country Energy's revised regulatory proposal, the AER requested that Country Energy provide further information on why summer maximum demand on its network was forecast to remain unchanged from the June 2008 forecast,

289 Country Energy, *Revised regulatory proposal*, appendix A, p. 49. Appendix A indicates that NIEIR has assumed a price elasticity of peak demand to assess the impact of the CPRS.

290 Oakley Greenwood, *Review of Revised Forecasts for EnergyAustralia*, 13 January 2009.

291 EnergyAustralia, *Revised regulatory proposal*, p. 24.

292 EnergyAustralia, *Response to stakeholder submissions*, p. 4.

293 AER, phone call to Country Energy, 4 March 2009 and EnergyAustralia, *Response to stakeholder submissions*, p. 2.

but winter maximum demand growth was forecast to decline slightly in comparison to the June 2008 forecast.[294]

Country Energy considered that summer maximum demand is more sensitive to weather than it is to economic growth. Country Energy cited recent sales in low cost air conditioners during heat waves in NSW and Victoria as evidence that the global financial crisis is not likely to significantly reduce summer maximum demand growth. It stated that most people would see the cost of running an air conditioner on a very hot day as affordable.[295] Country Energy also stated that it considers customers' cost saving responses to the worsening global financial crisis are more likely to be expressed by people waiting longer to turn their air conditioners on, as opposed to not turning their air conditioners on at all. It stated that this change in behaviour does not reduce expected system peak demand.[296]

Country Energy stated that the winter peak on its network is not as influenced by the increased uptake of low cost air conditioners, and will be reduced by lower number of customer connections and a reduction in the purchase of lifestyle appliances, such as plasma TVs and computers.[297]

The AER notes Country Energy's statement that the global economic downturn is unlikely to result in people significantly lowering their use of air conditioners at peak times is at odds with the EMRF's statement that the falling exchange rate will result in fewer purchases of imported air conditioners. However, the AER considers that while there would likely be some reduction in maximum demand as a result of the global economic downturn and worsening exchange rate, recent evidence indicates that summer peak demand is likely to continue to grow, despite the economic slow down.[298] The AER considers the revised forecasts make reasonable assumptions regarding customer responses to the economic downturn at peak times, given the recent record peak demands across the NEM.

EnergyAustralia's revised maximum demand forecasts

As noted in section 6.5.3, the AER engaged MMA to review EnergyAustralia's revised energy forecast. MMA also reviewed the methodology used by EnergyAustralia to incorporate anticipated retail price rises into its revised global peak demand forecast.[299]

MMA concluded that for non–residential customers, price elasticity of peak demand is likely to be similar to the price elasticity of energy demand.[300] This is contrary to EnergyAustralia's assumption that the elasticity of peak demand to price is not significant, unlike the elasticity of demand for energy which it assumed to be equal to –0.25 for residential customers, and –0.35 for non residential customers.[301]

294 AER, email to Country Energy requesting for information, 5 February 2009.
295 Country Energy, email response to the AER's request for information, 26 February 2009.
296 Country Energy, email response to the AER's request for information, 26 February 2009.
297 Country Energy, email response to the AER's request for information, 26 February 2009.
298 Sydney Morning Herald, *Power demand hits new high as mercury soars*, January 16 2009, <http://www.smh.com.au/news/environment/power-demand-hits-new-high-as-mercury-soars/2009/01/15/1231608886283.html>, accessed 11 March 2009.
299 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, 17 March 2009 (updated 17 April 2009), confidential, pp. 47–50.
300 MMA, *Final Report—Review of the revised EnergyAustralia forecasts*, confidential, p. 50.
301 EnergyAustralia, *Revised regulatory proposal*, attachment 13A, p. 12.

EnergyAustralia did not incorporate a price elasticity of demand into its revised peak demand forecasts.

MMA’s findings indicate EnergyAustralia’s revised global maximum demand forecast is likely to be conservative in its assumed peak demand price response, resulting in a higher global maximum demand forecast.[302] While the AER considers MMA’s findings are reasonable, it notes that the revised maximum demand forecast does not directly impact on its assessment of EnergyAustralia’s growth capex, as it does not incorporate revised spatial forecasts. This is also considered in chapter 7.

Impacts of the revised forecasts on capex

The AER notes the submissions from the EMRF, EUAA, Origin Energy and the PIAC relating to the expected impact on maximum demand and capex of the global economic downturn and rises in electricity prices over the next regulatory control period. In particular, the AER notes the EMRF’s submission that the fall in the value of the Australian dollar since the NSW DNSPs’ forecasts were prepared will result in fewer customers purchasing imported air conditioners.[303]

Each of the NSW DNSPs submitted revised capex proposals incorporating the anticipated impact of the worsening global financial crisis. Country Energy’s and EnergyAustralia’s revised maximum demand forecasts were prepared on a global, top–down basis, and did not include revisions to spatial forecasts, which are key drivers of growth capex. As such, the AER’s review of maximum demand has been limited to a high–level assessment of the reasonableness of the top–down revisions. However, the AER has thoroughly reviewed the DNSPs’ revised energy forecasts to ensure that the resulting inputs into the PTRM for determination of the X factors are appropriate. The AER’s consideration of the NSW DNSPs’ revised energy forecasts is provided in section 6.5.3, and consideration of the NSW DNSPs’ capex programs is outlined in chapter 7.

Uncertainty in economic outlook

The PIAC recommended that, due to the high level of uncertainty in the economy and in expected electricity prices over the next regulatory control period, the AER’s final determinations and associated demand forecasts should be reopened at a later date when more information is available.[304]

Clause 6.11.2 of the transitional chapter 6 rules states that the AER must publish its distribution determination not later than two months before the commencement of the next regulatory control period. This includes the AER’s decision on the DNSPs’ annual revenue requirements, for which maximum demand forecasts are an input, under clause 6.12.1(2) of the transitional chapter 6 rules. The AER cannot delay its decision on the reasonableness of the DNSPs’ demand forecasts. The NER does not contain a provision to allow the AER to re–open its determination due to inaccurate forecasts. While there are cost pass through provisions in the transitional chapter 6 rules, these relate to material changes in costs during the regulatory control period, not changes in volumes.

The AER notes EnergyAustralia’s revised regulatory proposal and submissions propose a G–factor amendment to the regulatory control mechanism as a potential way to manage

302 MMA, *Final Report—Review of the revised EnergyAustralia forecasts*, confidential, p. vii.
303 EMRF, pp. 11–12.
304 PIAC, p. 3.

uncertain energy forecasts.[305] The AER notes that this is inconsistent with transitional chapter 6 clause 6.2.5(c1)(1)(i), which requires that for the next regulatory control period, the control mechanism for standard control services must be substantially the same as that determined by the IPART for the current regulatory control period. Chapter 4 of this final decision provides further discussion on EnergyAustralia's proposed G–factor amendment.

While the AER notes the uncertainty surrounding economic growth forecasts and the likelihood of retail electricity price increases in the next regulatory control period, it considers that the global, top–down revisions made to the DNSPs' maximum demand forecasts and capex proposals provide reasonable forecasts for overall peak demand in the next regulatory control period.

Conclusion

The AER notes that the DNSPs' revised energy forecasts, considered in section 6.5.3, are substantially lower than the energy forecasts considered in the draft decision, due to forecast slower economic growth and anticipated increases in retail electricity prices. By contrast, the revisions made to Country Energy's and EnergyAustralia's global maximum demand forecasts to account for these circumstances have resulted in small reductions in the rate of growth in maximum demand. This is due to the differences in the relationship between economic growth, retail prices and maximum demand. However, the AER notes that the maximum demand forecasts were revised on a top–down basis only, and as such may not fully account for the changed environment since the draft decision. The AER considers the significant variance between the revised growth rates in energy and maximum demand to be an indication only of a short–run relationship and that over time price elasticity for maximum demand would be comparable with the price elasticity for energy, especially for non–residential customers.

That noted, the AER has analysed the specific changes made to the DNSPs' global maximum demand forecasts to incorporate the changed environment. Notwithstanding the reservations expressed above with respect to EnergyAustralia's application of price elasticity, the AER considers that Country Energy and EnergyAustralia's revised global maximum demand forecasts provide a reasonable expectation of overall, global demand for standard control services over the next regulatory control period. The AER notes that the DNSPs did not prepare revised spatial maximum demand forecasts, and as such the relevance of this assessment to the AER's assessment of required load driven capex is limited to a high–level assessment of reasonableness.

The AER notes that Integral Energy did not provide a revised maximum demand forecast but provided a revised capex proposal incorporating the worsening economic downturn.[306] The AER's consideration of Integral Energy's revised capex proposal is provided in chapter 7.

305 EnergyAustralia, *Revised regulatory proposal*, chapter 4.
306 Integral Energy, *Revised regulatory proposal*, appendix D.

6.5.2 Customer number forecasts

AER draft decision

The draft decision determined that EnergyAustralia's and Integral Energy's revised customer number forecasts (provided to the AER on 29 and 31 October 2008, respectively), were reasonable inputs into the PTRM.

The draft decision rejected Country Energy's customer number forecast, and requested a revised forecast for consideration in the final decision. The AER requested that the revised forecast of customer numbers use actual customer numbers as at 30 June 2008 as a starting point for the forecast, then increased according to the NIEIR recommended base case forecast for the next regulatory control period.

Revised regulatory proposals

Country Energy and Integral Energy each provided a revised customer number forecast, updated to account for the worsening global financial crisis and the latest customer number data.

EnergyAustralia did not provide a revised customer number forecast, noting the considerable uncertainty over the timing and magnitude of the forecast economic recovery in NSW.[307]

AER considerations

Country Energy

Country Energy's revised customer number forecast growth rates were developed by NIEIR, and applied to actual customer numbers as at 30 June 2008.[308] The forecast incorporated the impact of the global economic downturn and NIEIR's estimated dwelling construction projection for Country Energy's network area.

The AER considers that Country Energy's revised customer number forecast was developed using reasonable methodology, and the resulting forecast of customer numbers set out in table 6.2 is an appropriate input into the PTRM.

The AER notes that Country Energy's submission on the AER's draft determination identified a deferral of planned capex associated with the connection of new customers.[309] The AER's consideration of Country Energy's revised capex proposal is set out in chapter 7.

EnergyAustralia

The AER notes EnergyAustralia's concerns regarding uncertainty in the NSW economic outlook and difficulties with forecasting new customer connections and associated capex. The AER also notes that both Country Energy's and Integral Energy's January 2009 revised customer number forecasts were prepared separately by NIEIR, by updating an existing dwelling construction forecast model.

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[307] EnergyAustralia, *Revised regulatory proposal*, pp. 23–34 and 121.
[308] Country Energy, emails to the AER, 24 February 2009 and 21 April 2009.
[309] Country Energy, *Draft NSW distribution determination*, pp. 2–3.

EnergyAustralia expressed its view that it is not appropriate for it to update its customer number forecasts from the October 2008 forecasts, due to the current level of uncertainty surrounding dwelling approvals in NSW.[310]

The AER considers that in this particular circumstance, EnergyAustralia's decision not to revise its customer number forecast appears reasonable. While Country Energy and Integral Energy engaged NIEIR to provide updated customer number forecasts for each network using existing models, updating EnergyAustralia's customer number forecast would require research into dwelling approvals which EnergyAustralia has indicated is currently too uncertain. Accordingly, the AER maintains its draft decision that EnergyAustralia's October 2008 customer number forecast provides a reasonable estimate of customer numbers in the next regulatory control period.

Integral Energy

The draft decision accepted Integral Energy's customer number forecast provided on 31 October 2008. Integral Energy provided a second revised customer number forecast as part of its revised regulatory proposal in January 2009. The updated forecast included revisions resulting from the change in the economic outlook for the Australian economy since mid–2008, as reflected in official forecasts by Treasury, as well as anticipated electricity price rises associated with the CPRS.[311] Given the extraordinary change in circumstances within the economic environment and the likely significant increases in electricity prices associated with the CPRS, the AER has decided to consider the revised forecasts in making its determination.

Integral Energy's revised regulatory proposal outlined the changes made in revising its customer number forecasts:[312]

- incorporating audited 2007–08 WAPC information
- applying the NIEIR base–case customer number forecasts.

The AER considers that Integral Energy's revised customer number forecast was developed according to reasonable methodology, and the resulting forecast is an appropriate input into the PTRM.

6.5.3 Energy forecasts

AER draft decision

The AER considered EnergyAustralia's and Integral Energy's revised energy forecast methodologies (provided to the AER on 29 and 31 October 2008, respectively) were reasonable. However, the AER rejected the energy forecasts on the basis that they should be updated to take into account the most recent energy sales data for regulatory year 2007–08, for consideration in the final decision.

310 EnergyAustralia, *Revised regulatory proposal*, pp. 23–24.
311 The Treasury, *Updated Economic and Fiscal Outlook*, February 2009, <http://www.budget.gov.au/2008-09/content/uefo/html/index.htm>; and Australian Government, *Carbon Pollution Reduction Scheme—Australia's Low Pollution Future—White Paper*, December 2008.
312 Integral Energy, *Revised regulatory proposal*, p. 26.

The draft decision rejected Country Energy's energy forecast, and requested that it provide a revised forecast, updated to take into account the most recent energy sales data for regulatory year 2007–08 for consideration in the final decision.

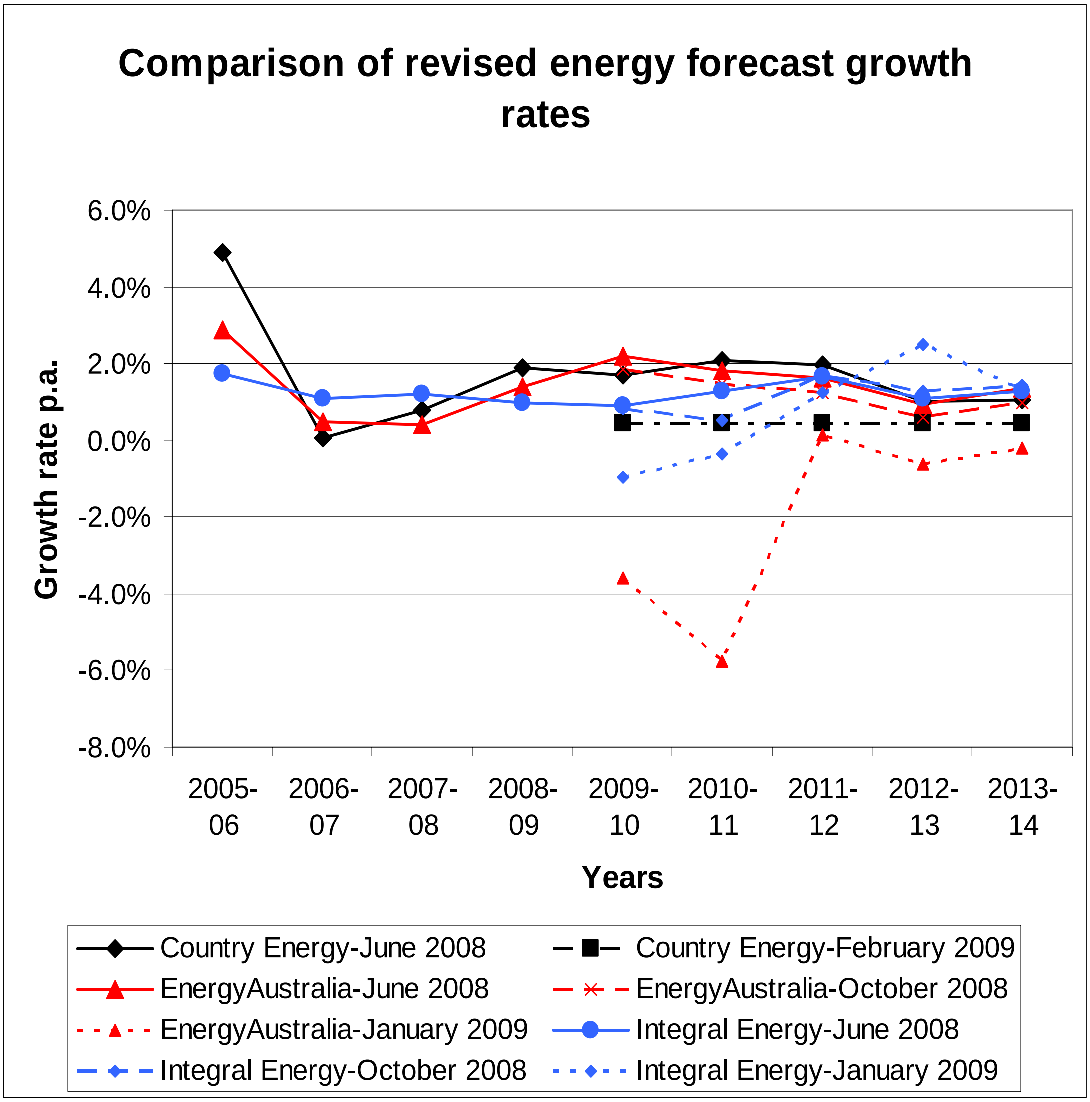
Revised regulatory proposals

As requested in the draft decision, the NSW DNSPs each provided a revised energy forecast, incorporating 2007–08 WAPC data which was subsequently reviewed by independent auditors.[313]

However, in addition to 2007–08 WAPC data, the revised forecasts also incorporated the impact of the worsening global financial crisis. Country Energy and EnergyAustralia also explicitly incorporated anticipated impacts of higher retail electricity prices on energy consumption. The resulting energy forecasts are significantly lower than the NSW DNSPs' original energy forecasts. Figure 6.1 illustrates the annual energy growth rates forecast by the NSW DNSPs.

313 The AER had anticipated that EnergyAustralia's and Integral Energy's energy forecasts would only be updated from the forecasts considered in the draft decision to account for any differences between the 2007–08 WAPC estimates (incorporated into the October 2008 forecasts) and audited 2007–08 WAPC actual data, which became available in February 2009. Similarly, the AER anticipated that Country Energy's forecast would only be updated from its June 2008 forecast to account for the latest WAPC data.

Figure 6.1: Comparison of revised energy forecast growth rates



Sources: Country Energy, *Regulatory proposal,* Regulatory proformas, confidential, table 2.3.8; Country Energy, *email to the AER,* 24 February 2009; EnergyAustralia, October forecast model (provided to the AER on 27 February 2009); EnergyAustralia, *Revised regulatory proposal,* Attachment 13A, table 1.1; Integral Energy, *Regulatory proformas*, confidential table 2.3.8; Integral Energy, *Forecasts for energy and customer numbers*, 31 October 2008 and Integral Energy, *Revised regulatory proposal*, Attachment 1, confidential.

MMA review of EnergyAustralia's revised energy forecast

As Figure 6.1 illustrates, the updated energy forecast provided in EnergyAustralia's revised regulatory proposal (January 2009 forecast) is significantly different from the:

- past 5 years of energy sales data
- revised forecast considered in the draft decision (October 2008)
- revised forecasts submitted by the other NSW DNSPs.

Accordingly, the AER engaged MMA to review EnergyAustralia's January 2009 revised energy forecast methodology and forecasts.

MMA's review was confined to the changes made to EnergyAustralia's June 2008 energy forecast methodology which was reviewed by MMA in September 2008. These changes resulted in the October 2008 forecast (considered in the draft decision), and also the January 2009 forecast.

Revised gross state product (GSP) forecast

At the conclusion of its review of EnergyAustralia's June 2008 energy forecast, MMA recommended to the AER that EnergyAustralia provide a revised forecast for consideration in the draft decision, using a more recent GSP forecast to account for the worsening global financial crisis.[314]

As recommended by MMA, EnergyAustralia's October 2008 forecast incorporated a June 2008 Econtech GSP forecast, which forecast average annual growth of 1.9 per cent over the next regulatory control period.[315] EnergyAustralia's January 2009 revised forecast incorporated an ANZ GSP forecast for regulatory years 2009–10, and an October 2008 Econtech GSP forecast for regulatory years 2010–14.[316] The resulting GSP forecast was for average annual growth of 2.5 per cent per annum over the next regulatory control period, which is higher than the GSP forecast assumed in the October 2008 revised forecast.

MMA concluded that the GSP forecasts applied in the January 2009 forecast are reasonable, but noted that EnergyAustralia's anticipated price increases, including increases associated with the CPRS, had by far the greater impact on its January 2009 forecast.[317] Accordingly, MMA focused its review on the anticipated price changes and their application to the forecast.

Anticipated price increases

MMA analysed the retail electricity price increases anticipated in the next regulatory control period. MMA's findings included:

- while EnergyAustralia assumed the introduction of the CPRS will add 18 per cent to the retail price of electricity from 2010, MMA considered this is likely to be reduced by the economic downturn lowering carbon prices. MMA also noted that EnergyAustralia's assumed price increase did not factor in the cessation of the NSW Greenhouse Gas Abatement Scheme. MMA concluded that the CPRS is likely to add approximately 13.5 per cent to the retail price from its introduction, which MMA also noted may be delayed[318]
- EnergyAustralia's assumed network use of system (NUOS) price increases resulting from the AER's determinations for the NSW DNSPs are not appropriately allocated between customer types, however MMA found that the resulting price increases are

314 MMA, *Final report—Regulatory proposal 2009 to 2014: review of EnergyAustralia's customer numbers and energy forecasts*, September 2008, confidential, p. viii.

315 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 45.

316 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 45.

317 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 46.

318 MMA noted that there is limited certainty regarding the timing of the introduction of the CPRS, as the Government does not have control of the Senate, and the Opposition has expressed its intention to vote against the scheme. MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, pp. 13–15.

reasonable. MMA also considered that retail price increases resulting from the AER's determination for TransGrid are likely to be insignificant[319]

- increases in DNSP levies resulting from the NSW Government mini–budget are likely to result in retail price increases of approximately 1.15 per cent[320]
- no retail price increases will result from the increases to coal levies, as these are unlikely to be passed onto electricity prices[321]
- falling energy prices since 2007–08 are likely to result in a 7.5 per cent reduction in large customers' retail electricity prices[322]
- the IPART March 2009 draft decision on market based electricity purchase cost allowances indicates that real retail electricity prices are likely to increase by 5.1 per cent in 2009–10 for small residential and non–residential low voltage customers consuming less than 160 MWh per year.[323]

Table 6.8 summarises MMA's findings on the likely retail electricity price increases over the next regulatory control period.

319 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, pp. 15–16.

320 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 17.

321 MMA stated that in competitive market, the ability of NSW coal generators to pass on the levy will be constrained by other generators' bidding. MMA also noted that the fuel cost of coal generators is related to the export price of coal, which is affected by international coal markets. MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 17.

322 MMA calculated this price reduction by estimating a likely number of electricity price contracts ending in 2009–10, where new contract prices are likely to be higher than existing contracts. MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 20.

323 This increase constitutes energy cost increases only. While IPART's draft decision incorporated network cost increases, these are included as a separate price effect in MMA's estimated price increases. MMA found that this price increase is largely the result of 2009–10 contract prices remaining high, due to uncertainty in the market. MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, pp.17–19; and IPART, *Market–based electricity purchase cost allowance—2009 review—Regulated electricity retail tariffs and charges for small customers 2007 to 2010*, March 2009.

Table 6.8: MMA's estimate of real retail price increases (annual percentage change)

Factor	2009–10	2010–11	2011–12	2012–13	2013–14
CPRS	–	13.5	–	–	–
AER Draft determination NUOS	7.9	4	4	4	4
NSW mini–budget DNSP levies increase	1.1	–	–	–	–
IPART March 2009 draft determination – small customers	5.1	–	–	–	–
Reduction in energy prices – larger customers	–7.5	–	–	–	–
Total real price change - small customers	14.1	17.5	4	4	4
Total real price change - larger customers	1.5	17.5	4	4	4

Source: MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 22.

Own–price elasticity of demand

MMA reviewed the own–price elasticity of demand for energy used by EnergyAustralia to determine customer responses to increased retail electricity prices. It noted that EnergyAustralia had superimposed elasticities derived by NIEIR onto its model, which is generally not considered good practice.[324]

MMA noted that NIEIR's derived elasticities are described by NIEIR as 'long–run' price elasticies.[325] MMA identified analysis completed by NIEIR in 2004, on behalf of the Electricity Supply Industry Planning Council (ESIPC), assessing the impact of large price increases in South Australia on energy demand.[326] ESIPC's report indicates that the appropriate application of the NIEIR elasticities is that they should be phased in over a number of years following the price impact.[327]

Using the ESIPC's results and assumptions, MMA estimated how the NIEIR elasticities should be phased in over a period of seven years, provided in table 6.9.

[324] This is because the rest of the model may change when the additional variable is added. MMA stated that assuming direct additivity of models is untested, and does not constitute best practice. MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. v.

[325] MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 33.

[326] ESIPC, *Sales forecasts by tariff category for South Australia's electricity distribution network for the period 2005-06 to 2009-10*, 14 September 2004, available at www.escosa.sa.gov.au

[327] ESIPC, *Sales forecasts by tariff category for SA's electricity distribution network*, pp. 15–17.

Table 6.9: MMA's estimate of phased price responses

Years after price change	0	1	2	3	4	5	6	7 and subsequent years
Elasticity impact	20%	40%	60%	78%	85%	91%	97%	100%

Source: MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 35.

MMA reviewed the elasticities derived by TransGrid in its model of electricity consumption in NSW. TransGrid's model assumed long–run real electricity price elasticity of demand of –0.15, which is approximately half of the NIEIR derived elasticities.[328] MMA stated that TransGrid's assumed elasticities are a reasonable alternative to those derived by NIEIR.[329]

MMA noted that ActewAGL's original energy forecast for the next regulatory control period relied on NIEIR's derived elasticities, however, following the release of the CPRS White Paper, ActewAGL revised its energy forecast, altering its assumed elasticities. ActewAGL's revised energy forecast included an elasticity of –0.2, reflecting its view that NIEIR's elasticities do not properly account for changes in the prices of alternative energy sources such as natural gas, meaning that the CPRS will result in less pronounced substitution away from electricity.[330] MMA considered that the impact of rising gas prices should be taken into account in EnergyAustralia's energy forecast, lowering overall additive elasticity.[331]

In conclusion, MMA noted the uncertainty surrounding the use of elasticities, and stated that it considers either the TransGrid or NIEIR elasticities may be suitable, however, it noted that it is not clear how the elasticities should be incorporated within the original EnergyAustralia forecast model. MMA stated that if the NIEIR elasticities are to be used, then it considers that their impact should be phased in line with the ESIPC's recommendations, and that the impacts of rising gas prices should also be taken into account.[332]

AER considerations

In reviewing the NSW DNSPs' revised energy forecasts, the AER considered the relative magnitude of the changes made to their forecasts since those considered in the draft decision. The AER also considered the changes made to the forecast methodologies that were reviewed and detailed in the draft decision, and the extent to which the DNSPs had complied with the requests made in the draft decision and determinations.

While the NSW DNSPs' provided revised forecasts using audited 2007–08 WAPC sales data, as requested in the draft decision, the revised forecasts also incorporated the impact

[328] NIEIR's assumed elasticities: residential customers –0.25, commercial customers –0.35, industrial customers –0.38. NIEIR, *The own price elasticity of demand for electricity in the NEM*, June 2007, p. 3.
[329] MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, pp. 32–33.
[330] ActewAGL, *Distribution determination 2009–14, Revised regulatory proposal to the AER*, January 2009, p. 42.
[331] MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 37.
[332] MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 37.

of the worsening global financial crisis. In addition, Country Energy and EnergyAustralia incorporated anticipated impacts of increasing electricity prices on energy demand.

The AER notes the submissions by the EMRF, the EUAA and Origin Energy that the NSW DNSPs October 2008 revised energy forecasts did not sufficiently account for the recent economic downturn. The global financial crisis has been portrayed as being the most serious economic event affecting developed economies since the great depression of the 1930s.[333] The AER considers that in addition to the economic downturn, the CPRS as outlined in the December 2008 White Paper could potentially have significant implications for demand for energy, and accordingly for NSW DNSP revenues and network charges. Given these extraordinary changes in circumstances, the AER considers it appropriate that the DNSPs accounted for such changes in their revised energy forecasts, despite this being contrary to the request for revised forecasts in the draft decision and determinations. The AER has reviewed the methods by which the DNSPs have accounted for such changes.

The EUAA submitted that the DNSPs' revised X factors are at odds with the current economic environment, and cannot be justified in an environment of worsening global economic decline.[334] The AER notes that there is an inverse relationship between energy sales and X factors calculated for a WAPC, and that by revising their energy forecasts downwards to incorporate the worsening economic downturn, the DNSPs' proposed X factors have increased. The AER appreciates the EUAA's concern that increasing electricity prices appear at odds with falling economic growth. The capital intensive nature of the DNSPs' expenditure means that costs are largely insensitive to short–run changes in demand. The consequence of this is that electricity prices will increase due to the need for DNSPs to recover revenues over fewer units of electricity sales. Accordingly, the AER has reviewed the NSW DNSPs' revised energy forecasts to determine their appropriateness as inputs into the PTRM.

Uncertainty

The AER notes that the NSW DNSPs' revised energy forecasts rely on highly uncertain assumptions, including the impact of the global economic downturn and the introduction of the CPRS. Stakeholders, the NSW DNSPs and MMA have each acknowledged the difficulties in forecasting in the current environment.[335] The AER has taken this uncertainty into account in considering the appropriateness of the resulting forecasts, noting that forecasts are limited by the reliability of the information upon which they rely. Given the range of views on NSW economic growth over the next regulatory control period the AER has reviewed the reasonableness of the NSW DNSPs' assumptions and methodologies, and the relative magnitude of the growth forecasts.

In considering the relative magnitude of the growth forecasts, the AER notes that EnergyAustralia's January 2009 revised energy forecast indicated that energy sales would decline by approximately 2 per cent per annum over the next regulatory control period, while the other ACT and NSW DNSPs had forecast slowed, but positive growth.[336]

[333] IMF, *World Economic Outlook*, October 2008.
[334] EUAA, p. 27.
[335] Origin Energy, p. 6; PIAC, p.3; and EnergyAustralia, *Submission other network providers*, p. 4.
[336] The AER also notes this forecast is for total energy sales in regulatory year 2013–14 to be 10 per cent less than total energy sales in 2008–09. The AER considers this is unlikely, and most likely results from adding a price effect into EnergyAustralia's model without removing double-counting.

The AER has also compared revisions made to EnergyAustralia's global maximum demand forecasts with revisions made to its energy forecasts. EnergyAustralia's January 2009 revised energy forecast implies that energy consumption in 2013–14 will be only 88 per cent of its original June 2008 forecast for 2009–10. By contrast, EnergyAustralia's revised global maximum demand forecast indicates that maximum demand in 2013–14 will be 8 per cent higher than its original June 2008 forecast for 2009–10.[337]

Impact of worsening global economic downturn

Country Energy's revised energy forecast was generated by NIEIR. The forecast was updated from its June 2008 forecast, incorporating NIEIR's reassessment of economic growth in Country Energy's region which relied on data available up to December 2008. NIEIR's resulting base–case forecast was for average annual economic growth in the Country Energy region of 1.2 per cent for the period 2009–18.[338]

EnergyAustralia's revised energy forecast incorporated average annual GSP growth of 2.5 per cent per annum over the next regulatory control period. This GSP forecast was developed using a combination of Econtech's October 2008 forecast and November 2008 ANZ Bank forecasts.[339] In contrast to the other NSW DNSPs, EnergyAustralia's GSP growth figure is an assessment for the whole of NSW, not just the EnergyAustralia network region. MMA considered that EnergyAustralia's GSP forecast is likely to be reasonable, as it is comparable to the latest Econtech forecast released in January 2009.[340] However, MMA found that in EnergyAustralia's energy forecast model, anticipated changes in retail electricity prices had a much greater impact on the overall revised energy forecast than changes in GSP. As such, the global financial crisis had little impact on the changes in EnergyAustralia's energy forecast.[341]

Integral Energy's revised energy forecast also incorporated a regional product forecast generated by NIEIR in December 2008. NIEIR's base–case forecast was for average annual growth in Integral Energy's region of 1.8 per cent over the next regulatory control period.[342]

The AER considered the discrepancies between the GSP and regional product forecasts used by the NSW DNSPs. The AER notes that both Country Energy and Integral Energy used forecasts generated specifically for their networks by an independent forecaster, NIEIR. The discrepancies between NIEIR's forecasts for these DNSPs is indicative of the high level of volatility in economic indicators at present, and the differences in the effect of the economic downturn on Integral Energy and Country Energy's network regions. The AER considers that both forecasts are reasonable.[343] The AER also notes MMA's

[337] EnergyAustralia, *Regulatory proposal,* Regulatory proformas, confidential, table 2.3.8; EnergyAustralia, *Revised regulatory proposal* – attachment 13A, tables 1.2 and 1.1; and EnergyAustralia, October forecast model (provided to the AER on 27 February 2009).

[338] Country Energy's revised regulatory proposal did not provide the detail to allow the AER to calculate the equivalent regional product growth rate for the next regulatory control period, however the AER considers it unnecessary for its analysis. Country Energy, *Revised regulatory proposal*, appendix A, p. 20.

[339] EnergyAustralia, *Revised regulatory proposal*, p. 121.

[340] MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, pp. 45–46. Econtech, *Australian National, State and Industry Outlook*, January 2009.

[341] MMA, Final *report—Review of the revised EnergyAustralia forecasts*, confidential, p. iii.

[342] Integral Energy, *Revised regulatory proposal*, table 4.4.

[343] In particular, the AER notes the considerable disparity between recent GSP forecasts prepared by Econtech. In June 2008, it forecast average annual GSP growth over the next regulatory control period to be 1.8 per cent, in October 2008 this forecast was 2.5 per cent, while in January 2009 it forecast

assessment that EnergyAustralia's GSP forecast is reasonable, and that EnergyAustralia's revised energy forecast was driven largely by anticipated retail price increases, rather than by changes in GSP. On balance, the AER considers the NSW DNSPs use of GSP forecasts is reasonable.

Electricity price rises over the next regulatory control period

Country Energy

Country Energy's revised energy forecast assumes that real electricity prices in NSW will be affected by:[344]

- regulatory reforms and rulings, including the AER and IPART's determinations
- more stringent greenhouse policies, including the CPRS
- the ownership and aggregation of generation assets
- new generation and transmission assets.

Country Energy's revised energy forecast assumes residential retail prices will increase by 23 per cent between 2007–08 and 2014–15, and that business retail prices will increase by 29 per cent over the same period.[345] The proportion of these price increases that is attributed to each driver is not apparent within Country Energy's revised regulatory proposal, however, the AER considers that the overall anticipated price increase does not appear unreasonable, particularly given MMA's findings on likely NSW retail price rises over the next regulatory control period, as outlined above.

EnergyAustralia

As noted above, EnergyAustralia's revised energy forecast incorporates electricity price rises resulting from a range of variables, including:

- the introduction of the CPRS
- outcomes of the AER's draft determinations for EnergyAustralia and TransGrid
- outcomes of IPART's retail price determination (made in July 2007)
- increases in DNSP levies and coal royalties stipulated in the NSW Government's November 2008 mini–budget.

In total, EnergyAustralia has anticipated that retail electricity prices will rise from current levels by 54 per cent by the end of the next regulatory control period.[346] MMA analysed the price increases assumed by EnergyAustralia, and concluded that retail electricity

growth of 2.1 per cent. The fluctuations in NSW GSP forecasts indicate that there is significant uncertainty. Econtech, *Australian National, State and Industry Outlook*, June 2008, October 2008 and January 2009.

344 Country Energy, *Revised regulatory proposal*, appendix A, p. 43.

345 Derived from: Country Energy, *Revised regulatory proposal*, appendix A, table 5.3, p. 43.

346 EnergyAustralia's revised regulatory proposal stated that it had assumed retail prices will increase by a compound total of 65% (EnergyAustralia, *Revised regulatory proposal*, p. 119). MMA considered that as many of the price increases relate to absolute changes, such as the imposition of a CPRS, prices in most cases will not compound. Accordingly, MMA summarised the expected price changes by adding rather than compounding the percentage increases. MMA, *Final report—Review of the revised EnergyAustralia forecasts*, p. 12.

prices for large customers are likely to increase from current levels by 31 per cent, and small customers by 44 per cent by the end of the next regulatory control period.[347]

Integral Energy

While Country Energy and EnergyAustralia directly accounted for demand responses to anticipated rises in retail electricity prices, Integral Energy incorporated this price effect indirectly into its forecasts through its modelling of average residential customer appliance usage and the anticipated effect of price increases on GSP.[348]

In its January 2009 forecast, Integral Energy did not update its estimate of the impact of retail electricity price increases on residential customer energy consumption from that which was incorporated into its October 2008 energy forecast. Integral Energy's October 2008 residential energy forecast model incorporated an appliance energy efficiency improvement in projected consumption.[349] This factor incorporated the impact of increasing retail electricity prices on average usage per residential customer.

For non–residential customers, Integral Energy's forecast incorporated the effect of anticipated retail price increases on GSP, which was updated for the January 2009 revised energy forecast.[350] The AER considers Integral Energy's revised energy forecast reasonably accounts for expected increases in retail electricity prices in the next regulatory control period.

AER consideration of retail price increases

The AER notes the recent uncertainty surrounding the introduction of the CPRS, in particular given the economic downturn caused by the global financial crisis. MMA highlighted the fact that the Australian Government does not currently hold power in the Senate, and that the Opposition has expressed its intention to vote against the CPRS when it is proposed.[351] The AER is not able to withhold its decision on appropriate energy forecasts for the next regulatory control period until a decision on the CPRS is made, but notes the possibility that the CPRS will not be applied in the form considered within the December 2008 White Paper. Accordingly, the AER considers it is appropriate to apply some conservatism in assuming the impacts of the CPRS on energy consumption.

EnergyAustralia has incorporated into its revised energy forecast a rise in retail electricity prices reflecting its proposed expenditure and the AER's determinations on its and TransGrid's revenues for the next regulatory control period. The AER considers this is reasonable.

With the release of IPART's draft decision on market–based electricity purchase cost allowances for 2009–10 in March 2009, the AER considered the likely impact of IPART's determinations on the NSW DNSPs' energy forecasts. The AER notes that while Country Energy's revised energy forecast incorporated the impact of regulatory reforms and rulings, Integral Energy did not anticipate the AER's or IPART's regulatory determinations in generating its revised energy forecast. EnergyAustralia incorporated a

[347] MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. v.
[348] Integral Energy, *Revised regulatory proposal*, p. 21 and Integral Energy, email to the AER, 23 March 2009.
[349] Integral Energy, email to the AER, 23 March 2009.
[350] Integral Energy, email to the AER, 23 March 2009.
[351] MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, pp. 14–15.

5 per cent increase in retail electricity prices in anticipation of IPART's determination.[352] MMA reviewed IPART's draft decision, and calculated that it would result in a 5.1 per cent increase in electricity prices for small residential and non–residential low voltage customers in NSW, in addition to any network charge increase.[353] The AER considers that MMA's estimate of the retail price increase resulting from IPART's draft decision is reasonable. EnergyAustralia's and Country Energy's January 2009 forecasts incorporated this retail price rise, which the AER considers is reasonable. As noted above, Integral Energy did not update its estimate of the impact of retail electricity price increases on energy consumption for its January 2009 forecast.

EnergyAustralia's January 2009 revised energy forecast incorporated a direct increase in retail electricity prices resulting from an increased coal levy imposed by the NSW mini–budget.[354] The AER considers that this price increase is unlikely. As noted by MMA, the ability of coal generators to pass on the increased costs is constrained by the bidding of other generators and the international coal market price, which is being driven down by the global economic downturn.[355] The AER considers it is not appropriate to incorporate an anticipated price increase and demand response due to the increased coal levies into energy forecasts for the next regulatory control period.

EnergyAustralia also incorporated an anticipated retail price rise due to increases in DNSP levies resulting from the NSW mini–budget. The AER considers it is reasonable to assume that this DNSP cost increase will be passed through to retail prices, and notes that subsequent to EnergyAustralia submitting its January 2009 revised forecast, the NSW Government indicated that further rises in DNSP levies were to be recovered from customers in the next regulatory control period, increasing the EnergyAustralia levy that was outlined in its revised regulatory proposal from $48 million per annum to $61 million per annum. MMA has incorporated this increase in EnergyAustralia's DNSP levies into its assessment of likely price increases for the next regulatory control period.[356] Country Energy and Integral Energy have not indicated to the AER that they are facing increased DNSP levies in the next regulatory control period.

The AER considers MMA's analysis of the anticipated rises in retail electricity prices over the next regulatory control period to be reasonable. The AER notes that MMA's estimates of total retail price increases for small and large customers are significantly lower than EnergyAustralia's assumed price increases.[357]

The AER considers that Country Energy's and Integral Energy's energy forecasts have reasonably accounted for increases in retail electricity prices in the next regulatory control period.

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352 EnergyAustralia, *Revised regulatory proposal*, attachment 13A, p. 22.

353 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, pp. 18–19.

354 EnergyAustralia, *Revised regulatory proposal*, attachment 13A, pp. 21–22.

355 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 17.

356 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 21.

357 EnergyAustralia incorporated an assumed retail price increase of 54 per cent for both small and large customers over the next regulatory control period. MMA has estimated this increase is likely to be 31 per cent for large customers and 44 per cent for small customers. The AER notes that Country Energy's assumed price increases are lower than MMA's estimates. However, Country Energy's estimates are for residential and business customers, while MMA has calculated price increases for small and large customers. MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. v and Country Energy, *Revised regulatory proposal*, appendix A, p. 43.

Own–price elasticity of demand

In forecasting a demand response to rising electricity prices over the next regulatory control period, EnergyAustralia applied NIEIR's derived elasticities of –0.25 for residential customers and –0.35 for non-residential customers to its revised forecast model.[358] EnergyAustralia's June and October 2008 energy forecasts did not incorporate anticipated electricity prices or demand responses, as EnergyAustralia indicated that there was too much uncertainty at those times to determine likely prices over the next regulatory control period.[359]

The key drivers of EnergyAustralia's June 2008 and October 2008 energy forecasts were customer number growth, average residential customer usage and economic growth.[360] With the release of the CPRS White Paper in December 2008, and the NSW Government mini–budget and the AER's draft determinations in November 2008, EnergyAustralia decided that there was sufficient certainty for it to forecast retail electricity prices. It did so by applying NIEIR's derived elasticities to convert the price rises into energy sales.[361] When anticipated price increases (and customer demand responses) were added directly into EnergyAustralia's energy model, they became by far the key driver of energy consumption on its network, having a much greater impact on the forecast than GSP. As noted in section 6.5.2, EnergyAustralia did not revise its customer number forecast from that provided in October 2008, which is an input into its energy forecasts. The key changes in EnergyAustralia's energy forecast from its October 2008 forecast result from reductions in average usage per customer, driven by increases in retail electricity prices.

MMA reviewed EnergyAustralia's June 2008, October 2008 and January 2009 energy forecasts, and concluded that it was not good methodological practise for EnergyAustralia to simply apply NIEIR's derived elasticities to its forecast model. In particular, MMA noted EnergyAustralia's non-residential model is characterised by GSP alone (and not price), and that EnergyAustralia did not provide evidence of a relationship between consumption, GSP and electricity price. MMA's own research suggests incorporation of a price term into an energy forecast model is expected to also change the coefficient of the GSP term. However, EnergyAustralia's revised forecast did not incorporate this change.[362]

MMA stated that the practice of superimposing price elasticities derived using one model onto a completely different model, results in changes in other model parameters and likely double counting of price effects.[363] MMA stated that EnergyAustralia needed to statistically re–estimate its forecast model, and incorporate price as a parameter.[364] MMA also noted that EnergyAustralia also did not take into account the impact of likely gas price rises associated with the CPRS.[365]

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358 NIEIR, *The own price elasticity of demand for electricity in the NEM*, June 2007.

359 The AER notes that EnergyAustralia appears to consider there is still too much uncertainty for it to revise its customer number forecast from that which was prepared in October 2008.

360 AER, *Draft decision*, p. 88.

361 EnergyAustralia, *Revised regulatory proposal*, p. 117.

362 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 28.

363 MMA stated that EnergyAustralia would have needed to rebuild its appliance model, with prices explicitly taken into account, to determine the impact of the double counting on its forecast. MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 29.

364 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, pp. 23–28.

365 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 28.

The AER considers the methodological changes made to EnergyAustralia's model resulted in an unrealistic energy forecast. However, the AER acknowledges that EnergyAustralia's options for incorporating a price response into its energy model were limited by the time frame to prepare its revised regulatory proposal, and that it explicitly selected publicly available price elasticities generated by a respected forecaster. As EnergyAustralia had not attempted to incorporate the demand response of electricity price changes into its earlier forecasts, due to the uncertainty at those times, EnergyAustralia was not able to sufficiently test its model to determine whether double counting was occurring.

Given MMA's findings on the application of NIEIR's elasticities to EnergyAustralia's model, and the magnitude of the reduction in EnergyAustralia's energy forecast since its October 2008 forecast (as outlined in figure 6.1 above), the AER considers EnergyAustralia's January 2009 revised energy forecast is likely to understate energy consumption for the next regulatory control period. The AER notes that EnergyAustralia's January 2009 revised energy forecast indicated that energy consumption would decline by approximately 2 per cent per annum over the next regulatory control period, while the other ACT and NSW DNSPs had forecast slower, but positive growth. The AER also notes EnergyAustralia's January 2009 forecast is for total energy sales in regulatory year 2013–14 to be 10 per cent less than total energy sales in 2008–09. The AER considers this is unlikely, and results from the poor methodological practice of adding a price effect into EnergyAustralia's model without removing double–counting.

NIEIR's price elasticities were estimated using data over the period 1980–1995. EnergyAustralia stated that the elasticities may now be outdated due to higher levels of gas penetration in the NEM, meaning there is less scope for price induced fuel switching.[366] MMA considered that TransGrid's derived elasticity, which incorporates the effect of rising gas prices, was a reasonable alternative to the NIEIR elasticities.[367] ActewAGL's revised regulatory proposal noted that NIEIR's elasticities are point estimates, which ActewAGL considered were inappropriate for application to large price increases such as those associated with the CPRS.[368] MMA noted that NIEIR's elasticities were described by NIEIR as long–run price elasticities, which could be assumed to apply in full only after 10 years of price increases, rather than in the first year of higher prices as assumed by EnergyAustralia.[369]

The AER considers there is limited availability of data and research into price elasticity of demand in the NEM, and notes the disparity of views on the appropriate elasticity of demand to apply to energy forecasts in this case. However, the AER agrees with EnergyAustralia that, given NIEIR's elasticities are publicly available and were generated using data from around the NEM, these elasticities can provide a basis for forecasting the impact of price increases on energy consumption in this case.

The AER considers that the further research carried out by NIEIR and reported by ESIPC can be applied to EnergyAustralia's forecast methodology. This would result in a gradual phasing in of elasticities over the next regulatory control period, and will offset some of

366 EnergyAustralia, *Revised regulatory proposal*, attachment 13A, p. 15.
367 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, pp. 32–33.
368 ActewAGL, *Revised regulatory proposal*, p. 42.
369 MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 33.

the problems with the application of the NIEIR derived elasticities to EnergyAustralia's forecast model, outlined above.[370] Accordingly, the AER considers that for application to EnergyAustralia's model, the NIEIR elasticities should be applied in accordance with NIEIR's analysis for the ESIPC, outlined in table 6.9.

The AER notes that the resulting energy forecast is likely to be conservative, as it does not account for the rising price of gas, a concern which both ActewAGL and MMA raised during the course of this review.[371] The AER also notes that this revision to EnergyAustralia's forecast is in place of a more extensive review of its forecast model to determine the appropriate way to incorporate a price response, which until the January 2009 forecast had been explicitly excluded from EnergyAustralia's forecast model. As there is limited time in which to prepare a forecast, the AER considers this amendment to the application of elasticity in EnergyAustralia's forecast is the most appropriate course of action.

In contrast, Country Energy's revised energy forecasts were generated by NIEIR using a methodology that was assessed by the AER prior to the draft decision, and considered reasonable. NIEIR incorporated a retail electricity price impact into its forecast model for Country Energy at the time of constructing the model. Also, NIEIR applied its own derived elasticities to its model for Country Energy's region, which is likely to be appropriate given both the forecast model and elasticities were derived and tested by NIEIR. The AER considers that the application of price elasticities to Country Energy's energy forecast is appropriate as the forecast model was generated by an independent forecaster which also derived and tested the elasticities. However, the AER notes that the fine details of NIEIR's processes are not transparent.

Integral Energy did not explicitly forecast customer demand responses to retail electricity prices for the next regulatory control period, rather it incorporated the general impact of increasing retail electricity prices on average residential customer appliance usage and GSP. The AER considers this is a reasonable approach, and the resulting forecast is reasonable.

EnergyAustralia's modelling of the AER's conclusions

On 30 March 2009, the AER requested that EnergyAustralia provide a revised energy forecast, applying the following changes to its forecast methodology:

- adopting MMA's recommended forecast retail price increases
- phasing in of NIEIR's elasticities according to MMA's analysis.

On 9 April 2009, EnergyAustralia provided a revised energy forecast (April 2009 forecast), incorporating the MMA's recommendations, outlined in table 6.10.

370 The AER considers that the likely problems associated with EnergyAustralia assuming direct additivity of its model, and the double counting of price effects (as outlined above in MMA's review section) has resulted in a low, conservative energy forecast. Applying the ESPIC's phasing of NIEIR's elasticities to EnergyAustralia's forecast is likely to increase the energy forecast, offsetting these effects. MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, p. 29.

371 ActewAGL, *Revised regulatory proposal*, p. 42 and MMA, *Final report—Review of the revised EnergyAustralia forecasts*, confidential, pp. 36–37.

EnergyAustralia also provided comments on MMA's final report, and identified a number of minor errors. MMA subsequently amended its report to correct the errors, however, it did not make any changes to its conclusions.[372]

Table 6.10: EnergyAustralia's energy forecasts 2009–14 (GWh)[a]

	2009–10	2010–11	2011–12	2012–13	2013–14	Average annual growth 2009–14[b]
Original forecast (June 2008)	28 466	28 986	29 455	29 736	30 136	1.6%
Revised forecast (October 2008)	28 350	28 766	29 128	29 298	29 582	1.2%
Revised forecast (January 2009)	26 663	25 132	25 172	25 017	24 968	–2.0%
Revised forecast (April 2009)	27 948	28 041	27 989	27 673	27 477	–0.1%

Source: EnergyAustralia, October forecast Model (provided to the AER on 27 February 2009); EnergyAustralia, *Revised regulatory proposal,* Attachment 13A (January 2009) table 1.1; EnergyAustralia, Letter to the AER—Revised January 2009 energy forecasts incorporating EnergyAustralia's comments on MMA report, 9 April 2009.

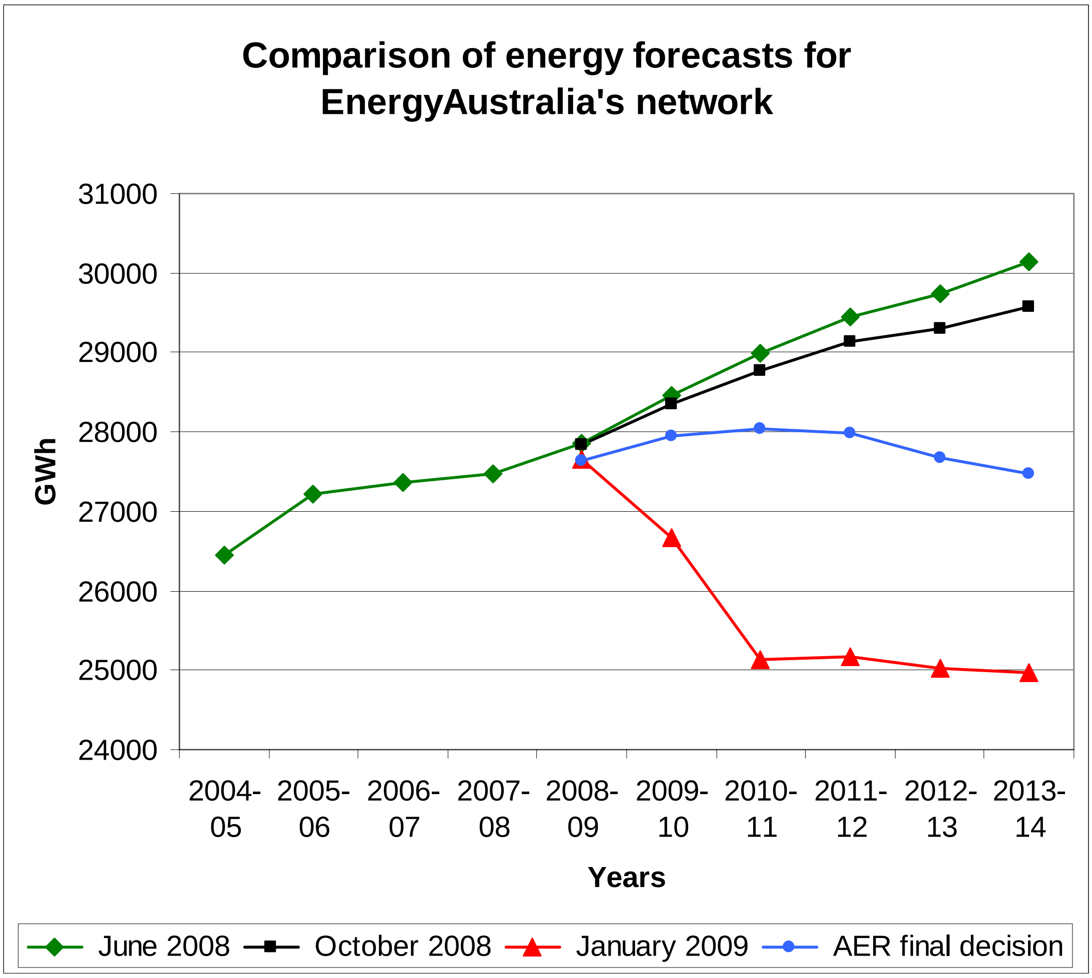
(a) The AER notes that the figures in table 6.7 of its draft decision included some large customer loads that are typically excluded from energy forecasts. The figures in the table 6.10 do not include these loads.

(b) Average annual growth rate includes growth from year 2008–09.

Figure 6.2 compares EnergyAustralia's June 2008, October 2008 and January 2009 energy forecasts with EnergyAustralia's modelling of the AER's conclusions.

372 EnergyAustralia, Letter to the AER—*Revised January 2009 energy forecasts incorporating EnergyAustralia's comments on MMA report*, 9 April 2009 and MMA, email to the AER, 17 April 2009.

Figure 6.2: Comparison of energy forecasts for EnergyAustralia's network



Source: EnergyAustralia, October forecast model (provided to the AER on 27 February 2009); EnergyAustralia, *Revised regulatory proposal*, Attachment 13A, table 1.1 and EnergyAustralia, Letter to the AER—*Revised January 2009 energy forecasts incorporating EnergyAustralia's comments on MMA report*, 9 April 2009.

The AER considers that the revised energy forecast provided by EnergyAustralia on 9 April 2009 provides a reasonable expectation of energy consumption for the next regulatory control period.

6.6 AER conclusion

For the reasons discussed above, the AER is satisfied that the revised global maximum demand forecasts provided by Country Energy and EnergyAustralia are reasonable. However, the AER notes that the forecasts have limited application for the AER's assessment of the revised capex proposals as they were not prepared on a spatial basis. Integral Energy did not provide a revised maximum demand forecast.

For the reasons discussed above, the AER is satisfied that the revised customer number forecast provided by Country Energy on 24 February 2009, and Integral Energy in its revised regulatory proposal, are appropriate inputs into the PTRM. The AER maintains its draft decision that EnergyAustralia's customer number forecast provided to the AER on 29 October 2008 is an appropriate input into the PTRM.

For the reasons discussed above, the AER is satisfied that the revised energy forecasts provided by Country Energy on 24 February 2009, and Integral Energy in its revised regulatory proposal, are appropriate inputs into the PTRM.

For the reasons discussed above, the AER is satisfied that the revised energy forecast, based on the AER's conclusions, provided by EnergyAustralia on 9 April 2009 is an appropriate input into the PTRM.

6.7 AER determination

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the other appropriate amounts, values or inputs with respect to energy and customer number forecasts for Country Energy are those that were provided to the AER on 24 February 2009, and outlined in tables 6.2 and 6.3 of this final decision.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the other appropriate amounts, values or inputs with respect to energy forecasts for EnergyAustralia are those that were provided to the AER by EnergyAustralia on 9 April 2009, and outlined in table 6.10 of this final decision.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the other appropriate amounts, values or inputs with respect to customer number forecasts for EnergyAustralia are those that were provided by EnergyAustralia to the AER on 29 October 2008, and were contained within table 6.7 of the draft decision.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the other appropriate amounts, values or inputs with respect to energy and customer number forecasts for Integral Energy are those that were provided in Integral Energy's revised regulatory proposal on 16 January 2009, and outlined in tables 6.6 and 6.7 of this final decision.

7 Forecast capital expenditure

7.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision. It sets out the AER's conclusions on forecast capex allowances for the NSW DNSPs for the next regulatory control period. It also:

- provides a general overview of the revised regulatory proposals
- lists comments made by stakeholders on the revised regulatory proposals
- summarises the AER's main considerations and responses to stakeholder comments.

The AER's conclusions and the estimates of the forecast capex allowances for the NSW DNSPs during the next regulatory control period are set out in section 7.6 of this chapter. The NSW DNSPs' revised input cost escalators and the AER's consideration of these are outlined in appendix L of this final decision. This chapter is to be read in conjunction with appendix L.

7.2 AER draft decision

Country Energy

The AER reviewed Country Energy's proposed forecast capex allowance of $4008 million ($2008–09) and did not consider the forecast capex allowance satisfied the capex criteria of the transitional chapter 6 rules.[373]

The AER considered that the expenditure associated with Country Energy's application of input cost escalators did not reflect a realistic expectation of the cost inputs required to achieve the capex objectives.[374] The AER also considered that Country Energy's forecast IT expenditure was unjustifiably high in comparison to other DNSPs, based on benchmark analysis.[375]

The draft decision on Country Energy's forecast capex is set out in table 7.1.

Table 7.1: AER draft decision on Country Energy's capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy proposed capex	752.0	779.0	806.0	822.0	849.5	4008.4
Total adjustments	–9.5	–2.2	–6.1	–12.6	–22.7	–53.0
AER capex allowance	742.6	776.8	799.9	809.3	826.7	3955.4

Source: AER, *Draft decision*, p. 152.
Note: Totals may not add up due to rounding.

373 AER, *Draft decision*, pp. 457–458.
374 AER, *Draft decision*, p. 436.
375 AER, *Draft decision*, p. 454.

EnergyAustralia

The AER reviewed EnergyAustralia's proposed forecast capex allowance of $8659 million ($2008–09). The AER did not consider that all proposed capital projects and programs, specifically EnergyAustralia's 'black spot' reliability program, were consistent with the capex objectives in the transitional chapter 6 rules.[376] The AER also considered that EnergyAustralia's proposed capex for the replacement of feeders 908 and 909 did not comply with the transitional chapter 6 rules.[377]

Overall, the AER considered EnergyAustralia's forecast capex allowance did not satisfy the capex criteria of the transitional chapter 6 rules.[378] The AER considered that the expenditure associated with EnergyAustralia's application of input cost escalators did not reflect a realistic expectation of the cost inputs required to achieve the capex objectives.[379]

The draft decisions on EnergyAustralia's forecast capex allowances are set out in tables 7.2 and 7.3.

Table 7.2: AER draft decision on EnergyAustralia's distribution capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia proposed capex	1319.7	1432.8	1611.2	1483.6	1533.3	7380.6
Total adjustments	–19.7	–31.1	–48.0	–50.2	–73.7	–222.7
AER capex allowance	1300.0	1401.8	1563.1	1433.4	1459.6	7157.9

Source: AER, *Draft decision*, p. 153.
Note: Totals may not add up due to rounding.

Table 7.3: AER draft decision on EnergyAustralia's transmission capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia proposed capex	264.2	170.5	266.6	346.7	229.9	1278.0
Total adjustments	–0.3	8.3	–1.7	–7.0	–0.5	–1.1
AER capex allowance	264.0	178.9	264.9	339.7	229.3	1276.8

Source: AER, *Draft decision*, p. 153.
Note: Totals may not add up due to rounding.

Integral Energy

The AER reviewed Integral Energy's proposed forecast capex allowance of $2953 million and considered that the forecast capex allowance did not satisfy the capex criteria of the transitional chapter 6 rules. Specifically, the AER considered that Integral

376 AER, *Draft decision*, p. 494.
377 AER, *Draft decision*, pp. 494–496.
378 AER, *Draft decision*, p. 499.
379 AER, *Draft decision*, p. 474.

Energy's proposed replacement capex did not reflect the efficient costs required to achieve the capex objectives.[380]

Further, the AER considered the expenditure associated with Integral Energy's application of input cost escalators did not reflect a realistic expectation of the cost inputs required to achieve the capex objectives.[381]

The draft decision on Integral Energy's forecast capex allowance is set out in table 7.4.

Table 7.4: AER draft decision on Integral Energy's forecast capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Integral Energy's proposal	573.9	641.5	610.4	582.5	544.3	2952.7
Total adjustments	–2.0	–3.5	–4.1	–6.9	–22.5	–39.1
AER's capex allowance	571.9	638.0	606.3	575.5	521.9	2913.7

Source: AER, *Draft decision*, p. 154.
Note: Totals may not add up due to rounding.

7.3 Revised regulatory proposals

Country Energy

Country Energy's revised regulatory proposal included a capex allowance of $4047 million ($2008–09) for the next regulatory control period.[382]

Following submission of its revised regulatory proposal, Country Energy reviewed its growth capex forecasts in light of its revised demand forecasts.[383] It identified deferral opportunities for domestic and commercial subdivision capex and made a submission proposing a reduction to its revised forecast capex allowance of $58 million.[384]

Country Energy's revised capex is set out in table 7.5.

380 AER, *Draft decision*, p. 528.
381 AER, *Draft decision*, pp. 512–513.
382 Country Energy, Global capex model, 10 February 2009.
383 Country Energy, *Draft NSW distribution determination*, February 2009, pp. 2–3.
384 Country Energy, *Draft NSW distribution determination*, p. 3.

Table 7.5: Country Energy's revised capex proposal ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Original capex	752.0	779.0	806.0	822.0	849.5	4008.4
Revised capex (including growth adjustments)	743.4	792.6	813.7	811.0	828.7	3989.3
Difference	–8.6	13.6	7.7	–11.0	–20.8	–19.2

Source: Country Energy, Global capex model, 10 February 2009 and Country Energy, Global capex model, 8 July 2008.
Note: Totals may not add up due to rounding.

Country Energy's revised regulatory proposal implemented the findings of the draft decision in respect of forecast capex, except those related to:[385]

- non–system IT expenditure
- real cost escalators
- adjustments to non–system land and buildings expenditure.

Country Energy's revised capex proposal of $3989 million ($2008–09) is approximately $19 million lower than its original capex proposal. Table 7.6 shows the annual profile of Country Energy's revised capex proposal by category.[386]

Table 7.6: Country Energy's revised capex proposal by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Asset renewal and replacement	138.3	156.6	168.3	174.9	181.7	819.8
Growth	239.6	267.1	284.0	292.1	300.1	1382.8
Reliability and quality enhancement	165.7	180.8	188.2	189.4	190.1	914.3
Environmental, safety and statutory obligations	35.8	39.9	42.5	43.7	44.9	206.7
Total system	579.4	644.4	683.0	700.0	716.7	3323.7
Non–system assets	164.0	148.1	130.7	111.0	111.9	665.6
Total	743.4	792.6	813.7	811.0	828.7	3989.3

Source: Country Energy, Global capex model, 10 February 2009.
Note: Totals may not add due to rounding.

385 Country Energy, *Revised regulatory proposal*, pp. 35–36.
386 Country Energy, Global capex model, 10 February 2009.

EnergyAustralia

EnergyAustralia's revised regulatory proposal included a capex allowance of $8303 million ($2008–09) for the next regulatory control period (excluding equity raising costs).[387] Tables 7.7 and 7.8 set out EnergyAustralia's revised capex for distribution and transmission.

Table 7.7: EnergyAustralia's revised distribution capex proposal ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Original capex	1319.7	1432.8	1611.2	1483.6	1533.3	7380.6
Revised capex	1292.7	1398.4	1501.8	1420.2	1437.3	7050.4
Difference	–27.0	–34.4	–109.4	–63.3	–96.0	–330.1

Source: EnergyAustralia, RIN templates and Revised RIN templates.
Note: Numbers may not add up due to rounding.

Table 7.8: EnergyAustralia's revised transmission capex proposal ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Original capex	264.2	170.5	266.6	346.7	229.9	1278.0
Revised capex	271.9	180.4	256.6	336.0	207.7	1252.6
Difference	7.7	9.9	–10.0	–10.8	–22.2	–25.4

Source: EnergyAustralia, RIN templates and Revised RIN templates.
Note: Numbers may not add up due to rounding.

EnergyAustralia revised its capex allowance to include revised peak demand forecasts. The updated peak demand forecasts take account of EnergyAustralia's estimate of the impact of the Carbon Pollution Reduction Scheme (CPRS) and lower economic growth forecasts. The inclusion of the updated peak demand forecast reduced EnergyAustralia's proposed capex allowance by $234 million.[388]

EnergyAustralia's revised regulatory proposal implemented the findings of the draft decision regarding:[389]

- a reduction of $8 million ($2008–09) for feeders 908 and 909
- a reduction of $145 million ($2008–09) for cost escalation adjustments, including the correction of errors made in the application of its cost escalators.

EnergyAustralia increased its revised capex by $30 million ($2008–09) because it considered that the draft decision on the re–assignment of its customers from one tariff class to another would restrict the application of tariff based demand management.

387 EnergyAustralia, *Revised regulatory proposal*, p. 21.
388 EnergyAustralia, *Revised regulatory proposal*, p. 26.
389 EnergyAustralia, *Revised regulatory proposal*, p. 21.

EnergyAustralia's revised capex proposal did not implement the findings of the draft decision regarding the:

- 'black spot' network reliability program[390]
- zone substation expenditure.[391]

EnergyAustralia's revised capex proposal of $8303 million ($2008–09) is approximately $356 million lower than its original capex proposal. Tables 7.9 and 7.10 show EnergyAustralia's revised capex by category for its distribution and transmission assets.

Table 7.9: EnergyAustralia's revised distribution capex by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Asset renewal/replacement	470.4	571.9	620.2	638.0	763.0	3063.5
Growth (demand related)	482.6	565.0	527.4	519.6	474.0	2568.6
Reliability and quality of service enhancement	52.2	76.6	129.9	66.7	33.6	358.9
Environmental, safety, statutory obligations	60.2	57.4	93.1	99.9	73.5	384.2
Other	35.6	27.8	36.2	22.0	22.8	143.4
Sub–total	1100.0	1298.7	1406.9	1346.2	1366.8	6518.7
Non–system assets	192.6	99.7	94.9	74.0	70.5	531.8
Total	1292.7	1398.4	1501.8	1420.2	1437.3	7050.4

Source: EnergyAustralia, RIN templates and revised RIN templates.
Note: Totals may not add due to rounding.

390 EnergyAustralia, *Revised regulatory proposal*, p. 37.
391 EnergyAustralia, *Revised regulatory proposal*, p. 39.

Table 7.10: EnergyAustralia's revised transmission capex by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Augmentation	73.4	79.6	56.7	71.8	65.5	347.0
Replacement	161.1	66.4	126.9	162.7	90.8	607.8
Reliability	2.0	0.8	44.2	80.0	34.7	161.8
Compliance	7.6	19.2	15.2	10.7	6.6	59.3
Sub–total	244.1	166.0	242.9	325.3	197.6	117.6
Non–system assets	27.7	14.4	13.7	10.7	10.1	76.6
Total	271.9	180.4	256.6	336.0	207.7	1252.6

Source: EnergyAustralia, RIN templates and revised RIN templates.
Note: Totals may not add up due to rounding.

Integral Energy

Integral Energy's revised regulatory proposal included a capex allowance of $2735 million ($2008–09) for the next regulatory control period.[392] Integral Energy's revised capex is set out in table 7.11.

Table 7.11: Integral Energy's original and revised forecast capex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Original capex	573.9	641.5	610.4	582.5	544.3	2952.7
Revised capex	567.5	616.2	550.9	501.8	498.5	2734.9
Difference	–6.4	–25.3	–59.5	–80.7	–45.8	–217.8

Source: Integral Energy, *Revised regulatory proposal*, p. 35.
Note: Numbers may not add up due to rounding.

Integral Energy revised its forecast capex down by $244 million due to the global financial crisis.[393] Its revised regulatory proposal included:[394]

- a reduction of $173 million due to the deferral of major projects that had not been approved for construction by up to three years
- a reduction of $70 million due to revised customer connection forecasts following the receipt of revised NIEIR forecasts.

Integral Energy submitted its revised capex proposal in 2008–09 dollars. However, consistent with the draft decision,[395] it applied inflation of 3 per cent for the year to June

392 Integral Energy, *Revised regulatory proposal*, p. 35.
393 Integral Energy, *Revised regulatory proposal*, p. 29.
394 Integral Energy, *Revised regulatory proposal*, pp. 28–29.

2009 to inflate 2007–08 dollars to 2008–09 dollars. Integral Energy considered the final decision should be updated to include the December 2008 quarter CPI figures.[396]

Integral Energy implemented the draft decision in respect of forecast capex, except those related to:[397]

- the substation renewal projects
- real cost escalators
- the application of inflation.

Integral Energy's revised capex proposal of $2735 million ($2008–09) is approximately $218 million lower than its original capex proposal. Table 7.12 shows the annual profile of Integral Energy's revised capex proposal by category.[398]

Table 7.12: Integral Energy's revised capex proposal by category ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Growth	203.8	257.1	221.0	207.6	210.8	1100.4
Asset renewal/replacement	140.8	154.9	154.0	158.3	188.1	796.1
Reliability & quality of service enhancement	14.5	14.7	15.1	15.4	15.4	74.9
Compliance obligations	133.4	115.2	86.8	55.0	24.6	414.9
Other system	1.9	1.9	1.9	2.6	2.6	10.9
Total system	494.3	543.8	478.8	438.9	441.6	2397.3
Non–system assets	73.2	72.4	72.2	62.9	56.9	337.6
Total	567.5	616.2	550.9	501.8	498.5	2734.9

Source: Integral Energy, *Revised regulatory proposal*, p. 35.
Note: Totals may not add up due to rounding.

7.4 Submissions

The AER received submissions from:

- Country Energy
- EnergyAustralia (three submissions)
- Energy Markets Reform Forum (EMRF)
- Energy Users Association of Australia (EUAA)

395 For its draft decision the AER applied an inflation rate of 3 per cent in the roll forward model and noted that it would be updated at the time of its final decision.
396 Integral Energy, *Revised regulatory proposal*, p. 34.
397 Integral Energy, *Revised regulatory proposal*, p. 35.
398 Integral Energy, *Revised regulatory proposal*, p. 35.

- Public Interest Advocacy Centre Ltd (PIAC)
- Origin Energy.

The main issues raised in submissions related to:

- deliverability
- changing economic and business conditions, and the effects on energy forecasts, capex and cost escalators
- contingent projects
- binding determinations.

7.5 Issues and AER considerations

7.5.1 Deliverability of capex programs

In the draft decision, the AER noted the instability in world financial markets. The AER also noted that should the credit crisis persist, the NSW DNSPs may experience financial resource constraints going forward.[399, 400]

The EMRF, in its submission on the draft decision, noted the AER's concerns regarding deliverability and stated that, should a DNSP 'under run' its capex program due to deliverability concerns, consumers would pay for the capital not expended. It also stated it was incumbent on the AER to be assured that the capex requirements and the necessary roll over of current debt could be achieved.[401]

Origin Energy noted the change in economic conditions and the potential for this to impact capital raising and associated costs for the NSW DNSPs. It stated the change in economic conditions needed to be considered in terms of the NSW DNSPs forward capital investment program.[402]

On 27 January 2009, the AER sought clarification from the NSW DNSPs regarding any matters or circumstances that may affect their ability to obtain finance to deliver the capex programs they proposed for the next regulatory control period.[403]

The NSW DNSPs indicated they sought advice from the NSW Treasury Corporation on their ability to obtain finance[404] and that, to date, access to finance was not expected to constrain their ability to undertake capital works in the next regulatory control period.[405]

399 AER, *Draft decision*, pp. 150, 457, 498, 528.

400 The AER also notes comments raised by the EUAA in its submission on the NSW DNSPs draft decisions regarding the current economic climate and how this would affect the NSW DNSPs proposed capex programs.

401 EMRF, pp. 28–29.

402 Origin Energy, p. 5.

403 AER, Letters to the NSW DNSPs, 27 January 2009.

404 The information received from the NSW Treasury Corporation is confidential.

405 Country Energy, Letter to the AER, 18 February 2009; Integral Energy, Letter to the AER, 18 February 2009; and EnergyAustralia, Letter to the AER, 23 February 2009.

The NSW DNSPs concluded that they were satisfied with the conclusions reached in the draft decision.[406]

7.5.2 Growth and demand forecasts

The NSW DNSPs reconsidered their proposed capex programs in light of the anticipated impacts on global maximum demand of the worsening global financial crisis and the release of the Australian Government's CPRS white paper.[407,408]

In anticipating changes in global maximum demand and new customer connections over the next regulatory control period, the NSW DNSPs decreased their capex programs and proposed that a number of projects be deferred or reduced in scope:

- Country Energy revised down its forecast commercial and domestic subdivision growth capex by $58 million ($2008–09) during the next regulatory control period. It submitted that this was the result of new customer connection forecasts, which have fallen from 1.46 per cent to 1.29 per cent.[409]
- EnergyAustralia revised downward its proposed capex by $234 million. It proposed an $85 million reduction in its area plans due to the deferral, by up to 12 months, of projects due for completion after January 2012. It also proposed a $100 million reduction in its 11 kV development plans due to revised modelling that accounted for the revised forecasts, and a $46 million reduction in its low voltage capacity plan due to revised analysis on capital requirements by Evans & Peck.[410]
- Integral Energy revised downward its proposed capex by $244 million. It proposed a $173 million reduction due to the deferral, by between two and three years, in the timing and need for major projects to supply 'greenfield' land release areas and major commercial centres. It also proposed a $70 million reduction due to expected falls in new customer connections.[411]

The NSW DNSPs' revised demand forecasts are discussed in more detail in chapter 6 of this final decision.

Submissions

The EUAA stated the economic downturn would result in reduced demand for electricity and that this would affect the portion of capex aimed at meeting forecast network growth.[412]

The EUAA also stated that:[413]

406 AER, *Draft decision*, p. 150.
407 Australian Government, *Carbon pollution reduction scheme, Australia's low pollution future,* White paper, Volume 1, December 2008.
408 Country Energy and EnergyAustralia provided revised global maximum demand forecasts in their revised regulatory proposals. Integral Energy did not provide a revised maximum demand forecast, however it adjusted its proposed capex program in light of the worsening impact of the global financial crisis on maximum demand.
409 Country Energy, *Draft NSW distribution determination*, p. 3.
410 EnergyAustralia, *Revised regulatory proposal*, pp. 24–26.
411 Integral Energy, *Revised regulatory proposal*, pp. 28–29.
412 EUAA, p. 9.
413 EUAA, pp. 14–16.

- the AER should have gone further in its adjustments to the NSW DNSPs' capex proposals
- in a period of economic downturn, it was 'extraordinary' that the NSW DNSPs' revised regulatory proposals, with the exception of Integral Energy, proposed capex programs above the levels determined in the draft decision.

The EMRF stated that the expected reduction in electricity demand and consumption due to the economic downturn must be factored in to the AER's decisions regarding the NSW DNSPs' proposed capital programs.[414]

Origin Energy was similarly concerned with the change in economic conditions and indicated the AER needed to take further account of these issues when it assessed the NSW DNSPs capital programs and demand forecasts. It stated that if this did not occur, expenditure for the next regulatory control period would not be kept at efficient levels.[415]

AER considerations

The NSW DNSPs each provided updated capex proposals as a result of revised global maximum demand. The revised forecasts result from the change in the economic outlook for the Australian economy since mid-2008, as reflected in official forecasts by Treasury.[416] The rapid change in the economic outlook is closely linked to the global financial crisis which became apparent 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.[417] Given this extraordinary change in circumstances within the economic environment, the AER has decided to consider revisions to the NSW DNSPs' capex proposals arising from the global financial crisis in making its final decision. The AER has considered the concerns expressed by the EUAA, EMRF and Origin Energy regarding the need for the AER to take into account the changing economic and business environment when assessing the revised regulatory proposals.

The AER notes that while Country Energy and EnergyAustralia's revised regulatory proposals state that they have generated revised maximum demand forecasts, these revised forecasts were prepared at the top–down, global level, and do not incorporate spatial forecasts at the zone substation level.[418] Similarly, the revisions made to Integral Energy's capex proposal in light of the worsening global financial crisis were made on a top–down, global basis. Integral Energy's revisions were made without a revised maximum demand forecast. While global forecasts are useful as a check on spatial forecasts and to indicate general trends on the networks, spatial forecasts are required to assess necessary expenditure on the network. Accordingly, the AER's assessment of the revised capex programs due to revised global maximum demand forecasts is limited to an overall assessment of reasonableness.

414 EMRF, pp. 11–12.
415 Origin Energy, p. 3.
416 The Treasury, *Updated Economic and Fiscal Outlook*, February 2009.
417 IMF, *World Economic Outlook*, October 2008.
418 AER, phone call to Country Energy, 4 March 2009 and EnergyAustralia, *Response to stakeholder submissions*, p. 2.

As outlined in chapter 6 of this decision, the AER has decided to accept revised energy consumption forecasts for the next regulatory control period which are substantially lower than the energy forecasts considered in the draft decision. This is due to forecast slower economic growth and anticipated increases in retail electricity prices associated with higher network charges and the CPRS. By contrast, revisions made to Country Energy and EnergyAustralia's global maximum demand forecasts to account for these circumstances have resulted in small reductions in the rate of growth in demand. This is due to the differences in the relationship between economic growth, retail prices and maximum demand. However, the AER notes that the maximum demand forecasts were revised only on a top–down basis, and as such may not fully account for the changed environment since the draft decision. With this limitation noted the AER has assessed the reductions made to capex programs in accordance with revised maximum demand forecasts.

The AER considers the significant variance between the revised growth rates in energy and maximum demand to be an indication only of a short–run relationship and that over time price elasticity of maximum demand would be comparable with the price elasticity of energy, especially for non–residential customers. That noted the AER has analysed the specific changes made to the NSW DNSPs' global maximum demand forecasts to incorporate the changed environment and considers that the revised forecasts provide a reasonable expectation of overall global demand for the next regulatory control period. Further information on demand forecasts is provided in chapter 6 of this final decision.

In assessing the impact of the revised global maximum demand forecasts the AER has considered the relative magnitude of each NSW DNSPs' original proposed growth capex and adjustments made in their revised regulatory proposals. The AER notes that Country Energy,[419] EnergyAustralia[420] and Integral Energy[421] reduced their growth capex program by 4 per cent, 7 per cent and 18 per cent respectively over the next regulatory control period.

Country Energy's capex deferrals are related to its revised customer connection forecast, as summer maximum demand on its network, which is a key driver of capex, is forecast to remain largely unchanged despite slower economic growth. Accordingly, Country Energy's capex deferrals represent a smaller proportion of its growth capex than the other NSW DNSPs' deferrals. The AER's consideration of Country Energy's summer maximum demand forecast is provided in chapter 6.

In determining the impact of the global financial crisis on its network for the next regulatory control period, EnergyAustralia carried out a review of all projects in its area plans, identifying capacity driven projects with cash flows in the next regulatory control period which were due for completion after 1 January 2012.[422] EnergyAustralia also identified two of its larger capacity driven programs for which deferrals were possible and modelled the impact of the revised global maximum demand forecast on the need for expenditure. The reductions in capex tend to be from the middle of the next regulatory control period, which is not unexpected given the commitments in 2009–10 and 2010–11.

419 Country Energy, *Draft NSW distribution determination.*
420 EnergyAustralia, *Revised regulatory proposal*, p. 25.
421 Integral Energy, *Revised regulatory proposal*, p. 34.
422 EnergyAustralia, *Revised regulatory proposal*, attachment 13A, p. 8.

Integral Energy's deferred capex is largely the result of its revised customer connection forecast, and is related to the expected reductions in new land release development in its network region.[423] As Integral Energy's growth capex program is characterised by programs to cater for new developments, the AER considers it is reasonable to expect that its capacity for deferrals due to the global financial crisis is greater than both Country Energy and EnergyAustralia.

The AER notes that the NSW DNSPs' ability to defer or withdraw capex programs due to revised maximum demand is limited by several factors. A number of growth capex projects planned for the beginning of the next regulatory control period have been deferred in the current regulatory control period due to resource constraints, and are insensitive to short–term changes in maximum demand. The timing of capex also limits the ability of the NSW DNSPs to defer capex programs. This is particularly the case where contracts have already been established for work within the first few years of the next regulatory control period. Any significant deferrals would be expected to occur from the middle of the next regulatory control period, for projects that are currently being planned, and the need for which is still being assessed.

The AER also considers that there is not a linear relationship between short–term changes in maximum demand and planned growth capex. This limits the ability to carry out a top–down comparative assessment of the changes to the DNSPs' capex programs. Additionally, as the NSW DNSPs did not prepare revised spatial maximum demand forecasts, the AER is unable to consider further specific capex deferrals or reductions. That said, the AER considers that the DNSPs have appropriately assessed their capacity to defer capex at the global level.

The AER considers that spatial information would have been beneficial but recognises that analysis of this type would take several months to undertake. On balance, the AER considers that the global approach has permitted the NSW DNSPs to revise their capex proposals to reflect the impact of the worsening global financial crisis on global maximum demand. It is on this basis that the AER considers that the revisions to the NSW DNSPs' capex proposals are reasonable.

7.5.3 Cost escalators

The NSW DNSPs did not accept the materials cost escalators applied by the AER in the draft decision. They engaged Competition Economists Group (CEG) to review the draft decision and, based on that advice, determined that while the AER's approach was largely reasonable, they had concerns with:[424]

- technical aspects of the modelling
- the proposed approach to updating labour cost escalation factors.

The NSW DNSPs accepted the AER determined cost escalator for land. However, revisions were proposed for the majority of the other escalators. The NSW DNSPs were particularly concerned with the AER's approach to:

- labour escalation

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423 Integral Energy, *Revised regulatory proposal*, p. 28.

424 CEG, *Escalations affecting expenditure forecasts, A report for NSW and Tasmanian Electricity Businesses*, January 2009, p. 2.

- indirect producer’s labour (Country Energy and EnergyAustralia)
- timing
- lags.

Further details on these issues are provided in appendix L of this final decision.

AER considerations

The AER’s detailed considerations and decision on each escalator and associated forecasting method arising out of CEG’s recommendations are contained in appendix L of this final decision.

In response to the issues raised in the draft decision, the AER re–engaged Econtech to provide independent forecasts of wages growth in NSW. The AER once again notes that the labour component of expenditures is large, particularly for opex. In all other cases, the AER has assessed the validity of the proposed escalators with respect to data from published sources, and has closely examined how each escalator contributed to the proposed expenditures.

The AER does not agree with EnergyAustralia’s proposed lag between commodity price increases (and labour costs), and the costs it faces in the purchase of equipment and the delivery of its investment programs. The AER notes that there was a paucity of robust evidence supporting the application of a lag of six months. Consequently, the AER does not consider that the application of a lag to commodity price changes is appropriate and has applied this decision to all NSW DNSPs seeking to have lags included as part of their regulatory determinations for the next regulatory control period.

The AER also considers that EnergyAustralia’s proposed escalator for wood poles is not adequately justified. The AER does not consider it appropriate to assume that wood pole prices will continue to increase at the historical rate over the next regulatory control period without evidence to support that assumption. Moreover, it is high by comparison to those escalators proposed by other DNSPs for what the AER considers to be a fairly generic asset type. For these reasons the AER does not accept EnergyAustralia’s pole escalator.

The AER considers EnergyAustralia’s proposed escalators for components of non– system capex, namely land, buildings and general IT labour, to be reasonable.

With respect to material cost escalators proposed by Integral Energy and Country Energy as part of their forecast capex allowance, the AER has made adjustments to the method used to forecast copper, steel and aluminium as proposed by CEG, and used updated data with respect to forecast construction costs, crude oil and exchange rates which are used in the conversion of costs into Australian dollar terms.

With respect to Country Energy and EnergyAustralia, the AER has also removed the effect of indirect labour cost escalation on its capex program.

AER conclusion

Tables 7.13, 7.14 and 7.15 set out the AER’s conclusions on the NSW DNSPs’ real escalators over the next regulatory control period. More detailed information on the AER’s final assessment is detailed in appendix L of this final decision.

Table 7.13: AER conclusion on Country Energy's real escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–16.13	–17.34	–14.06	9.13	10.55	10.93	9.32
Copper	–6.93	–27.93	–10.83	2.06	2.46	2.32	1.96
Steel	5.57	16.27	–15.32	7.21	5.25	1.03	0.76
Crude oil	28.58	–18.33	–5.19	10.24	5.74	2.16	1.30
EGW wages	–0.17	–0.38	2.54	3.60	2.40	1.70	0.60
General wages	0.90	–1.60	0.70	1.30	0.40	0.10	–0.60
Construction costs	2.75	–1.28	–1.64	1.00	0.65	–0.37	–2.22

Table 7.14: AER conclusion on EnergyAustralia's real escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–19.83	–17.34	–14.06	9.13	10.55	10.93	9.32
Copper	–1.31	–27.93	–10.83	2.06	2.46	2.32	1.96
Steel	12.40	16.27	–15.32	7.21	5.25	1.03	0.76
Crude oil	31.54	–18.33	–5.19	10.24	5.74	2.16	1.30
EGW wages	1.46	0.20	3.35	3.60	2.40	1.70	0.60
General wages	1.01	–1.60	0.70	1.30	0.40	0.10	–0.60
Construction costs	3.17	–1.28	–1.64	1.00	0.65	–0.37	–2.22

Table 7.15: AER conclusion on Integral Energy's real escalators (per cent)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–10.19	–14.06	9.13	10.55	10.93	9.32
Copper	–17.35	–10.83	2.06	2.46	2.32	1.96
Steel	36.24	–15.32	7.21	5.25	1.03	0.76
Crude oil	–16.73	–5.19	10.24	5.74	2.16	1.30
EGW wages	1.38	3.35	3.60	2.40	1.70	0.60
General wages	–1.80	0.70	1.30	0.40	0.10	–0.60
Construction costs	–0.91	–1.64	1.00	0.65	–0.37	–2.22

7.5.4 Country Energy

7.5.4.1 Non–system IT capex

AER draft decision

In the draft decision, the AER rejected Country Energy's proposed non–system IT capex allowance of $263 million. The AER was not satisfied that this expenditure reflected the efficient costs that a prudent operator, in the circumstances of Country Energy, would require to satisfy the capex objectives. It considered that, when benchmarked in comparable terms against other DNSPs, Country Energy's proposed IT expenditure appeared inefficiently high, and had not been sufficiently justified in financial terms.[425]

The AER reduced Country Energy's non–system IT expenditure forecast by 25 per cent ($66 million) to bring it to a level comparable with other DNSPs.[426] The AER considered that this reduction resulted in costs which reasonably reflected those that a prudent operator, in the circumstances of Country Energy, would require to achieve the capex objectives in accordance with the capex criteria.

Revised regulatory proposal

Country Energy did not accept the AER's reduction to the non–system IT capex forecast and submitted a revised forecast of $256 million.[427] It stated that this level of investment was appropriate for a regionally based business, given the current position in its IT investment cycle.[428]

Country Energy raised a number of methodological concerns with Wilson Cook's benchmarking analysis and the use of the results to assess the efficiency of its proposed

[425] AER, *Draft decision*, p. 454.
[426] AER, *Draft decision*, p. 454.
[427] This revised amount excluded approximately $7 million for 'un-scoped' IT projects.
[428] Country Energy, *Revised regulatory proposal*, p. 37.

capex. It noted that its IT expenditure program underpinned the overall efficiency and prudence of its forecast capex program.[429]

Country Energy stated that its IT systems life cycle had converged to a point where major business systems required replacement within the next few years, and that if this capex was not approved it would face:[430]

- increased business inefficiency due to the lack of integration between systems, data and processes
- increased opex costs to maintain and support systems which have reached 'end of life'
- an increased risk that its major systems would become unsupported, as the small vendors that support its products exit the market.

Consultant review

Wilson Cook noted the information provided in support of Country Energy's revised regulatory proposal permitted a more detailed assessment of non–system IT capex, including a 'bottom up' assessment.[431]

Wilson Cook noted the concerns raised regarding its reliance on benchmarking and indicated that it has limited the use of this analysis to a test of reasonableness of its new bottom up analysis.[432] It also noted that after removing the proposed optical fibre investment[433] from the benchmarked IT allowance (which was included in its initial analysis), Country Energy's non–system IT capex still appeared higher than the industry norm.[434]

Wilson Cook concluded that the benchmarking it undertook supported its bottom up analysis and that a reduction to Country Energy's capex was appropriate. It made the following observations on Country Energy's revised non–system IT capex proposal:[435]

- enhancement and improvement expenditures may be overstated by around $27 million
- estimates for the asset management system included a $4.6 million allowance for contract management, which should have been expensed.

Based on its bottom up analysis, Wilson Cook recommended Country Energy's forecast non–system IT capex allowance be reduced by $27 million for the enhancement expenditures and $4.6 million for contract management (an opex item).[436]

AER considerations

The AER notes that Country Energy's $57 million cost estimate to replace its asset management system (AMS) includes $2.4 million over three years for new AMS

429 Country Energy, *Revised regulatory proposal*, p. 37.
430 Country Energy, *Revised regulatory proposal*, p. 43.
431 Wilson Cook, *Review of proposed expenditure of ACT and NSW electricity DNSPs: Country Energy's submissions of January and February 2009*, March 2009, p. 4.
432 Wilson Cook, *Country Energy review*, p .6.
433 Wilson Cook noted that this expenditure could be classified as system expenditure and therefore removed it from the non–system IT benchmarking analysis.
434 Wilson Cook, *Country Energy review,* p. 6.
435 Wilson Cook, *Country Energy review*, pp. 3–7.
436 Wilson Cook, *Country Energy review*, p. 5.

‘customisation’ work.[437] In addition, Country Energy has proposed to spend a further $21 million in the next regulatory control period to maintain and enhance its existing AMS and review and enhance its new AMS, following its implementation.[438]

Country Energy has also proposed to replace its customer information system (CIS) at an estimated cost of $33 million, which includes an annual allowance of $1.7 million to review, enhance and implement the core customer information modules.[439] In addition to this allowance, Country Energy’s IT capital works plan includes $21 million over the next regulatory control period for a supplementary program of enhancement and modification of the CIS.[440] Country Energy has also included a total forecast allowance of $16 million for the enhancement and modification of ‘other’ system modules commencing in 2010–11.[441]

The AER notes Wilson Cook’s view that enhancement expenditure for existing systems would be expected to decrease given the planned increase in investment in new IT systems. The AER accepts that modification and adjustment of the new systems is likely to be necessary following implementation. However, given the replacement AMS and CIS are planned for deployment in the near future (from 2010–12), it considers that there should be minimal requirement for further prudent expenditure on the existing systems, other than for non–discretionary maintenance.

Based on its analysis of Country Energy’s revised regulatory proposal and advice from Wilson Cook, the AER considers that Country Energy’s non–system IT forecasts are likely to be overstated for the following reasons:

- some enhancement and customisation costs for the AMS and CIS modules are implicit in the overall project cost estimates
- it is not clear that the work proposed under the additional enhancement programs is distinct from that included in the broader AMS and CIS project estimates
- increased expenditure (other than non-discretionary maintenance) on existing AMS and CIS identified for imminent decommissioning is unlikely to be prudent and has not been sufficiently justified.

Given these concerns, the AER has reduced the annual forecast costs for the discrete CIS, AMS and ‘other’ module enhancement to Country Energy’s 2009–10 forecast levels for the next regulatory control period.

After applying the network cost allocation factor to the shared projects,[442] and converting to real dollars, the AER has reduced Country Energy’s forecast allowance by $27 million ($2008–09) to account for this overstatement.

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437 Country Energy, *Revised regulatory proposal*, attachment 5.1.1, p. 54.

438 Country Energy, *Revised regulatory proposal,* appendix F: Information technology works program 2009–14, p. 26.

439 Country Energy, *IT works program, 2009–14*, p. 20.

440 Country Energy, *IT works program, 2009–14*, pp. 30–32.

441 Country Energy, *IT works program, 2009–14*, pp. 41–43

442 Country Energy allocates 78.4 per cent of shared costs to its network business in accordance with its approved cost allocation method.

The AER also notes the inclusion of an apparent opex line item in the cost estimates to replace the existing AMS. This item attributes \$4.6 million (\$2008–09) in the final year of the period to a 'maintenance and support contract'.[443] The AER considers this item should not be capitalised as it does not represent a cost of bringing the new AMS into service.

In summary, the AER has made the following adjustments to Country Energy's revised forecast non–system IT capex allowance:

- removed \$27 million (\$2008–09) in allowances for additional enhancement and customisation of AMS and CIS implicit in the high level project forecasts
- removed an opex line item estimated at \$4.6 million (\$2008–09).

For the reasons discussed above and as a result of the AER's analysis of the revised regulatory proposal, the AER is not satisfied that the proposed non–system IT expenditure of \$256 million reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

7.5.4.2 Non–system land and buildings expenditure

AER draft decision

In the draft decision, the AER was not satisfied that the non–system land and buildings expenditure forecasts reflected the efficient costs that a prudent operator, in the circumstances of Country Energy, would require to satisfy the capex objectives. The AER reviewed Country Energy's property capital works schedule and its total expenditure forecasts, and identified potential double counting in its forecasts of building and accommodation requirements.[444]

The AER considered that some of Country Energy's additional accommodation needs were implicit in the detailed capital works schedule and should not be added to the base estimate forecasts. To correct for this apparent double counting, the AER reduced Country Energy's expenditure category by 50 per cent, or \$21 million.[445]

Revised regulatory proposal

Country Energy did not accept the AER's \$21 million reduction. It submitted that it had revisited the non–system land and building capex estimates and found that, while there was some overlap between the 'business as usual' program and additional resource requirements, the impact was not to the extent of the AER's \$21 million reduction.[446]

Country Energy submitted that approximately 27.4 per cent of the total additional non–system land and buildings resources it required over the next regulatory control period had been inadvertently included in the 'business as usual' non–system land and

[443] Country Energy, *Revised regulatory proposal*, attachment 5.1.1, p. 54.
[444] AER, *Draft decision*, p. 454.
[445] AER, *Draft decision*, p. 455.
[446] Country Energy, *Revised regulatory proposal*, p. 44.

buildings capex program.[447] It submitted a revised regulatory proposal that included a reduction of $11 million to correct for the identified double counting.[448]

Consultant review

Wilson Cook reviewed Country Energy's revised regulatory proposal and additional analysis, and concluded that the extent of the double counting had been satisfactorily investigated by Country Energy. It recommended that Country Energy's revised estimate of 27.4 per cent should be accepted in place of the 50 per cent reduction originally recommended.[449]

AER considerations

The AER has reviewed Country Energy's revised regulatory proposal and additional supporting information and is satisfied that the extent of the double counting is 27.4 per cent of the total forecast additional resources required by Country Energy over the next regulatory control period. This indicates that Country Energy's original forecast land and buildings capex was overstated by approximately $11 million ($2008–09). The AER has reviewed Country Energy's revised capex model and has confirmed that this amount has been removed from the revised non–system forecast capex allowance.

7.5.4.3 Tap position and relay settings capex

AER draft decision

The AER's draft decision removed $12 million from Country Energy's capex allowance associated with the adjustment of voltage regulation relay settings and distribution transformer tap positions.[450] The AER considered these works are typically expensed and should not be included in the capex allowance.

AER considerations

The AER reviewed Country Energy's revised capex and opex models and identified that, while this expenditure item had been added to the opex allowance, it had not been removed from the capex allowance. Country Energy subsequently advised the AER that this item had been inadvertently retained in its revised capex allowance and confirmed that this item should be removed from the 'reliability and quality of service enhancement' capex category.[451]

The AER has removed $12 million from Country Energy's revised capex forecast to correct for this error.

447 Country Energy, *Revised regulatory proposal*, p. 44.
448 Country Energy, *Revised regulatory proposal*, p. 44.
449 Wilson Cook, *Country Energy review*, p. 7.
450 AER, *Draft decision*, pp. 447, 458.
451 Country Energy, Email to AER, 20 February 2009.

7.5.5 EnergyAustralia

7.5.5.1 'Black spot' network reliability program

AER draft decision

In the draft decision, the AER was not satisfied that EnergyAustralia had demonstrated that the 'black spot' reliability program was required to maintain the quality, reliability, safety and security of standard control services and the distribution system. The AER also noted that the objective of the 'black spot' reliability program was not to comply with an applicable regulatory obligation or requirement, nor to meet or manage expected demand.[452]

The AER was not satisfied that the objectives of EnergyAustralia's 'black spot' reliability program were consistent with the capex objectives. The AER therefore reduced EnergyAustralia's capex by $16 million ($2008–09) to reflect the costs which a prudent operator, in the circumstances of EnergyAustralia, would require to achieve the capex objectives in accordance with the capex criteria.[453]

Revised regulatory proposal

EnergyAustralia did not accept the AER's finding that the proposed 'black spot' reliability program was not consistent with the capex objectives. It stated the 'black spot' reliability program was consistent with the capex objectives at a customer level and should be reinstated.[454]

EnergyAustralia also stated the 'black spot' reliability program was a reactive program that sought to improve network performance when it fell below a 'black spot' threshold level and thus maintain the performance of the network.[455]

Consultant review

Wilson Cook noted that the 'black spot' reliability program appeared to entail an interpretation of the NER.[456]

AER considerations

The AER notes EnergyAustralia's position that the 'black spot' reliability program addresses deterioration in the reliability of the network by bringing it back to an appropriate level. It further notes that EnergyAustralia stated that such an approach is consistent with 'maintaining' the reliability of supply of standard control services.[457]

The AER also notes that EnergyAustralia stated that:

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452 AER, *Draft decision*, pp. 493–494.
453 AER, *Draft decision*, pp. 493–494.
454 EnergyAustralia, *Revised regulatory proposal*, p. 37.
455 EnergyAustralia, *Revised regulatory proposal*, pp. 38–39.
456 Wilson Cook, *Review of proposed expenditure of ACT and NSW electricity DNSPs: EnergyAustralia's submissions of January and February 2009*, March 2009, pp. 3–4.
457 EnergyAustralia, *Revised regulatory proposal*, pp. 37–39.

> The expected outcomes of the program are to maintain the reliability of the network and reliability of standard control services above the blackspot threshold, by improving network performance when it falls below the threshold level.[458]

The AER considers that such an approach could be consistent with the capex objectives depending on how the 'black spot' threshold is determined. The AER notes that EnergyAustralia, in setting the 'black spot' threshold, chose:

> Pragmatic thresholds … such that the number of customers worse than these thresholds is limited to around 2% of the customer category base.[459]

Furthermore, the AER notes that EnergyAustralia's proposed 'black spot' thresholds:

> … are more onerous than the previous EnergyAustralia Way Ahead targets (2003/04 and 2004/05). The Way Ahead targets were chosen to limit the number of customers that exceed those targets to approx less than 1% of the customer base.[460]

The AER considers that by increasing its threshold for undertaking individual customer reliability capital works, EnergyAustralia is increasing, rather than maintaining, the reliability of standard control services and the distribution system. The AER notes that EnergyAustralia's licence conditions do not require it to improve reliability at the individual customer level. Consequently, the AER considers that the proposed 'black spot' reliability program is not consistent with the capex objectives.

The AER also notes that it is not its role to decide whether EnergyAustralia should undertake the 'black spot' program or any other proposed capex program. Under the transitional chapter 6 rules, the AER must accept, or not accept, the forecast capex of a DNSP if it is satisfied that the total forecast capex reasonably reflects, among other considerations, the efficient costs a prudent operator would require to achieve the capex objectives.

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

7.5.5.2 Zone substation expenditure

AER draft decision

In the draft decision, the AER was not satisfied that the non–civil zone substation capex proposed by EnergyAustralia reasonably reflected the efficient costs that a prudent operator, in the circumstances of EnergyAustralia, would require to achieve the capex objectives.[461] The AER gave particular attention to a review conducted by Sinclair Knight Merz Pty Ltd (SKM) of EnergyAustralia's zone substation cost estimates, which EnergyAustralia included in its regulatory proposal.

458 EnergyAustralia, *Revised regulatory proposal*, p. 38.
459 EnergyAustralia, '*Black spot' reliability program individual customer reliability thresholds: version 1.0*, May 2008, p. 5.
460 EnergyAustralia, '*Black spot': version 1.0,* May 2008, p. 6.
461 AER, *Draft decision*, p. 469.

The AER compared SKM and EnergyAustralia's zone substation cost estimates and concluded that EnergyAustralia's estimates for 33 kV substation projects with air insulated switchgear and 132 kV substation projects with gas insulated switchgear were systematically higher than SKM's estimates. The AER noted that, on average, SKM's cost estimates were 6 per cent lower than EnergyAustralia's.[462]

The AER recognised that there is a degree of uncertainty regarding the efficient level of substation costs and concluded that the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require would be the value midway between EnergyAustralia's and SKM's estimates. Consequently, the non-civil substation capex estimate that the AER was satisfied reasonably reflected the efficient costs that a prudent operator, in the circumstances of EnergyAustralia, would require was 3 per cent (or $34 million, $2008–09) less than that proposed by EnergyAustralia.[463]

Revised regulatory proposal

EnergyAustralia did not accept the AER's conclusions regarding its zone substation cost estimates. EnergyAustralia stated there is a range of reasons for the difference between its cost estimates and SKM's, including: [464]

- the cost of work in congested metropolitan areas
- the difference in wage rates between Sydney and other areas considered in SKM's benchmark costs
- variation between costs of equipment arising from specific purchasing arrangements and timing (for example, exchange rate and contract timing differences)
- variations in equipment type or performance.

EnergyAustralia also stated that the sample of projects reviewed by SKM was not a representative sample of the work it would undertake during the next regulatory control period. It indicated that if SKM's results were weighted to reflect the proposed work program, the difference between its estimates and SKM's cost estimates would fall from 6 per cent to 3 per cent.[465]

EnergyAustralia also stated that the AER's consideration of its zone substation costs did not appropriately regard the views of the independent consultants Wilson Cook and PB.[466] Furthermore, it considered that the AER's approach to EnergyAustralia's proposal was not consistent with the approach used for Country Energy and Integral Energy. In particular, it considered that the AER found the capex proposed by those businesses to be efficient on the basis of information other than cost benchmarking.[467]

AER considerations

The AER notes that EnergyAustralia provided additional information on the costs associated with its zone substations. In particular, the AER notes that SKM identified an error in its original analysis—its cost estimates for gas insulated switchgear equipped

462 AER, *Draft decision*, p. 468.
463 AER, *Draft decision*, p. 470.
464 EnergyAustralia, *Revised regulatory proposal*, pp. 40–41.
465 EnergyAustralia, *Revised regulatory proposal*, p. 41.
466 EnergyAustralia, *Revised regulatory proposal*, p. 41.
467 EnergyAustralia, *Revised regulatory proposal*, pp. 41–42.

substations did not use low noise transformers which are required to meet planning requirements.[468] The AER also recognises SKM's concerns that the AER's analysis assumed that the sample of projects was representative of EnergyAustralia's capex proposal.

The AER agrees with SKM's advice and EnergyAustralia's revised regulatory proposal that any analysis of substation cost estimates should be weighted to account for the particular substations proposed in the next regulatory control period. The AER notes that by adopting this approach, and correcting the error identified, the difference in cost estimates between SKM and EnergyAustralia falls to 3.2 per cent.[469]

The AER also notes that in its revised regulatory proposal, EnergyAustralia stated reasons as to why its estimates may differ from SKM's include:

- allowing for costs of work in congested metropolitan areas
- differences in wage rates between Sydney and other areas considered in SKM's benchmark costs
- variation between costs of equipment arising from specific purchasing arrangements and timing (i.e. influenced by exchange rates, timing of contracts, and existing supply arrangements)
- variations in equipment type or performance (i.e. equipment rating fault duty, transformer noise performance).[470]

The AER considers that the first two of these reasons in particular, are valid reasons for explaining the difference between EnergyAustralia's and SKM's zone substation cost estimates and have been taken into account in determining EnergyAustralia's capex allowance. Consequently, the AER considers that the inefficiency identified by way of a benchmark assessment in the draft decision has been explained by a closer examination of projects used in the benchmark sample.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal, the AER is satisfied that EnergyAustralia's capex proposal for zone substation expenditure reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER has had regard to the capex factors.

7.5.5.3 Tariff based demand management

AER draft decision

In the draft decision, the AER accepted EnergyAustralia's regulatory proposal regarding the downward impact of tariff based demand management on its capex proposal.

Revised regulatory proposal

In its revised regulatory proposal, EnergyAustralia revised its forecast capex upward by $31 million to remove the impact of tariff based demand management. It considered that the draft decision on re–assigning customers to other tariff classes would restrict the

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468 SKM, *Considerations on AER review of EnergyAustralia's substation cost estimation process*, 7 January 2009, pp. 3–4.

469 SKM, *EnergyAustralia's substation cost estimation process*, p. 6.

470 EnergyAustralia, *Revised regulatory proposal*, pp. 40–41.

application of tariff based demand management in the next regulatory control period, and limit the scope for its capex to be reduced.[471]

AER considerations

The AER's consideration of customer re–assignment is outlined in chapter 2. The AER does not consider that its decision on assigning customers to tariff classes will restrict EnergyAustralia from undertaking tariff based demand management in the next regulatory control period.

As discussed in chapter 2, the AER considers that its revised procedures for assigning and re–assigning customers to tariff classes does not restrict the circumstances in which a re–assignment can take place. Consequently, the AER is not satisfied that EnergyAustralia's capex proposal reasonably reflects the capex criteria. Accordingly, the AER has adjusted EnergyAustralia's revised capex proposal by $28 million. In coming to this view the AER has had regard to the capex factors.

7.5.6 Integral Energy

7.5.6.1 Substation renewal projects

AER draft decision

In the draft decision, the AER was not satisfied that sufficient documentation had been provided to substantiate claims for renewal expenditure which deviated from historical trends.[472]

The AER revised Integral Energy's renewal capex downward by $29 million to reflect the costs that a prudent operator in the circumstances of Integral Energy would require to achieve the capex objectives in accordance with the capex criteria.[473]

Revised regulatory proposal

Integral Energy did not accept the AER's reduced allowance for its renewal capex and proposed a revised cost estimate of $796 million for substation renewal projects.[474]

Integral Energy stated that its substation renewal projects required additional investment due to condition assessments, as identified in its strategic asset renewal plan.

Integral Energy considered that Wilson Cook's final report had not fully considered the information it had supplied, given Wilson Cook's final recommendation included a $15 million reduction on its substation renewal projects. It stated that a reduction of this size would impact nine of its 14 proposed renewal projects.[475]

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471 EnergyAustralia, *Revised regulatory proposal*, pp. 27–28.
472 AER, *Draft decision*, p. 520.
473 AER, *Draft decision*, p. 520.
474 Integral Energy, *Revised regulatory proposal*, pp. 30–31.
475 Integral Energy, *Revised regulatory proposal*, p. 30.

Consultant review

Wilson Cook reconsidered its proposed adjustment to Integral Energy's substation renewal capex and maintained that it was satisfied that the documentation provided by Integral Energy in its original proposal had been adequately considered.[476]

Wilson Cook noted that it had sought further information from Integral Energy on the scope of work involved in these projects, due to its concerns with capex deviating from expenditure trends, particularly in the final year of the next regulatory control period. Integral Energy advised Wilson Cook that it expected an increased level of work in this area, as more substations would become candidates for renewal. Wilson Cook acknowledged that renewal expenditure may increase over time but noted expenditure trends remained relatively flat up to and including the 2013 financial year.[477]

Wilson Cook considered that Integral Energy had not provided sufficient documentation to support deviating from trend expenditure. Further, Wilson Cook considered expenditure based on established levels of work should take precedence over increased expenditure that lacked robust supporting documentation. Wilson Cook therefore, did not consider it reasonable to accept Integral Energy's sharp upward turn in proposed expenditure at the end of next regulatory control period and recommended a downward adjustment of $15 million to Integral Energy's substation renewal capex. Wilson Cook concluded that this adjustment exhibited a rising trend consistent with Integral Energy's replacement needs.[478]

In correspondence to the AER, Wilson Cook reaffirmed that its consideration of Integral Energy's revised regulatory proposal and its proposed adjustment on substation renewal expenditure, as set out in its final report, remained unchanged.[479]

AER considerations

Based on the information provided by Integral Energy, Wilson Cook and its own analysis, the AER considers that the expenditure associated with the substation renewal projects does not result in forecast expenditure that reflects the efficient costs a prudent operator, in the circumstances of Integral Energy, would require to achieve the capex objectives, in accordance with the capex criteria.

As the AER is not satisfied that the information included in Integral Energy's revised regulatory proposal is sufficient to support a level of expenditure that deviates from actual replacement related capex expensed it maintains its downward adjustment of $15 million to Integral Energy's capex. The AER considers that this level of expenditure better aligns with expenditure trends and reasonably satisfies the capex criteria.

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

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476 Wilson Cook, *Review of proposed expenditure of ACT and NSW electricity DNSPs: Integral Energy's submissions of January and February 2009*, 31 March 2009, p. 3.

477 Wilson Cook, *Review of proposed expenditure of ACT and NSW electricity DNSPs, Volume 3 – Integral Energy*, October 2008, pp. 21, 27 and Wilson Cook, *Integral Energy review*, p. 2.

478 Wilson Cook, *Volume 3*, p. 21; and Wilson Cook, *Integral Energy review*, pp. 2–3.

479 Wilson Cook, *Integral Energy review*, p. 3.

7.6 AER conclusion

For the reasons summarised in this chapter the AER is not satisfied that the proposed forecast capex allowances of each NSW DNSP reasonably reflect the capex criteria, under clause 6.5.7(c) of the transitional chapter 6 rules. In reaching this conclusion, the AER has had regard to the capex factors set out in clause 6.5.7(e) of the transitional chapter 6 rules, including:

- the information included in or accompanying the revised regulatory proposals
- submissions received in the course of consulting on the revised regulatory proposal
- analysis undertaken by or for the AER and published as part of the final decision of the AER.

These are important considerations in determining whether the AER is satisfied that each NSW DNSP's forecast capex proposal reasonably reflects the capex criteria, which are themselves couched in terms of achieving the capex objectives.

As the AER is not satisfied that the capex allowances proposed by the NSW DNSPs reasonably reflects the capex criteria, under clause 6.5.7(d) of the transitional chapter 6 rules the AER must not accept them in its distribution determination. Under clause 6.12.1(3)(ii) of the transitional chapter 6 rules, the AER is therefore required to provide an estimate of the capex for each NSW DNSP over the next regulatory control period which it is satisfied reasonably reflects the capex criteria, including the capex objectives. In coming to this view the AER must have regard to the capex factors.

The AER is satisfied that its conclusions on the forecast capex allowances for the next regulatory control period for each NSW DNSP reasonably reflect the capex criteria. These capex allowances are summarised below.

7.6.1 Country Energy

Following its review of Country Energy's revised capex proposal the AER has made the following adjustments:

- $12 million reduction for incorrectly capitalised tap changer and relay setting works, consistent with the draft decision
- $32 million reduction to non–system IT expenditure
- $119 million reduction to reflect the application of modified input cost escalators to its capex program as determined in appendix L.

Following the adjustments outlined above, and as detailed in table 7.16, the AER is satisfied an estimate of $3826 million for Country Energy's forecast capex reasonably reflects the efficient costs a prudent operator in the circumstances of Country Energy would require to achieve the capex objectives. In reaching this conclusion, the AER has had regard to whether the forecast capex proposal reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

Table 7.16: AER conclusion on Country Energy's capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER draft decision	742.6	776.8	799.9	809.3	826.7	3955.4
Country Energy proposed capex	743.4	792.6	813.7	811.0	828.7	3989.3
Adjustment for IT expenditure	–3.0	–6.0	–6.0	–6.1	–10.7	–31.8
Adjustment for relay setting and tap changers	–2.4	–2.4	–2.4	–2.4	–2.5	–12.1
Adjustment for cost escalators	–22.4	–26.7	–28.8	–23.3	–18.3	–119.5
AER capex allowance	715.7	757.5	776.5	779.1	797.2	3826.0

Note: Totals may not add up due to rounding.

7.6.2 EnergyAustralia

Following its review of EnergyAustralia's revised capex proposal the AER has made the following adjustments:

- $15 million reduction to the 'black spot' reliability program
- $28 million reduction for tariff based demand management
- $421 million reduction to reflect the application of modified input cost escalators to its capex program as determined in appendix L.

Following the adjustments outlined above, and as detailed in tables 7.17 and 7.18, the AER is satisfied an estimate of $7838 million for EnergyAustralia's forecast capex reasonably reflects the efficient costs a prudent operator in the circumstances of EnergyAustralia would require to achieve the capex objectives. In reaching this conclusion, the AER has had regard to whether the forecast capex proposal reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

Table 7.17: AER conclusion on EnergyAustralia's distribution capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER draft decision	1300.0	1401.8	1563.1	1433.4	1459.6	7157.9
EnergyAustralia proposed capex	1292.7	1398.4	1501.8	1420.2	1437.3	7050.4
Adjustment to 'black spot' reliability project	–3.0	–3.1	–3.1	–3.1	–3.1	–15.4
Adjustment for tariff based demand management	–	–	–	–	–25.4	–25.4
Adjustment for cost escalators	–157.5	–113.7	–76.5	–40.2	14.5	–373.3
Adjustment for transmission/distribution allocation (non–system)	0.5	0.3	0.2	0.2	0.2	1.4
AER capex allowance	1132.7	1281.9	1422.5	1377.1	1423.5	6637.7

Note: Totals may not add up due to rounding.

Table 7.18: AER conclusion on EnergyAustralia's transmission capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER draft decision	264.0	178.9	264.9	339.7	229.3	1276.8
Total EnergyAustralia proposed capex	271.9	180.4	256.6	336.0	207.7	1252.6
Adjustment for tariff based demand management	–	–	–	–	–2.5	–2.5
Adjustment for cost escalators	–7.7	–6.0	–11.1	–15.4	–8.0	–48.1
Adjustment for transmission/distribution allocation (non–system)	–0.5	–0.3	–0.2	–0.2	–0.2	–1.4
AER capex allowance	263.7	174.2	245.3	320.4	197.0	1200.5

Note: Totals may not add up due to rounding.

7.6.3 Integral Energy

Following its review of Integral Energy's revised capex proposal the AER has made the following adjustments:

- $15 million reduction to substation renewal projects
- $2.0 million increase to reflect the application of modified input cost escalators to its capex program as determined in appendix L.

Following the adjustments outlined above, and as detailed in table 7.19, the AER is satisfied an estimate of $2721 million for Integral Energy's forecast capex reasonably reflects the efficient costs a prudent operator in the circumstances of Integral Energy would require to achieve the capex objectives. In reaching this conclusion, the AER has had regard to whether the forecast capex proposal reasonably reflects the capex criteria, including the capex objectives. In coming to this view, the AER has had regard to the capex factors.

Table 7.19: AER conclusion on Integral Energy's capex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER draft decision	571.9	638.0	606.3	575.5	521.9	2913.7
Integral Energy proposed capex	567.5	616.2	550.9	501.8	498.5	2734.9
Adjustments arising from replacement capex	0.0	0.0	0.0	0.0	–15.4	–15.4
Adjustment for cost escalators	3.2	2.5	–0.1	–0.9	–2.8	2.0
AER capex allowance	570.7	618.7	550.9	500.9	480.3	2721.4

Note: Totals may not add up due to rounding.

7.7 AER decision

In accordance with clause 6.12.1(3)(ii) of the transitional chapter 6 rules the AER does not accept Country Energy's forecast capex for the next regulatory control period. The AER's reasons for this decision are set out in section 7.8 of the draft decision and 7.5 of this final decision.

The AER's estimate of the total capex required by Country Energy in the next regulatory control period, that reflects the capex criteria taking into account the capex factors, is set out in table 7.16 of this final decision.

In accordance with clause 6.12.1(3)(ii) of the transitional chapter 6 rules the AER does not accept EnergyAustralia's forecast capex for the next regulatory control period. The AER's reasons for this decision are set out in section 7.8 of the draft decision and 7.5 of this final decision.

The AER's estimate of the total distribution and transmission capex required by EnergyAustralia in the next regulatory control period, that reflects the capex criteria taking into account the capex factors, is set out in tables 7.17 and 7.18 respectively of this final decision.

In accordance with clause 6.12.1(3)(ii) of the transitional chapter 6 rules the AER does not accept Integral Energy's forecast capex for the next regulatory control period. The AER's reasons for this decision are set out in section 7.8 of the draft decision and 7.5 of this final decision.

The AER's estimate of the total capex required by Integral Energy in the next regulatory control period, that reflects the capex criteria taking into account the capex factors, is set out in table 7.19 of this final decision.

8 Forecast operating expenditure

8.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision, including the NSW DNSPs' revised proposed opex allowances and the AER's conclusion on the NSW DNSPs' opex allowances for the next regulatory control period.

The opex forecasts in the NSW DNSPs' revised regulatory proposals are based on their requirements for the provision of standard control services during the next regulatory control period. The AER has reviewed these opex proposals against the requirements of the transitional chapter 6 rules.

8.2 AER draft decision

8.2.1 Country Energy

The AER considered Country Energy's proposed forecast total opex allowance of $2160 million ($2008–09), and was not satisfied that the forecast total opex proposed by Country Energy reasonably reflected the opex criteria in the transitional chapter 6 rules.[480]

On the basis of its analysis of Country Energy's proposed forecast opex allowance and the advice of Wilson Cook, the AER applied a reduction of $185 million ($2008–09) or approximately 9 per cent to Country Energy's proposed forecast opex.[481] The draft decision on Country Energy's forecast opex allowance by category is set out in table 8.1.

Table 8.1: AER draft decision on Country Energy's total opex allowance ($m, 2008–09)

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

Source: AER, *Draft decision*, p. 198.
Note: Totals may not add up due to rounding.

480 AER, *Draft decision*, p. 198.
481 AER, *Draft decision*, p. 198.

The AER allowed $4.2 million for benchmark equity raising costs for the next regulatory control period and this amount was added to the regulatory asset base (RAB).[482]

8.2.2 EnergyAustralia

The AER considered EnergyAustralia's proposed forecast total opex allowance of $3047 million ($2008–09), and was not satisfied that the forecast total opex proposed by EnergyAustralia reasonably reflected the opex criteria in the transitional chapter 6 rules.[483]

On the basis of its analysis of EnergyAustralia's proposed opex forecast and the advice of Wilson Cook, the AER applied a reduction of $410 million ($2008–09) or approximately 13 per cent to EnergyAustralia's proposed opex forecast.[484] The draft decision on EnergyAustralia's opex forecast by category, and allocated between distribution and transmission is set out in table 8.2.

Table 8.2: AER draft decision on EnergyAustralia's total opex allowance ($m, 2008–09)

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

Source: AER, *Draft decision*, pp. 200–201.
Note: Totals may not add up due to rounding.

482 AER, *Draft decision*, p. 199.
483 AER, *Draft decision*, p. 199.
484 AER, *Draft decision*, p. 199.

The AER allowed $36 million for benchmark equity raising costs for the next regulatory control period. This amount was added to the RAB.[485]

8.2.3 Integral Energy

The AER considered Integral Energy's proposed forecast total opex allowance of $1477 million ($2008–09), and was not satisfied that the forecast total opex proposed by Integral Energy reasonably reflected the opex criteria of the transitional chapter 6 rules.[486]

On the basis of its own analysis of Integral Energy's proposed opex and the advice of Wilson Cook, the AER applied a reduction of $17 million ($2008–09) or approximately 1 per cent to Integral Energy's proposed forecast opex.[487] The draft decision on Integral Energy's proposed forecast opex by category is set out in table 8.3.

Table 8.3: AER draft decision on Integral Energy's total opex allowance ($m, 2008–09)

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

Source: AER, *Draft decision*, p. 202.
Note: Totals may not add up due to rounding.

The AER allowed $0.4 million for benchmark equity raising costs for the next regulatory control period. This amount was added to the RAB.[488]

8.3 Revised regulatory proposals

8.3.1 Country Energy

Country Energy implemented the draft decision in respect of forecast opex except those aspects related to:[489]

485 AER, *Draft decision*, p. 201.
486 AER, *Draft decision*, pp. 201–202.
487 AER, *Draft decision*, p. 202.
488 AER, *Draft decision*, p. 203.

- network maintenance costs adjustment
- costs for review of voltage regulation relay settings and distribution transformer tap positions
- vegetation management asset growth escalation
- costs relating to the outcomes of a specific legal decision involving Country Energy
- self insurance costs
- debt raising costs
- equity raising costs
- certain cost escalators.

Country Energy's revised forecast opex allowance for the next regulatory control period was $2211 million ($2008–09) as set out in table 8.4.

Table 8.4: Country Energy's revised forecast opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Network operating costs	18.0	18.1	18.4	18.6	18.9	92.1
Network maintenance costs	346.8	366.2	376.9	386.8	395.9	1872.6
Other controllable operating costs	38.0	39.2	40.4	1.64	42.7	202.0
Total controllable opex	402.8	423.6	435.7	447.1	457.5	2166.7
Self insurance costs	3.9	3.9	3.9	3.9	3.9	19.5
Debt raising costs	4.0	4.5	5.0	5.5	6.1	25.0
Total opex	410.7	432.0	444.6	456.5	467.4	2211.2

Source: Country Energy, *Revised regulatory proposal,* p. 33 and Country Energy. *Opex model*, confidential.
Note: Totals may not add up due to rounding.

Country Energy accepted the AER's amortisation of equity raising costs in the draft decision, but not the amount, proposing revised equity raising costs of $55 million to be added to the RAB.[490]

8.3.2 EnergyAustralia

In the draft decision, the AER reduced EnergyAustralia's original opex proposal by $23 million following further analysis by EnergyAustralia regarding the relationship between capex and maintenance expenditure and errors identified by EnergyAustralia in its asset age profile information.[491] In its revised regulatory proposal, EnergyAustralia accepted these adjustments.[492]

489 Country Energy, *Revised regulatory proposal*, p. 19.
490 Country Energy, *Revised regulatory proposal*, p. 46.
491 AER, *Draft decision*, p. 161.
492 EnergyAustralia, *Revised regulatory proposal*, p.101.

EnergyAustralia rejected all the reductions made in the draft decision to its adjusted opex proposal. In particular, EnergyAustralia rejected the reductions of:[493]

- $214 million for network operating costs
- $31 million for network maintenance costs
- $83 million for other operating costs
- other non–controllable opex—self insurance costs and debt and equity raising costs totalling $82 million.

EnergyAustralia noted that the cost of meeting its superannuation obligations is likely to increase as a result of the poor performance of the stock market in the last year. EnergyAustralia stated that it had not yet been advised of the magnitude of these costs and intended to provide an updated assessment of the superannuation costs to the AER for the purpose of making its final decision.[494] No further information on the updated assessment was provided by EnergyAustralia.

EnergyAustralia proposed a revised total opex allowance of $2991 million ($2008–09), a reduction of $80 million from its regulatory proposal (submitted in June 2008) and $353 million greater than the amount of opex allowed in the draft decision.[495] As shown in table 8.5, this consists of forecast controllable opex of $2911 million, $30 million for self insurance costs and $51 million for debt raising costs. EnergyAustralia accepted the AER's amortisation of equity raising costs in the draft decision, but not the amount proposing revised equity raising costs of $179 million to be added to the RAB.[496]

Table 8.5: EnergyAustralia's revised forecast opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Network operating costs	206.4	215.8	219.9	224.3	227.9	1094.3
Network maintenance costs	226.9	234.4	244.6	255.0	263.6	1224.5
Other controllable operating costs	115.6	116.7	118.3	122.2	119.3	592.1
Total controllable operating costs	548.8	566.9	582.8	601.6	610.8	2910.9
Self insurance costs	5.9	5.9	5.9	5.9	5.9	29.6
Debt raising costs	7.6	9.0	10.1	11.4	12.6	50.8
Total opex	562.4	581.8	598.9	618.9	629.3	2991.3

Source: EnergyAustralia, *Revised regulatory proposal*, p. 109 and EnergyAustralia, email to the AER, 12 February 2009.
Note: Totals may not add up due to rounding.

493 EnergyAustralia, *Revised regulatory proposal*, pp. 74–107.
494 EnergyAustralia, *Revised regulatory proposal*, p. 108.
495 EnergyAustralia, *Revised regulatory proposal*, p. 109.
496 EnergyAustralia, *Revised regulatory proposal*, pp. 48–49, 107.

EnergyAustralia's rejection of the AER's adjustments is based on the following arguments:[497]

- the AER and Wilson Cook did not consider all of the material in EnergyAustralia's regulatory proposal
- the AER uncritically relied on Wilson Cook's analysis rather than supplementing it with its own analysis
- much of Wilson Cook's analysis was flawed.

EnergyAustralia provided additional information in support of its revised regulatory proposal, including four new consultancy reports.

8.3.3 Integral Energy

Integral Energy implemented the draft decision in respect of forecast opex except those aspects related to:[498]

- real labour cost escalators
- defined benefit adjustment to superannuation
- self insurance costs
- debt raising costs
- equity raising costs.

In accordance with the draft decision on equity raising costs, Integral Energy removed its proposed allowance for equity raising costs from its opex forecast, and added it to its RAB. However, Integral Energy did not accept the AER's draft decision on the amount allowed, and instead proposed to capitalise $40 million.[499] Integral Energy's revised forecast opex allowance for the next regulatory control period is $1521 million ($2008–09) as set out in table 8.6.

497 EnergyAustralia, *Revised regulatory proposal*, pp. 74–107.
498 Integral Energy, *Revised regulatory proposal*, p. 36.
499 Integral Energy, *Revised regulatory proposal*, p. 47.

Table 8.6: Integral Energy's revised forecast total opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Operating and maintenance						
Inspection	15.9	16.3	16.6	17.1	17.1	82.9
Maintenance	101.0	103.3	107.4	109.1	108.7	529.5
Other operating	50.0	50.3	53.9	56.0	57.3	267.5
Corporate support	122.6	121.2	118.6	120.6	120.6	603.7
Total controllable opex	289.6	291.0	296.5	302.7	303.8	1483.7
Self insurance costs	3.1	3.2	3.3	3.3	3.2	16.1
Debt raising costs	3.5	3.9	4.3	4.6	4.8	21.1
Total opex	296.3	298.1	304.0	310.5	311.9	1520.8

Source: Integral Energy, *Revised regulatory proposal*, p. 48 and Integral Energy, *Email to AER, Attachment*, 26 March 2009.
Note: Totals may not add up due to rounding.

8.4 Submissions

The AER received the following submissions:

- Integral Energy discussed superannuation liabilities and equity raising costs[500]
- the Energy Markets Reform Forum (EMRF) discussed the benchmark opex levels, as well as Country Energy's vegetation management[501]
- Country Energy discussed its vegetation management allowance[502]
- EnergyAustralia discussed equity raising costs, self insurance as well as prudent and efficient expenditure[503]
- Origin Energy noted that the AER should take account of the economic slowdown[504]
- the Energy Users Association of Australia (EUAA) commented on opex costs and the labour escalators.[505]

500 Integral Energy, *Revised regulatory proposal*, pp. 38–39, 44–47.
501 EMRF, pp. 41–43.
502 Country Energy, *Submission*, p. 2.
503 EnergyAustralia, *Further submission*, pp. 2–3, and 8–11.
504 Origin Energy, *Submission to the AER*, pp. 3–5.
505 EUAA, p. 18.

8.5 Issues and AER considerations

8.5.1 Country Energy

8.5.1.1 Network maintenance costs—vegetation management

AER draft decision

In the draft decision the AER noted that while Country Energy had previously received an allowance for the enhanced vegetation management for poor performing feeder segments activity, it had requested an allowance for this item again in its regulatory proposal. The AER considered that it was required to consider a prudent operator in the circumstances of Country Energy, which included the fact that Country Energy had already received an allowance for this item. The AER concluded that a prudent operator in the circumstances of Country Energy would not require this allowance again.[506]

Further, while the AER accepted that the associated forecast expenditure would be needed, it considered that where customer charges were increased to finance a specific activity in the current regulatory control period, then charges should not be again increased to deliver that service. Accordingly, the AER reduced the opex allowance by $135 million ($2008–09).[507]

Revised regulatory proposal

In its revised regulatory proposal, Country Energy explained that the Design, Reliability and Performance Licence Conditions were imposed on it by the Minister for Energy on 1 August 2005 under the auspices of the I (NSW). To comply with the new licence conditions Country Energy submitted a cost pass through application to IPART in December 2005. Country Energy noted that IPART approved an annual opex pass through allowance of $45 million ($2008–09) for the three years, 2006–07 to 2008–09.[508]

Country Energy noted that the imposed licence conditions included the requirement for compliance with the feeder class reliability standards as well as the individual feeder reliability standards.

Country Energy indicated to the AER that it has to date spent the annual allowance in each of these years entirely on vegetation management projects, improving feeder class reliability standards. Accordingly, Country Energy submitted that it has, in fact, allocated all of its opex allowance under the cost pass through to projects which are attributable to the pass through event.[509]

Country Energy also explained that it has developed a new methodology to allow it to forecast its vegetation management expenditure requirements more accurately. The new methodology has also enabled Country Energy to rank projects in terms of priority. For example, those projects which were necessary to uphold the safety, security and reliability of the network were given priority. This has allowed it to comply fully with its licence conditions and obligations in respect of reliability, safety and network performance.

506 AER, *Draft decision*, pp. 172–173.
507 AER, *Draft decision*, pp. 172–173.
508 Country Energy, *Revised regulatory proposal*, p. 23.
509 Country Energy, *Revised regulatory proposal*, p. 23 and Country Energy, *Email to AER*, 24 February 2009.

Accordingly, Country Energy considered there was robust rationale for it to allocate the money to those projects which were not specifically identified in the pass through application but were attributable to the pass through event.[510]

Submissions

Country Energy reiterated its position in the revised regulatory proposal that it believed section 7A(2) of the NEL requires the AER to set regulatory allowances such that Country Energy has the opportunity to recover the efficient costs of providing direct control services. Country Energy added that the NER is also in support of its position.[511]

EMRF considered that if the vegetation management costs for the first three years of the next regulatory control period are not allowed, there can be no logical basis to allow the costs for the last two years of the next regulatory control period.[512]

AER considerations

In making the draft decision, the AER was aware that IPART had allowed Country Energy's pass through application in 2006 which was attributable to a change in licence conditions.[513] Under the pass through Country Energy was provided with an opex allowance for the incremental costs relating to compliance with the licence conditions. In its regulatory proposal Country Energy again proposed (this time to the AER) an allowance for vegetation management to meet the licence conditions as part of its opex forecast.[514]

The AER's primary concern with Country Energy's regulatory proposal was it implied that consumers would be required to pay for the same service twice—once as a result of the pass through and now under this distribution determination. Further, the AER was concerned that this would be an inefficient outcome which was contrary to the regulatory regime.

In its revised regulatory proposal, and in subsequent correspondence with the AER, Country Energy clarified the way that it had spent its opex allowance under the pass through.

Country Energy informed the AER that following the pass through application that it made to IPART it became aware that there were other projects (also attributable to the change in licence conditions but which were not specifically identified in the pass through application) which it considered were of a higher priority.[515] The AER notes Country Energy developed strategies to assess and prioritise inspection and maintenance risk levels. These strategies enabled Country Energy to identify and rank inspection, vegetation control, and maintenance related work activities across the entire network with the aim of ensuring an efficient use and prioritisation of limited resources across the entire network.[516]

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510 Country Energy, *Revised regulatory proposal*, p. 24.
511 Country Energy, *Submission*, p. 2.
512 EMRF, pp. 41–42.
513 IPART, *NSW Distribution Network Cost Pass Through Review—Statement of Reasons for decision,* 5 May 2006, pp. 2–3.
514 Country Energy, *Regulatory proposal*, p. 54.
515 Country Energy, *Revised regulatory proposal*, p. 22.
516 Country Energy, *Revised regulatory proposal*, p. 20.

While Country Energy did not spend its opex allowance on the specific vegetation management set out in its pass through application, it has confirmed that it did spend most of the opex allowance on vegetation management which was attributable to the pass through event—that is, the change in licence conditions.[517]

As such, Country Energy has alleviated the AER's key concerns by demonstrating that it is not proposing that consumers pay for the same service twice. Rather, in the current regulatory control period Country Energy undertook projects that were of a higher priority and provided benefits to customers.

Wilson Cook commented on whether the proposed expenditure is efficient and reasonable. The AER also notes the concern of the EMRF regarding the appropriateness of the allowance. In the draft decision, based on Wilson Cook's advice, the AER considered that the vegetation management expenditure is necessary for the next regulatory control period.[518] Country Energy stated that its forecast methodology for vegetation management produced comparable results to Ergon Energy's expenditure. Ergon Energy's expenditure was assessed as prudent and efficient by the Queensland regulator.[519]

The AER notes that Wilson Cook was satisfied that the profiling data used by Country Energy provided a reasonable basis for estimating the required works.[520] In reviewing Country Energy's vegetation management allowance, Wilson Cook reviewed the comparison with Ergon Energy. Wilson Cook considered that the comparison showed that Ergon Energy had a similar profile of vegetation density and that after allowing for differences in cycles and size, Country Energy's proposed expenditure was comparable to that incurred by Ergon Energy.[521]

Based on the advice of Wilson Cook and the information setting out the comparison with Ergon Energy, the AER is satisfied that the proposed vegetation management expenditure reasonably reflects the efficient costs a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal and additional information, the AER is satisfied that the reinstatement of $135 million ($2008–09) for vegetation management expenditure in Country Energy's forecast opex 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.

8.5.1.2 Review of voltage regulation relay settings and distribution transformer tap positions

AER draft decision

The AER identified that Country Energy incorrectly included the costs for review of voltage regulation relay setting and distribution transformer tap positions as a capex item

517 Country Energy, *Email to the AER – Attachment*, 24 February 2009, p. 2.
518 AER, *Draft decision*, p. 172.
519 Country Energy, *Revised regulatory proposal*, pp. 24–25.
520 Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 4—Country Energy*, p. 41.
521 Wilson Cook, *Volume 4*, p. 41.

when it should have been expensed as an operating cost. As such the AER decided to reduce Country Energy's capex by $12 million ($2008–09).[522]

Revised regulatory proposal

Country Energy agreed with the AER decision to remove the program from capex. In its revised regulatory proposal Country Energy increased the opex category of other network maintenance costs by the amount of $12 million ($2008–09).[523]

AER considerations

In the draft decision the AER identified that the $12 million ($2008–09) for costs for review of voltage regulation relay setting and distribution transformer tap positions should not be included in the capex allowance. The AER acknowledges that while this amount was removed from the capex allowance for the draft decision it was not added to the opex allowance. The AER agrees with Country Energy that this amount should be included in its forecast opex for the next regulatory control period.

The AER reviewed Country Energy's revised capex and opex models and identified that, while Country Energy added this expenditure item to the opex allowance and accepted that it should not be included as capex, it had not removed it from the proposed capex allowance. Country Energy subsequently advised the AER that this item had been inadvertently retained in its revised capex allowance and confirmed that this item should be removed from the reliability and quality of service enhancement capex category.[524] This matter is further discussed in section 7.5.4.3.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal and additional information, the AER is satisfied that Country Energy's inclusion of the costs of voltage regulation relay setting and distribution transformer tap positions in its forecast opex allowance 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.

8.5.1.3 Vegetation management asset growth escalator

AER draft decision

The AER decided that the application of an asset growth escalator to vegetation management was not appropriate. Based on the advice of Wilson Cook, the AER considered it unlikely that growth capex would be the key driver of the quantity of vegetation management required.[525] Rather, the AER considered that vegetation management is likely to be more heavily influenced by service quality issues and compliance with licensing and other requirements as demonstrated in the provision of a pass through allowance by IPART in 2005. Accordingly, the AER reduced the opex allowance by $25 million ($2008–09).[526]

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522 AER, *Draft decision*, p. 151.
523 Country Energy, *Revised regulatory proposal*, pp. 26–27.
524 Country Energy, *Email to AER*, 20 February 2009.
525 AER, *Draft decision*, p. 173.
526 AER, *Draft decision*, p. 173.

Revised regulatory proposal

Country Energy rejected the draft decision to reduce the opex allowance for the increased operational costs associated with vegetation management in proximity to newly commissioned lines.

Country Energy asserted that all newly constructed lines would incur at least one, possibly two, vegetation clearing cycles during the next regulatory control period and that these inspection and trimming operations incur costs.[527]

Country Energy also stated that the asset growth escalator was intended to be applied at an enterprise level and therefore considered that it would not be appropriate to apply the same factors at each cost category level.[528]

Consultant review

Wilson Cook stated that the rationale in its final report (for the draft decision) was based on its understanding that in essence, a completely new approach was being taken to vegetation management. This new approach would involve a work program supported by a substantial increase in expenditure which would be put towards a more aggressive clearing of existing line routes to satisfy licence conditions.

Wilson Cook noted that any new routes will also be subjected to the same aggressive program. The cost of clearing any new line routes established in the next regulatory control period should be capitalised as part of the related construction cost.[529] Wilson Cook noted that not all new lines will need to be cleared a second time.[530]

Accordingly, Wilson Cook considered that any additional costs relating to new lines would likely be minimal and that there was no need to apply a workload escalator to the program. Accordingly, Wilson Cook remained of the view that it is not appropriate to apply the asset growth escalator to vegetation management, at least in the next regulatory control period.[531]

AER considerations

The AER notes that Country Energy has commenced a new approach to vegetation management. The change has been brought about largely by new licence conditions. The AER notes that Country Energy will receive a substantial increase in its opex allowance in order to maintain existing line routes. The AER agrees with Wilson Cook that it would be reasonable to expect that much of the additional costs could be accommodated through this general vegetation management allowance.

The AER notes that Country Energy and Wilson Cook agreed that new line routes are cleared prior to construction. Further, Wilson Cook also agreed that the costs associated with these works should be capitalised. The AER considers there is an issue regarding how many clearing cycles will be incurred during the next regulatory control period.

527 Country Energy, *Revised regulatory proposal*, p. 27
528 Country Energy, *Revised regulatory proposal*, p. 27.
529 Wilson Cook, *Country Energy review*, p. 7.
530 Wilson Cook, *Country Energy review*, p. 7.
531 Wilson Cook, *Country Energy review*, p. 7.

The AER notes Country Energy's assertion that all newly constructed lines will incur at least one, possibly two, vegetation clearing cycles during the next regulatory control period. However, the AER considers that this assertion is not consistent with the timeframe envisaged in Country Energy's revised regulatory proposal. The timeframe envisaged in its revised regulatory proposal is that it will take two to three years for newly constructed lines to incur a full cycle. As such, based on Country Energy's revised regulatory proposal, any newly constructed lines in years four or five of the next regulatory control period will not incur one clearing cycle until the following regulatory control period. It is also highly unlikely that any lines constructed in year three of the next regulatory control period will incur one clearing cycle in the remainder of the period. Similarly, only the assets constructed in year one would have any possibility of incurring two clearing cycles. However, based on Country Energy's average clearing cycles the AER considers that it would be highly unlikely that any would incur a second clearing cycle.

The AER notes Country Energy's claim that the asset growth escalator should not have been removed from any particular individual category. The AER agrees with Wilson Cook that Country Energy has not demonstrated why this is inappropriate.

The AER considers that Country Energy has failed to adequately address the AER's concerns set out in its draft decision regarding the asset growth escalator—that is, it was unlikely that the quantity of vegetation management would be driven principally by growth capex and so it was inappropriate to apply an asset growth escalator.

The AER considers that it is likely that up to three out of every five newly constructed line routes will not undergo a complete vegetation clearing cycle in the next regulatory control period. The AER does not consider that Country Energy has justified why it would be appropriate to include the asset growth escalator.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal and additional information, the AER is not satisfied that Country Energy's approach in applying a vegetation management asset growth escalator to its forecast opex 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. Following a request from the AER, Country Energy advised that the AER's conclusion to remove the effect of this escalator results in a reduction of $26 million ($2008–09) to its forecast opex.[532]

8.5.1.4 Forecast costs of project associated with Sheather decision

AER draft decision

In its regulatory proposal, Country Energy cited a recent case in which the NSW Court of Appeal found Country Energy to have breached its duty of care.[533] Country Energy proposed to include a nominated pass through event for legal obligations which are imposed on it and which do not fall within any of the defined events under the NER.[534]

[532] Country Energy, email response to AER, 17 April 2009.
[533] Sheather v Country Energy [2007] NSWCA 179 (24 July 2007).
[534] Country Energy, *Revised regulatory proposal*, pp. 169–170.

In the draft decision, the AER decided that it was not the type of event which the NER intended should be included as a nominated pass through event. Rather, it was more appropriate that Country Energy include these types of costs in its forecast opex allowance at the next regulatory control period.[535]

Revised regulatory proposal

In its revised regulatory proposal, Country Energy set out forecast costs for mitigating the risk associated with the legal decision. Country Energy identified potential actions which may mitigate its risk or exposure, such as:[536]

- placing a limited number of markers above roadways by means of high tower, aerial attachment or dropping the line
- marking the line in accordance with the Australian Standard (AS), AS 3891.1, by means of high tower, aerial attachment or dropping the line
- relocating the line
- painting the poles.

Country Energy also set out its method for determining the best approach to mitigating its risks. Country Energy noted it will consider the length, height and surrounding topography to establish a risk matrix. The risk matrix will be refined following a survey of the spans undertaken during the normal asset inspection process. Country Energy stated the survey would collect information on a number of factors including:[537]

- surrounding land use
- visibility of the lines
- surrounding aircraft flight paths
- location of hang gliding clubs and the like
- any other factors considered relevant by the working group.

Country Energy forecast that 50 per cent of its spans will require remedial action. Country Energy proposed that the work be carried out over a 10 year period with work commencing from 1 July 2010 on the highest risk spans. Country Energy forecast that the average remedial action will be to install markers on the lines in accordance with AS 3891.1 and that the supporting poles will have to be upgraded to carry the additional weight.[538]

Country Energy calculated the total cost of pole replacement and line marking to be $40 million ($2008–09). Country Energy therefore increased the opex category of other network maintenance costs by the amount of $10 million per annum commencing 1 July 2010.[539]

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[535] AER, *Draft decision*, pp. 281–282.
[536] Country Energy, *Revised regulatory proposal*, pp. 28–29.
[537] Country Energy, *Revised regulatory proposal*, p. 28.
[538] Country Energy, *Revised regulatory proposal*, pp. 28–29.
[539] Country Energy, *Revised regulatory proposal*, pp. 28–29.

Consultant review

The AER requested Wilson Cook to advise it on the reasonableness of the proposed project costs associated with the Sheather decision. Wilson Cook did not consider it was able to comment on the likely cost as the necessary survey had not been carried out and the scope and nature of the work involved was unknown. While Wilson Cook considered that Country Energy's approach was reasonable it considered the costs were indeterminate.[540]

The AER engaged Energy and Management Services Pty Ltd (EMS) to advise it on the proposed project costs associated with the Sheather decision. EMS considered that Country Energy's proposal for an allowance of $40 million was not based on assumptions or forecasts that could be described as 'sufficiently robust' or 'reasonable'.[541] However, EMS considered the unit costs adopted by Country Energy were reasonable.[542] EMS stated that work would be required to fulfil the Coroner's recommendation that a strategy and feasibility study be developed to identify, prioritise and mark power lines at risk of a wire strike. Ideally, the Civil Aviation Safety Authority and Country Energy would work together to formulate an optimally efficient and effective solution. Further, consultants' advice should be obtained, and overseas practices and alternative technologies should be considered.[543]

EMS noted that further work was needed to develop an effective and efficient fulfilment of the Coroner's recommendation. EMS also noted that once Country Energy engaged in appropriate consultation and robust analysis this would likely lead to a significant change in forecast expenditure. Accordingly, EMS advised that the AER may wish to reconsider whether this matter should be allowed as a cost pass through event.[544]

AER considerations

In the draft decision the AER decided that costs associated with the Sheather decision were not the type of costs that should be provided for by way of a nominated pass through event. In response, Country Energy included in its revised regulatory proposal forecasts of the costs associated with mitigating its exposure to these types of claims.

Wilson Cook stated in relation to these costs that it considered:

> …the cost indeterminate at present given that the requisite survey has not been carried out, the scope and nature of the work involved is unknown and the specialised nature of the work makes it difficult to cost.[545]

The AER notes Wilson Cook's advice that it was unable to assess the reasonableness of the proposed costs as the necessary scoping and consultation had not been undertaken. The AER also notes EMS's advice:

> Country Energy appear to be intending to use only their own resources to identify and prioritise power lines that are at risk of wire strike. No mention is made of

540 Wilson Cook, *Country Energy review*, p. 8.
541 EMS, *Commentary on Country Energy's proposal relating to the marking of power lines for aviation safety*, 19 March 2009, p. 5.
542 EMS, p. 5.
543 EMS, p. 6.
544 EMS, p. 6.
545 Wilson Cook, *Country Energy review*, p. 8.

> interaction with the Civil Aviation Safety Authority (CASA) or other bodies with expertise in aviation, to assist in the task. EMS suggests that Country Energy does not have aviation knowledge or expertise and, regardless of the bona fides of their intentions, a work plan based on insufficient or misguided expertise is certain to fall short of optimum levels of effectiveness and economic efficiency.[546]

The AER considers that Country Energy will need to consult with relevant regulatory authorities to determine where the areas of high risk are and adopt appropriate solutions to the identified risk.

EMS also advised that Country Energy's methodology relied on assumptions which do not appear to be based on any sound rationale. The particular assumptions singled out by EMS as being questionable are:[547]

- the length of a span at which a wire is deemed to be at risk of wire strike
- the estimate that 50 per cent of spans will require remediation
- the proposal to invoke AS 3891.1.

As such EMS considered that Country Energy's revised regulatory proposal is not sufficiently robust to justify a proposed expenditure of $40 million.

The AER considers that the mitigation of aviation hazards caused by power lines is a complex issue. The AER understands that Country Energy has not yet been able to undertake the necessary scoping work, research and consultation required to provide robust specification of the necessary work and associated costs. Country Energy has had limited time in which to undertake this work as the Coronial findings were only handed down in August 2008.[548]

Accordingly, the AER agrees with EMS that these costs may be foreseeable but they cannot be forecast on a reliable basis and are therefore best dealt with by a nominated cost pass through event. The AER notes that this approach is consistent with Country Energy's regulatory proposal of June 2008. This matter is discussed further in section 15.5.3.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal and additional information, the AER is not satisfied that Country Energy's approach in including the costs associated with the Sheather decision to its forecast opex 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. Following a request from the AER, Country Energy advised that the AER's conclusion results in a reduction of $40 million ($2008–09) to its forecast opex.[549]

[546] EMS, p. 4.
[547] EMS, pp. 4–5.
[548] EMS, p. 1.
[549] Country Energy, *Response to AER*, 17 April 2009.

8.5.2 EnergyAustralia

8.5.2.1 Step changes in opex

AER draft decision

In the draft decision, the AER concluded that the majority of proposed step changes included in EnergyAustralia's opex should be removed. Based on this conclusion EnergyAustralia advised the AER that the reductions to opex would be $303 million ($2008–09) for costs associated with step changes in opex, including $214 million for network operating costs, $19 million for maintenance costs and $70 million for other operating costs.[550]

Revised regulatory proposal

EnergyAustralia rejected the adjustments the AER made to proposed step changes in the opex forecast in the draft decision. EnergyAustralia was critical of Wilson Cook's advice to the AER and claimed that the AER failed to critically test Wilson Cook's advice and to properly review the material submitted by EnergyAustralia in support of its regulatory proposal.[551]

In support of its proposed step changes in opex, EnergyAustralia provided additional information in its revised regulatory proposal, including three new consultancy reports.

Wilson Cook analysis

EnergyAustralia suggested there were a number of problems with Wilson Cook's advice to the AER in relation to step changes in opex.[552] In particular, EnergyAustralia stated:

- Wilson Cook's criteria for accepting step changes in costs are not consistent with the NER, and are too narrow (for example, they do not include risk mitigation) and were not applied consistently, resulting in the rejection of prudent expenditure
- Wilson Cook's bottom up analysis includes simplifying assumptions (specifically, that opex step changes would be off–set by efficiencies) to avoid a detailed review of the step changes
- Wilson Cook's top down benchmarking analysis, which the AER relied on in accepting Wilson Cook's advice on step changes, has significant methodological errors in the application of the cost scale variable analysis (this issue is discussed separately in section 8.5.2.4).

EnergyAustralia provided a report by Huegin Consulting Group (Huegin) to support its criticisms of Wilson Cook's analysis.[553]

In addition to the Huegin report, EnergyAustralia provided further material which it considered demonstrated the prudence and efficiency of its proposed step changes in opex, including reports by Concept Economics[554] and PricewaterhouseCoopers.[555]

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550 EnergyAustralia, *Response to information request*, confidential, 20 November 2008.
551 EnergyAustralia, *Revised regulatory proposal*, pp. 76–84.
552 EnergyAustralia, *Revised regulatory proposal*, p. 78.
553 Huegin Consulting Group, *EnergyAustralia regulatory proposal review (opex)*, confidential attachment 9A, 13 January 2009.

AER reliance on Wilson Cook advice

EnergyAustralia suggested that, in making its draft decision, the AER did not refer to the substantial material provided by EnergyAustralia as part of its June 2008 regulatory proposal and that it appeared the AER had relied exclusively on Wilson Cook's advice. EnergyAustralia stated the AER is required to consider the detail of EnergyAustralia's regulatory proposal itself. EnergyAustralia also stated the AER cannot uncritically accept the AER's consultant's advice.[556]

Submissions

EnergyAustralia reiterated the claim it made in its revised regulatory proposal that the AER should not have rejected the step changes in opex proposed by EnergyAustralia. In further support of this view, EnergyAustralia provided a report by NERA Economic Consulting (NERA) which found that EnergyAustralia's opex forecasts give due consideration to prudence and efficiency in accordance with the NER requirements.[557] EnergyAustralia highlighted NERA's view that it may be incorrect to assume that offsetting efficiencies associated with step changes in opex will occur in the same regulatory control period as the expenditure is incurred. NERA also noted that Wilson Cook appears to have focused on productive efficiency (cost savings) and not allocative efficiency (customer benefits) in its analysis of proposed step changes.[558]

While not addressing step changes explicitly, other submissions raised issues in relation to the AER's assessment of step changes. The EMRF suggested that with such large increases in capex in both the current regulatory control period and the next regulatory control period, the NSW DNSPs (especially EnergyAustralia) should be required to achieve much larger efficiency savings in opex.[559] The EUAA suggested that the NSW DNSPs' opex is inflated and there are few efficiency improvements in the opex forecasts proposed by the NSW DNSPs. The EUAA stated that the AER should make a robust assessment of the revised opex forecasts provided by the NSW DNSPs to ensure that these expenditures are cost effective and efficient.[560]

Consultant review

In response to criticism of its step change criteria, Wilson Cook clarified its view that for acceptance as a step change, a cost ought to relate to a fundamental change in the business environment arising from outside factors or be offset by cost efficiencies in other areas or benefits to customers.[561] Wilson Cook considered whether risk mitigation should be a criterion for assessing step changes in opex and suggested that risk cannot be considered unless costs, benefits and potential adverse impacts are quantified. Wilson

554 Concept Economics, *Operating efficiencies in periods of high investment and technology change*, 13 January 2009.
555 PricewaterhouseCoopers, *Case study: EnergyAustralia's approach to incorporating efficiency gains into operational expenditure forecasts utilising its integrated asset management systems*, January 2009.
556 EnergyAustralia, *Revised regulatory proposal*, p. 78.
557 EnergyAustralia, *Further submission*, p. 9.
558 NERA, *Critique of the AER and Wilson Cook assessments of the prudence and efficiency of step changes in opex*, 16 February 2009, p. 6.
559 EMRF, pp. 35–36.
560 EUAA, p. 18.
561 Wilson Cook, *EnergyAustralia review*, p. 7.

Cook noted that little or no quantification of benefits had been attempted by EnergyAustralia and concluded that no quantification of risk was possible.[562]

Wilson Cook considered whether Huegin's proposed method of assessing step changes should be used in place of Wilson Cook's approach and decided against this. Wilson Cook stated that Huegin's analysis did not appear to have considered the efficiency or cost effectiveness of the step changes in expenditure, only their claimed necessity or unavoidable nature.[563]

Wilson Cook also considered material prepared by PricewaterhouseCoopers and Concept Economics that was related to EnergyAustralia's IT costs. Wilson Cook concluded that the PriceWaterhouseCoopers' report did not indicate the scale and timing of benefits expected to result from implementing EnergyAustralia's integrated asset management system.[564] Similarly, Wilson Cook stated that the high level conceptual analysis provided by Concept Economics should not excuse EnergyAustralia from identifying and quantifying the benefits and opex savings expected to result from its IT capex program, and when these might occur.[565]

In response to criticism of its application of the step change criteria, Wilson Cook reviewed its categorisation of the step changes in costs proposed by EnergyAustralia, taking account of additional information submitted by EnergyAustralia. Wilson Cook assessed the step changes individually to determine, amongst other things, whether the costs were necessary, efficient and resulted in quantifiable benefits in terms of cost efficiencies or customer benefits.[566]

Based on its revised bottom up analysis, Wilson Cook revised its recommended downward adjustments for step changes in EnergyAustralia's opex, from $285 million to $169 million.[567] The revised adjustments for network operating costs, network maintenance costs and other operating costs are as shown in table 8.7.

The majority ($73 million) of additional step change costs that Wilson Cook has now recommended the AER accept relate to network operating costs. Of these, most relate to property costs associated with EnergyAustralia's capex program, which Wilson Cook noted is driven, at least partly, by changes in the licence conditions for the NSW DNSPs.[568]

Of the remaining additional step change costs that Wilson Cook has now recommended that the AER accept, most ($32 million) relate to other operating costs. Of these, most relate to external obligations, such as customer emergency services, or are in lieu of workload escalation.[569]

562 Wilson Cook, *EnergyAustralia review*, p. 8.
563 Wilson Cook, *EnergyAustralia review*, p. 21.
564 Wilson Cook, *EnergyAustralia review*, p. 18.
565 Wilson Cook, *EnergyAustralia review*, p. 19.
566 Wilson Cook, *EnergyAustralia review*, p. 9.
567 Wilson Cook, *EnergyAustralia review*, p. 34.
568 Wilson Cook, *EnergyAustralia review*, p. 23.
569 Wilson Cook, *EnergyAustralia review*, p. 24.

Table 8.7: Wilson Cook's revised adjustments for step changes in opex ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Original adjustment to network operating costs	–38.9	–41.6	–39.6	–40.6	–39.5	–200.2
Revised adjustment to network operating costs	–23.3	–25.9	–24.9	–25.9	–27.4	–127.4
Original adjustment to network maintenance costs	–3.1	–3.1	–3.1	–3.1	–3.1	–15.5
Revised adjustment to network maintenance costs	–0.8	–0.8	–0.8	–0.8	–0.8	–4.0
Original adjustment to other operating costs	–12.9	–13.4	–13.9	–14.5	–14.7	–69.4
Revised adjustment to other operating costs	–7.4	–7.5	–7.6	–7.8	–7.6	–37.9
Original total adjustment for step changes	–54.9	–58.1	–56.6	–58.2	–57.3	–285.1
Revised total adjustment for step changes	–31.5	–34.2	–33.3	–34.5	–35.8	–169.3

Sources: Wilson Cook, *Volume 2 – EnergyAustralia*, pp 55, 57, 60 and Wilson Cook, *EnergyAustralia review*, pp. 24–25.
Note: Totals may not add up due to rounding.

AER considerations

The AER does not accept EnergyAustralia's suggestion that, in coming to its conclusions on step changes in the opex forecast in the draft decision, it failed to test Wilson Cook's advice and to consider the material submitted by EnergyAustralia in support of its regulatory proposal. The AER's consideration and assessment of Wilson Cook's advice and material presented by EnergyAustralia on step changes is outlined in section P.4.3 of the draft decision.[570]

The AER acknowledges that some valid criticisms were raised by EnergyAustralia and in submissions in relation to Wilson Cook's bottom up analysis of the proposed step changes, particularly the extent to which individual step changes were assessed against the step change criteria. The AER considers that Wilson Cook's revised bottom up assessment of the step changes proposed by EnergyAustralia represents a significant improvement on its original analysis and addresses the key concerns raised by EnergyAustralia and in submissions. The AER has reviewed the step change criteria and the manner in which step changes were assessed. The AER has also considered the analyses submitted by EnergyAustralia that were undertaken by Huegin, PricewaterhouseCoopers, Concept Economics and NERA.

[570] AER, *Draft decision*, pp. 598–599.

Regarding step change criteria, the AER considers that Wilson Cook's clearer identification of customer benefits as a step change criterion is appropriate because it reflects the emphasis on the quality of the DNSP's service quality in the transitional chapter 6 rules opex objectives. The AER also considers that the inclusion of this criterion addresses concerns raised by EnergyAustralia and its consultants that the step change criteria adopted by Wilson Cook were too narrow.

The AER notes EnergyAustralia's suggestion that risk mitigation should be included as one of the criteria for assessing step changes in opex. As a general point, the AER considers that expenditure for risk management is consistent with the transitional chapter 6 rules requirements because, as noted by NERA,[571] risk mitigation is to be expected from a prudent DNSP. However, the AER notes Wilson Cook's advice that risk cannot be considered unless costs, benefits and potential adverse impacts are quantified. As EnergyAustralia has provided little or no quantification of benefits associated with proposed step changes, Wilson Cook concluded that no quantification of risk was possible.[572]

The AER agrees with Wilson Cook that Huegin's analysis emphasises the need for, and avoidability of, step changes in costs without identifying the magnitude of associated cost efficiencies or customer benefits. For example, the 'consequences' criterion used by Huegin to score costs in its 'inherent, structural, systemic, realised' analysis only addresses the costs of not undertaking a proposed step change expenditure, and even then it is only in terms of the costs being significant, moderate etc.[573] As a result, while the AER notes that Huegin's analysis appropriately identifies some step changes as being warranted (such as those arising from outside factors), the AER does not consider that Huegin's analysis provides sufficient support for other step changes in costs where the magnitude of cost efficiencies or customer benefits are not quantified.

Similarly, the AER agrees with Wilson Cook that the analyses by PricewaterhouseCoopers and Concept Economics do not provide sufficient information about the magnitude and timing of cost efficiencies or customer benefits to justify EnergyAustralia's proposed step changes in IT related opex.

The AER considers that its conclusion in relation to proposed step changes in opex addresses concerns raised in submissions that the AER had failed to account for efficiency improvements in EnergyAustralia's forecast opex.

Overall, having reviewed the material put forward, the AER considers that Wilson Cook's assessment of all of EnergyAustralia's proposed step changes individually against Wilson Cook's step change criteria provides a robust assessment of the costs. The AER therefore accepts Wilson Cook's advice on the adjustments to EnergyAustralia's proposed step changes for the opex forecast.

For the reasons discussed and as a result of the AER's analysis of EnergyAustralia's revised regulatory proposal, the AER considers that adjusting EnergyAustralia's forecast opex for the step changes as recommended by Wilson Cook results in expenditure that reasonably reflects the opex criteria, including the opex objectives. In coming to this view

571 NERA, *Economic Interpretation of clauses 6.5.6 and 6.5.7 of the National Electricity Rules*, 7 May 2008, p. 13.
572 Wilson Cook, *EnergyAustralia review*, p. 8.
573 Huegin Consulting Group, confidential attachment 9A, p. 35.

the AER has had regard to the opex factors. Following a request from the AER, EnergyAustralia advised that the AER's conclusion results in a reduction of $177 million ($2008–09) to its forecast opex—comprising of $136 million for network operating costs, $4.8 million for network maintenance costs and $36 for other operating costs.

8.5.2.2 Escalation of network maintenance costs

AER draft decision

In the draft decision, the AER reduced EnergyAustralia's network maintenance expenditure proposal by $31 million ($2008–09),[574] after the $23 million adjustment related to the relationship between capex and maintenance expenditure and asset age profile information noted in section 8.3.2 of this final decision. Of this amount, $19 million was related to removing step changes in network maintenance costs proposed by EnergyAustralia (discussed in section 8.5.2.1 of this final decision). The remaining $12 million reduction in network maintenance costs made by the AER related to the exponential escalation of maintenance costs due to asset ageing that was proposed by EnergyAustralia.

Revised regulatory proposal

EnergyAustralia rejected the $12 million reduction the AER made to the network maintenance costs that were related to the escalation of maintenance costs due to asset ageing proposed by EnergyAustralia.[575] In support of this position, EnergyAustralia suggested that Wilson Cook's advice on the relationship between asset age and maintenance costs is flawed because:[576]

- it is inconsistent with the views of engineering experts
- it does not take into account the theoretical basis for EnergyAustralia's maintenance model
- Wilson Cook's regression analysis of the relationship between asset age and maintenance costs is flawed.

EnergyAustralia suggested that it appeared the AER did not test Wilson Cook's analysis or undertake additional analysis of the documentation of EnergyAustralia's maintenance model.[577]

EnergyAustralia provided a report from Sinclair Knight Merz Pty Ltd (SKM) in support of the assumptions in EnergyAustralia's maintenance model, particularly the exponential relationship between maintenance costs and asset age.[578] The Huegin report provided by EnergyAustralia also addressed this issue.[579] EnergyAustralia suggested the SKM report provides strong additional theoretical and practical support for EnergyAustralia's maintenance model and is far more detailed and transparent than Wilson Cook's analysis.[580] EnergyAustralia also suggested that the SKM report raises concerns with Wilson Cook's analysis, on the basis of its New Zealand experience, of the relationship

574 AER, *Draft decision*, p. 176.
575 EnergyAustralia, *Revised regulatory proposal*, p. 94.
576 EnergyAustralia, *Revised regulatory proposal*, p. 95.
577 EnergyAustralia, *Revised regulatory proposal*, p. 95.
578 EnergyAustralia, *Revised regulatory proposal*, attachment 9E.
579 Huegin Consulting Group, confidential attachment 9A, p. 82.
580 EnergyAustralia, *Revised regulatory proposal*, p. 98.

between maintenance expenditure and asset age. EnergyAustralia therefore suggested the AER should not use Wilson Cook's analysis to reject EnergyAustralia's forecast of maintenance expenditure.[581]

As discussed in section 8.5.2.1 in relation to proposed step changes in opex, EnergyAustralia suggested that Wilson Cook's composite scale variable benchmark analysis is flawed.[582] As Wilson Cook relied on this analysis to determine a substitute forecast for maintenance costs, which was based on the mid–point between EnergyAustralia's proposed growth rate and Wilson Cook's estimated growth rate, EnergyAustralia questioned the robustness of Wilson Cook's substitute forecast.

EnergyAustralia also stated that alternative benchmark analysis of its maintenance costs conducted by Huegin, which showed that EnergyAustralia's maintenance expenditure is normal compared to other DNSPs, illustrates that benchmarking can yield a number of different outcomes and therefore should not be relied on as the basis of a substitute estimate.[583]

Consultant review

Wilson Cook examined the SKM report submitted by EnergyAustralia and maintained its position that the maintenance workload escalation applied by EnergyAustralia is not robust and is likely to overstate efficient costs during the next regulatory control period.[584]

In confirming its earlier conclusion, Wilson Cook noted again that exponentially increasing costs proposed by SKM are seldom observed in practice and that such a fit overemphasises the end–of–life characteristic that applies to only a small proportion of the asset population. Wilson Cook suggested that SKM acknowledged this by commenting that '...with ageing assets being replaced as they approach their economic life, the numbers of assets at the 'top end' of the curve are generally quite low'.[585]

Wilson Cook stated that it appeared that SKM had confused exponentially distributed failure times with exponential failure rates. Wilson Cook suggested that if SKM accepted that wear–out failure is described by an exponential curve, as SKM stated in section 3.1 of its report, then SKM should have concluded that the relationship between failure rate and asset age, and therefore the implied cost of failures against age, is flat or linear.[586]

Wilson Cook also queried SKM's interpretation of the case studies presented in its report in support of an exponential relationship between maintenance costs and asset age. For example, Wilson Cook stated that SKM's conclusions in relation to circuit breaker maintenance costs are overly influenced by the maintenance characteristics of 66 kV circuit breakers, which make up only a small proportion of EnergyAustralia's circuit breakers. Wilson Cook indicated that circuit breakers of other voltages are more common and do not show an exponential relationship between maintenance costs and age.[587]

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[581] EnergyAustralia, *Revised regulatory proposal*, p. 99.
[582] EnergyAustralia, *Revised regulatory proposal*, p. 100.
[583] EnergyAustralia, *Revised regulatory proposal*, p. 101.
[584] Wilson Cook, *EnergyAustralia review*, p. 31.
[585] Wilson Cook, *EnergyAustralia review*, p. 27.
[586] Wilson Cook, *EnergyAustralia review*, p. 28.
[587] Wilson Cook, *EnergyAustralia review*, p. 28.

Wilson Cook responded to criticisms of its use of New Zealand data to examine the relationship between average maintenance costs and average asset age.[588] For example, Wilson Cook suggested that, contrary to SKM's view,[589] the scope of maintenance work and work practices in Australia and New Zealand are more alike than different. In response to SKM's claim that vegetation management costs are lower in New Zealand than in Australia,[590] Wilson Cook noted that vegetation management costs should be uncorrelated to network age. It suggested that if vegetation management costs are lower in New Zealand, this would highlight, rather than disguise, relative cost differences due to differences in the average age of networks. Wilson Cook also indicated that it had accounted for differences in network type between the NSW DNSPs and that its findings in relation to its New Zealand experience only added weight to its concerns, which were established on other grounds.

Wilson Cook rejected EnergyAustralia's claim that it was incorrect to base maintenance cost escalation on the mid–point between EnergyAustralia's estimate and that proposed by Wilson Cook as an alternative estimate. Rather, Wilson Cook suggested that it was common to accept a mid–point (or some other point) between upper and lower estimates when there is reason to believe that neither value is suitable for use without adjustment and where there is no better basis of calculation.[591] As outlined in its report, Wilson Cook considered that the rate of maintenance escalation proposed by EnergyAustralia is too high.[592] In addition, Wilson Cook suggested that maintenance escalation based on its proposed size escalator may be too low because EnergyAustralia's replacement capex is directed heavily at transmission, sub–transmission and zone substation assets, not at distribution assets where it is expected that many maintenance costs lie. On this basis, Wilson Cook suggested that some increase in maintenance costs above that attributable to size alone could be expected. For these reasons, Wilson Cook has maintained its recommendation of a rate of escalation of EnergyAustralia's maintenance costs at the mid–point between EnergyAustralia's estimate and that based on Wilson Cook's new size escalator.[593]

Wilson Cook indicated that its revised benchmarking analysis (discussed in section 8.5.2.4) results in a slightly lower growth rate for the maintenance size escalator than its previous benchmarking analysis. In particular, the mid–point escalation rate for network maintenance costs has been adjusted to eight per cent instead of nine per cent. As a result, Wilson Cook revised its recommended reduction to EnergyAustralia's network maintenance costs to $28 million, as shown in table 8.8.[594]

588 Wilson Cook, *EnergyAustralia review*, p. 28–29.
589 SKM, *Response to Wilson Cook commentary on O&M/age profile modelling*, p. 14–16.
590 SKM, *Response to Wilson Cook commentary on O&M/age profile modelling*, p. 15.
591 Wilson Cook, *EnergyAustralia review*, p. 32.
592 Wilson Cook, *EnergyAustralia review*, p. 27.
593 Wilson Cook, *EnergyAustralia review*, p. 32.
594 Wilson Cook, *EnergyAustralia review*, p. 32.

Table 8.8: Wilson Cook's revised adjustments for maintenance workload escalation ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Original adjustment for maintenance workload escalation	–3.0	–2.0	–3.0	–4.0	–6.0	–18.0
Revised adjustment for maintenance workload escalation	–3.2	–4.0	–5.5	–6.4	–8.6	–27.7

Source: Wilson Cook, *Volume 2 – EnergyAustralia*, p. 57 and Wilson Cook, *EnergyAustralia review*, p. 32.

Note: The adjustment for maintenance workload escalation in the draft decision was based on EnergyAustralia's modelling of the impact of Wilson Cook's recommended approach as accepted by the AER, not Wilson Cook's estimate of the impact.

AER considerations

The AER does not accept EnergyAustralia's suggestion that it did not test Wilson Cook's analysis or review documentation of EnergyAustralia's maintenance model in coming to its conclusions on maintenance costs and asset ages. In the draft decision, the AER considered Wilson Cook's advice on these costs along with material presented by EnergyAustralia. For example, the AER accepted EnergyAustralia's position that, other things being equal, the level of maintenance expenditure needed on a network will increase as the network ages. However, the AER noted Wilson Cook's concerns regarding the determination of the relationship between asset age and maintenance and the application of that to determine future maintenance workloads. Having reviewed EnergyAustralia's proposal and the Wilson Cook assessment, the AER considered that reducing the network maintenance expenditure forecast as recommended by Wilson Cook would reflect the efficient costs that a prudent operator would require to achieve the opex objectives.[595]

The AER notes that some of the material presented by EnergyAustralia appears to suggest that an exponential relationship exists between maintenance costs and asset ageing. However, the AER questions the extent to which this relationship applies to all of a DNSP's assets. While material presented by Wilson Cook[596], SKM[597] and Huegin[598] suggests that an exponential relationship may exist between maintenance costs and assets nearing the end of their economic life, the proportion of such assets in a DNSP's total asset base is generally quite low as noted by Wilson Cook[599] and SKM.[600] The AER further notes Wilson Cook's observation that exponentially increasing costs are seldom observed in practice. As a result, the AER does not consider that EnergyAustralia's revised regulatory proposal provides a convincing case that the relationship between maintenance costs and asset age is exponential.

595 AER, *Draft decision*, pp. 602–603.
596 Wilson Cook, *EnergyAustralia review*, p. 27.
597 SKM, *Response to Wilson Cook commentary on O&M/age profile modelling*, p. 10.
598 Huegin Consulting Group, confidential attachment 9A, pp. 82–84.
599 Wilson Cook, *EnergyAustralia review*, p. 27.
600 SKM, *Response to Wilson Cook commentary on O&M/age profile modelling*, p. 11.

Regarding Wilson Cook's calculation of a substitute rate of maintenance escalation, the AER considers that it is acceptable to use a mid–point between upper and lower estimates when there is reason to believe that a more reasonable value lies somewhere between these estimates. As discussed above, the AER considers that the exponential rate of maintenance escalation proposed by EnergyAustralia is too high. The AER agrees with Wilson Cook's assessment that maintenance escalation based on its proposed escalator estimate may be too low. As a result, the AER accepts Wilson Cook's recommendation of a mid–point rate of escalation of EnergyAustralia's network maintenance costs.

For the reasons discussed and as a result of the AER's analysis of EnergyAustralia's revised regulatory proposal, the AER considers that adjusting EnergyAustralia's opex for the escalation of maintenance costs due to asset ageing as recommended by Wilson Cook results in expenditure that reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors. Following a request from the AER, EnergyAustralia advised that the AER's conclusion results in a reduction of $22 million ($2008–09) to its forecast opex.

8.5.2.3 Escalation of asset management and project management costs

AER draft decision

In the draft decision, the AER reduced EnergyAustralia's forecast of other operating costs by $83 million ($2008–09).[601] Of this amount, $70 million was related to removing step changes in other costs proposed by EnergyAustralia (discussed in section 8.5.2.1). The remaining $13 million reduction in other operating costs made by the AER related to the escalation of costs associated with asset management and project management that was proposed by EnergyAustralia.

Revised regulatory proposal

EnergyAustralia rejected the reduction of $13 million to its forecast opex that was related to the escalation of costs associated with asset management and project management as set out in the draft decision.[602] EnergyAustralia suggested that Wilson Cook had not taken into account material presented by EnergyAustralia in its regulatory proposal and in response to questions raised by Wilson Cook during August 2008.[603] EnergyAustralia also suggested that the AER relied on Wilson Cook's advice without undertaking further examination of its recommended adjustment.[604]

EnergyAustralia rejected Wilson Cook's recommendation that the workload escalator be based on the number of network division staff because this does not capture the increase in total operating costs of the asset management and project management branches.[605] In particular, EnergyAustralia suggested that staff numbers do not take into account that EnergyAustralia intends to rely increasingly on external advice in developing best practice maintenance policies and that this will be a significant portion of the total costs of the asset management and project management divisions.[606]

601 AER, *Draft decision*, p. 176.
602 EnergyAustralia, *Revised regulatory proposal*, p. 101.
603 EnergyAustralia, *Revised regulatory proposal*, pp. 101–102.
604 EnergyAustralia, *Revised regulatory proposal*, p. 101.
605 EnergyAustralia, *Revised regulatory proposal*, pp. 101–102.
606 EnergyAustralia, *Revised regulatory proposal*, p. 102.

Consultant review

Having analysed EnergyAustralia's revised regulatory proposal, Wilson Cook maintained its view that asset management and project management costs should be escalated in line with growth in network division staff rather than real growth in the capex program, as proposed by EnergyAustralia.[607]

Wilson Cook stated that EnergyAustralia had not adequately justified the link between opex activities and capex.[608] For example, Wilson Cook advised that maintenance planning, which is included in asset management and project management costs, is likely to relate only to the overall increase in assets under management, which exhibits a much smaller expected growth rate than the capex program.[609]

Wilson Cook also stated that EnergyAustralia had made conflicting statements in relation to what activities are associated with asset management and project management costs.[610] In particular, while EnergyAustralia claimed that asset management and project management costs related to maintenance planning activities, such as maintenance planning, reliability analysis and branch management, it also stated that asset management and project management costs included capital–related activities, such as governance administration and monitoring and reporting of the capital program. Wilson Cook remained of the view that capital–related activities directly related to the capital program should be capitalised.[611]

In reviewing the escalation of asset management and project management costs, Wilson Cook advised that the growth escalator should only be applied to the variable component of expenditure, which is approximately 90 per cent of the total costs.[612] As a result, Wilson Cook revised its recommended adjustment for escalation of asset management and project management costs downwards slightly, from $13 million to $12 million, as shown in table 8.9.[613]

Table 8.9: Wilson Cook's revised adjustments to asset management and project management costs ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Original adjustment to asset management and project management costs	–2.0	–2.0	–3.0	–3.0	–3.0	–13.0
Revised adjustment to asset management and project management costs	–1.7	–2.0	–3.0	–3.2	–2.4	–12.3

Source: Wilson Cook, *Volume 2 – EnergyAustralia*, p.58, and Wilson Cook, *EnergyAustralia review*, p. 33.

607 Wilson Cook, *EnergyAustralia review*, p. 33.
608 Wilson Cook, *EnergyAustralia review*, p. 33.
609 Wilson Cook, *EnergyAustralia review*, p. 33.
610 Wilson Cook, *EnergyAustralia review*, p. 33.
611 Wilson Cook, *EnergyAustralia review*, p. 33.
612 Wilson Cook, *EnergyAustralia review*, p. 33.
613 Wilson Cook, *EnergyAustralia review*, p. 33.

AER considerations

The AER does not accept EnergyAustralia's suggestion that it did not examine Wilson Cook's recommendation in relation to the escalation of asset management and project management costs. The AER's consideration and assessment of Wilson Cook's advice is set out in section P.4.5 of the draft decision.

The AER agrees with Wilson Cook's view that EnergyAustralia has not made a convincing case of the link between asset management and project management costs and capex. For example, Wilson Cook's suggestion that growth in maintenance planning is more likely to align with growth in the total level of assets rather than growth in capex, as proposed by EnergyAustralia, seems reasonable.

Having considered the material put forward, the AER accepts Wilson Cook's advice to adjust EnergyAustralia's escalation of asset management and project management costs.

For the reasons discussed and as a result of the AER's analysis of EnergyAustralia's revised regulatory proposal, the AER considers that reducing EnergyAustralia's opex for the escalation of asset management and project management costs as recommended by Wilson Cook results in expenditure that reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors. Following a request from the AER, EnergyAustralia advised that the AER's conclusion results in a reduction of $13 million ($2008–09) to its forecast opex.

8.5.2.4 Benchmarking of controllable opex

AER draft decision

In the draft decision, the AER accepted Wilson Cook's recommendations to reduce EnergyAustralia's proposed controllable opex based on a bottom up assessment of EnergyAustralia's opex requirements.[614] In making its recommendation, Wilson Cook indicated that its top down opex forecasts were 3 per cent lower than the adjusted bottom up level over the next regulatory control period.[615] Wilson Cook suggested that since its benchmarking analysis indicated that EnergyAustralia was operating at or slightly above the industry norm, the top down calculation confirms that the adjusted bottom up level of opex is not unreasonable.[616]

Revised regulatory proposal

EnergyAustralia criticised Wilson Cook's top down benchmarking analysis.[617] In particular, EnergyAustralia expressed concerns over the inherent limitations of benchmarking and stated that Wilson Cook's cost scale variable analysis contained errors relating to data, reasoning and methodology and had been poorly applied in the context of this review.

614 AER, *Draft decision*, p. 175.

615 Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 2 – EnergyAustralia*, p. 61.

616 Wilson Cook, *Volume 2*, p. 61.

617 EnergyAustralia, *Revised regulatory proposal*, p. 79.

EnergyAustralia claimed that Huegin's analysis demonstrates that Wilson Cook's benchmarking analysis should not be given any weight by the AER in determining whether proposed step change expenditure is prudent and efficient.[618]

Submissions

The EMRF suggested that while Wilson Cook's analysis of base year opex has some limitations, it shows that the NSW DNSPs' opex in the base year of the current regulatory control period is significantly higher than benchmark levels.[619] The EMRF also suggested the AER has not analysed in detail whether the base year benchmarks for opex reflect best practice levels.[620]

The EUAA suggested that operating costs appear to lack any substantial benchmarking.[621]

Consultant review

In response to criticisms of its benchmarking analysis, Wilson Cook undertook a completely new benchmarking analysis. This involved using data from its original analysis undertaken in 2008, corrected for certain errors.[622] Wilson Cook carried out a multiple regression analysis to determine the correlations that exist between opex and some or all of various parameters, including customer numbers, line length, energy throughput and maximum demand. Wilson Cook analysed linear and log relationships to determine the choice of parameters and relationship that best predicted opex. Predominantly rural entities were excluded, based on the findings of the multiple regression analysis. Based on its new analysis, Wilson Cook has applied a completely different formula as the best predictor of opex. Wilson Cook calculated confidence limits and added these to the analysis to add to the robustness of its findings.[623]

Wilson Cook stated that its new benchmarking addresses the methodological errors of its original method.[624] Wilson Cook noted that the new method produces results not materially different from those of the simple method used in the original analysis.[625] Specifically, Wilson Cook concluded that, based on its new benchmarking analysis, the top down approach suggests that EnergyAustralia's opex requirement for the next regulatory control period is \$2669 million[626] (which is 5 per cent higher than Wilson Cook's original top down forecast of \$2540 million).

Wilson Cook noted that the conclusions drawn from its benchmarking analysis in relation to EnergyAustralia's total controllable opex are limited to tests of reasonableness of the bottom up analysis.[627] Wilson Cook's bottom up estimate of EnergyAustralia's opex requirement for the next regulatory control period is \$2740 million (based on Wilson Cook's revised adjustments for opex step changes and escalation of maintenance costs

618 EnergyAustralia, *Revised regulatory proposal*, p. 81.
619 EMRF, p. 42.
620 EMRF, p. 4.
621 EUAA, p. 14.
622 Consisting of a correction to ETSA's opex and a minor modification in EnergyAustralia's opex (comprising the removal of \$10 million of storm-related costs in the base year). These corrections do not materially affect the analysis of EnergyAustralia's position.
623 Wilson Cook, *EnergyAustralia review*, p. 5.
624 Wilson Cook, *EnergyAustralia review*, p. 5.
625 Wilson Cook, *EnergyAustralia review*, p. 6.
626 Wilson Cook, *EnergyAustralia review*, p. 35.
627 Wilson Cook, *EnergyAustralia review*, p. 6.

and other operating costs). Wilson Cook noted that its revised benchmarking estimate is only 2.6 per cent below its revised bottom up estimate, compared to 3.5 per cent below in its original analysis. Based on these results, Wilson Cook stated that the benchmarking analysis suggests that the bottom up analysis is not unreasonable. On this basis, Wilson Cook recommended that EnergyAustralia's forecast opex for the next regulatory control period should be adjusted to reflect Wilson Cook's bottom up estimate.[628]

AER considerations

In response to the concerns noted by the EMRF and the EUAA regarding appropriate benchmarking, the AER notes that Wilson Cook's review included benchmarking assessments of the proposed efficient base year opex for each DNSP and of the forecast movements in opex from the efficient base year. Wilson Cook's rationale for this approach was that while each individual project or program may be justified when considered in isolation, it was still necessary that the aggregate opex projection be reasonable. Wilson Cook considered that the aggregation of estimates for individual projects and program without adequate consideration of their impact in total, or of cost savings in other parts of the business generally, does not lead to an efficient level of expenditure.[629]

The AER acknowledges that some valid issues were raised by EnergyAustralia in relation to Wilson Cook's benchmarking analysis, particularly regarding the manner in which the composite scale variable approach was applied. However, the AER considers that Wilson Cook has addressed the key criticisms of its original benchmarking approach in its revised benchmarking analysis. This is because the new benchmarking analysis does not rely in any way on the Ofgem composite scale variable analysis originally used by Wilson Cook. As the new analysis is based on a comparable peer group of mainly urban DNSPs and includes a number of statistical tests, the outcomes of the benchmarking appear to be robust but not materially different to those of the original analysis. As a result, the AER agrees with Wilson Cook that its new top down benchmarking analysis provides a useful test of the reasonableness of Wilson Cook's bottom up estimation of EnergyAustralia's opex allowance for the next regulatory control period.

For clarity, the AER notes that it has based its forecast of controllable opex for EnergyAustralia on a bottom up assessment of EnergyAustralia's proposed opex. In doing so, the AER has had regard for the top down benchmarking analysis of EnergyAustralia's opex, as contemplated under clause 6.5.6(e)(4) of the transitional chapter 6 rules. Overall, the AER is satisfied that the adjustments made to EnergyAustralia's forecast opex based on a bottom up assessment are supported by the top down analysis.

For the reasons discussed and as a result of the AER's analysis of EnergyAustralia's revised regulatory proposal and Wilson Cook's new top down benchmarking analysis, the AER considers that the adjustments made to EnergyAustralia's forecast opex, based on Wilson Cook's bottom up assessment, results in expenditure that reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

628 Wilson Cook, *EnergyAustralia review*, p. 35.
629 Wilson Cook, *Review of Proposed Expenditure of ACT & NSW Electricity DNSPs Volume 1*, p. 15.

8.5.3 Integral Energy

8.5.3.1 Changes to defined benefit superannuation costs

AER draft decision

The AER did not address the defined benefit superannuation costs for Integral Energy in the draft decision.

Revised regulatory proposal

Integral Energy stated that its regulatory proposal, provided to the AER on 2 June 2008, included a specific adjustment to its opex forecast of approximately $12 million per year (approximately $68 million ($2008–09) over the next regulatory control period) to recognise reductions in the provision for defined benefit superannuation obligations arising from the growth in superannuation portfolios expected at the time.[630] It stated that the previous assumptions of steady annual growth in superannuation portfolios implicit in Integral Energy's original regulatory proposal are no longer valid for the next regulatory control period.[631]

Integral Energy stated that given the reductions in the value of superannuation portfolios and the uncertainty regarding future performance of superannuation funds over the next regulatory control period, it removed from its revised regulatory proposal the annual reductions in the provisions for superannuation obligations (what it refers to as the forecast 'fair value' adjustments) included in its regulatory proposal.[632]

Submissions

Integral Energy provided a submission to the AER in which it addressed the impact of the global financial crisis on its regulatory proposal and revised regulatory proposal.[633] Integral Energy noted that the AER has recognised the existence of the global financial crisis and that its superannuation liabilities are impacted by the performance of the superannuation fund.[634] It considered that its submission is a suitable forum to address the impact of the global financial crisis on its forecast opex as outlined in its regulatory and revised regulatory proposal.

In its submission, Integral Energy provided a confidential actuarial assessment of its superannuation funding requirements for the six month period ending 31 December 2008 which highlighted a funding shortfall for that period. It noted that when combined with its 'fair market adjustment' included in its regulatory proposal, Integral Energy will require an opex allowance materially higher than that forecast in its regulatory proposal submitted in June 2008.[635]

AER considerations

In its revised regulatory proposal, Integral Energy provided updated information relating to its defined benefit superannuation obligations. This updated information includes revisions resulting from the change in the economic outlook for the Australian economy

[630] Integral Energy, *Revised regulatory proposal*, p. 38.
[631] Integral Energy, *Revised regulatory proposal*, p. 38.
[632] Integral Energy, *Revised regulatory proposal*, pp. 38–39.
[633] Integral Energy, *Submission to the AER*, pp. 6–8.
[634] Integral Energy, *Submission to the AER*, p. 6.
[635] Integral Energy, *Submission to the AER*, pp. 7–8.

since mid–2008 as reflected in official forecasts by Treasury.[636] The rapid change in the economic outlook is closely linked to the global financial crisis which manifest 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.[637] Given this extraordinary change in circumstances within the economic environment, the AER has decided to consider the updated information relating to defined benefit superannuation obligations in making its final decision.

The AER notes that Integral Energy did not explicitly address the reduction in its provisions for defined benefit superannuation obligations in its regulatory proposal though it has advised the AER that the adjustments were made prior to submitting the proposal. The adjustments were in anticipation of continued growth in superannuation portfolios at the time it submitted its regulatory proposal. As noted above, the AER has decided to consider Integral Energy's updated information relating to defined benefit superannuation obligations in light of the rapid change in the economic environment and impact of the global financial crisis. The AER notes that the financial risk associated with defined benefit superannuation obligations lies with the employer rather than the employee and as such, the impact of the reduction in provisions in the current climate is borne by Integral Energy. Further, the AER notes that the impact on the superannuation provisions is beyond the control of Integral Energy. The AER therefore considers Integral Energy's proposed reversal of its adjustments to provisions for defined benefit superannuation obligations are, under the current circumstances, appropriate.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal and additional information, the AER is satisfied that Integral Energy's reversal of its adjustments to provisions for defined benefit superannuation obligations in its opex forecast reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors.

8.5.4 Cost escalators

8.5.4.1 Electricity, gas and water and general labour escalators

AER draft decision

In the draft decision, the AER engaged Econtech to provide advice on labour cost growth forecasts in NSW. 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 the NSW DNSPs' 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.[638]

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 DNSPs. The AER however, did not accept the general wage forecasts applied by the NSW DNSPs, 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

636 The Treasury, *Updated Economic and Fiscal Outlook*, February 2009.
637 International Monetary Fund, *World Economic Outlook*, October 2008.
638 AER, *Draft decision*, p. 537.

more appropriate as they took account of more recent data, and were based on a more reliable forecasting methodology and robust data source.[639]

Revised regulatory proposals

The NSW DNSPs did not accept the EGW and general labour escalators applied by the AER in its draft decision. The NSW DNSPs 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 and general wages growth were in financial year average terms, and not in June to June terms
- Enterprise Bargaining Agreement (EBA) rates 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.

CEG raised issues with the application of updated EGW and general labour escalators after the businesses had lodged their revised regulatory proposals. CEG considered that if the AER was to seek an update from Econtech for EGW and general labour cost growth rates, it would be described as re–doing a forecast, rather than updating a forecast in accordance with an agreed methodology.[640]

Submissions

The EUAA stated that, due to the worsening economic climate, wage cost pressures had fallen. The EUAA noted the Reserve Bank of Australia (RBA) had revised its wage price index from 4 per cent in 2008–09 to 3.5 per cent in 2009–10. Further the RBA expects the wage price index to remain static at 4 per cent for 2010–11 to 2011–12.[641]

The EMRF noted that due to current economic climate conditions, wage cost escalation data is out of date and labour cost escalation is not reflective of current expectations. It also noted that EGW and general wages should be discounted by long–term levels of inflation.[642]

Origin Energy noted concerns with the predicted increases in labour costs based on earlier periods which suggests the data relied upon regarding labour cost growth is ceasing to reflect actual changes. Further, Origin Energy noted economic data pointed to stable labour costs in 2009–10 compared with the 2006–07 and 2007–08 financial years.[643]

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639 Econtech, *Updated labour costs growth forecasts*, 25 March 2009, p. 38 and AER, *Draft decision*, p. 541.

640 The NSW DNSPs, based on advice from CEG considered that should the AER re-commission Econtech to provide updated forecasts, the AER should consult with the businesses. CEG, *Escalators affecting expenditure forecasts, A report for NSW and Tasmanian electricity businesses*, p. 13.

641 EUAA, p. 18.

642 EMRF, pp. 14–15.

643 Origin Energy, p. 5.

Consultant review

Econtech

The AER engaged Econtech to provide an update on its wage forecasts for the EGW sector in NSW. 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 in NSW for the next regulatory control period is shown in table 8.10 and outlined in further detail in appendix L of this final decision.

Table 8.10: Econtech's real EGW labour escalation rates for NSW (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
NSW	1.3	–0.7	3.3	3.6	2.4	1.7	0.6

Source: Econtech, *Updated labour cost growth forecasts*, p. 28.

Econtech also provided an update on general wage forecasts for all–industries in NSW. Econtech's updated general wage forecasts are shown in table 8.11.

Table 8.11: Econtech's real general labour escalation rates for NSW (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
General labour	0.9	–1.6	0.7	1.3	0.4	0.1	–0.6

Source: Econtech, *Updated labour cost growth forecasts*, p. 28.

AER considerations

Updated labour cost escalators

The details of the AER's assessment of the labour cost growth forecasts proposed by the NSW DNSPs are set out in appendix L 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.[644] The AER considers that the updated forecasts take account of the current economic slowdown.

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 the NSW DNSPs' labour cost 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.

[644] New forecasts incorporate data published by the ABS, including Average Weekly Earnings (released 26 February 2009) and National Accounts (released 9 March 2009).

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 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 the NSW DNSPs, based on advice received from CEG, accepted the use of Econtech's forecasts in the draft decision, subject to the AER rectifying the specified timing issues.[645] The AER further notes the NSW DNSPs' concerns with Econtech updating its forecasts after their revised regulatory proposals have been submitted. To ensure a robust and transparent process on the updating of labour wage growth forecasts, the AER engaged in a briefing with the NSW DNSPs, 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.

For this final decision, the AER has adopted Econtech's updated 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 NSW for 2008–09 and the next regulatory control period. Actual wage data, however, was available for 2007–08 and therefore, the AER has applied actual wage increases provided for under the NSW DNSPs workplace awards or enterprise bargaining agreements for that year, which have also been remodelled with respect to specified timing issues.

The EGW labour cost growth forecasts the AER will apply to the NSW DNSPs' opex for the next regulatory control period are shown in table 8.12.

Table 8.12: AER conclusion on NSW real EBA/EGW labour escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Country Energy	–0.17	–0.38	2.54	3.60	2.40	1.70	0.60
EnergyAustralia	1.46	0.20	3.35	3.60	2.40	1.70	0.60
Integral Energy	–	1.38	3.35	3.60	2.40	1.70	0.60

Note: Rates vary in 2007–08 to 2009–10 for the NSW DNSPs due to the different base periods adopted in their regulatory proposals.

For this final decision, the AER has also adopted Econtech's updated NSW general labour cost escalators for 2007–08 to 2008–09 and the next regulatory control period. The general labour cost forecasts the AER will apply to the NSW DNSPs are shown in table 8.13.

645 CEG, *Escalators affecting expenditure forecasts*, pp. 7–12.

Table 8.13: AER conclusion on NSW real general labour escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Country Energy	0.90	–1.60	0.70	1.30	0.40	0.10	–0.60
EnergyAustralia	1.01	–1.60	0.70	1.30	0.40	0.10	–0.60
Integral Energy	–	–1.80	0.70	1.30	0.40	0.10	–0.60

Note: Rates vary in 2007–08 to 2008–09 for the NSW DNSPs due to the different base periods adopted in their regulatory proposals.

Application of updated labour cost escalators

In the draft decision, the AER accepted that the application of labour cost escalators (EGW wages and/or general labour) by EnergyAustralia and Integral Energy to their forecast opex was a reasonable approach to forecasting opex costs. Following a request from the AER to apply the updated Econtech EGW and general wage growth forecasts, EnergyAustralia and Integral Energy advised that the AER's conclusions result in a reduction of $122 million[646] and an increase of $9.8 million[647] ($2008–09) to their respective opex forecasts.

In the draft decision, the AER required Country Energy to apply the general labour escalator, rather than the EGW wage escalator, to the labour component of its vegetation management contracts.[648] The AER notes Country Energy's revised regulatory proposal incorporated this requirement.[649] Following a request from the AER, Country Energy advised that the AER's conclusion (applying updated EGW and general labour cost escalators) results in a reduction of $35 million ($2008–09) to its forecast opex.[650]

Conclusion

As a result of the AER's analysis of the revised regulatory proposals, the AER is satisfied that the application of updated EGW and general labour cost escalators for NSW (as set out in tables 8.12 and 8.13), within the NSW DNSPs' opex models, results in forecast opex which reasonably reflects the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors.

8.5.4.2 Non–labour costs

AER draft decision

In the draft decision, the AER did not accept the application of Country Energy's escalator of crude oil to approximately 4 per cent of its non–labour opex and instead required the CPI to be applied.[651]

646 EnergyAustralia, *Response to AER*, 16 April 2009.
647 Integral Energy, *Response to AER*, 16 April 2009.
648 AER, *Draft decision*, p. 181.
649 Country Energy, *Revised regulatory proposal*, p. 32.
650 Country Energy, *Response to AER*, 16 April 2009.
651 EnergyAustralia and Integral Energy applied the CPI to escalate the non–labour component of their opex proposals.

The AER noted Country Energy did not provide any explanation regarding why it was appropriate to deviate from price movements adequately captured by CPI and apply the crude oil escalator to its opex forecasts.[652]

Revised regulatory proposal

Country Energy did not accept the draft decision, however, this was not discussed in its revised regulatory proposal. The AER sought clarification from Country Energy on how it had applied non–labour escalators to opex in the revised regulatory proposal.[653] Country Energy advised that it has maintained the application of the crude oil escalator for fuel used in plant items. Country Energy believed this escalator is equally applicable to plant opex as it is to plant capex.[654]

AER considerations

The AER has reviewed the additional information provided by Country Energy.

The AER is not satisfied that the additional information submitted by Country Energy provides sufficient reasons to support deviating from applying the CPI as an escalator for non–labour opex, given the mix of materials used in opex is generally miscellaneous in nature. The AER maintains its draft decision that the price movements of fuel used in plant related opex would be adequately captured by the CPI. The movements in the price of oil would be taken into account with changes in CPI—that is, the price of oil would impact on components of the CPI and thus be reflected in the CPI.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal and additional information, the AER is not satisfied that Country Energy's approach in applying a crude oil escalator to its opex results in forecast expenditures which reasonably reflect the opex criteria, including the opex objectives. In coming to this view, the AER has had regard to the opex factors. Following a request from the AER, Country Energy advised that the AER's conclusion results in a reduction of $10 million ($2008–09) to its forecast opex.[655]

8.5.5 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 DNSP should be provided an allowance.[656]

AER draft decision

In the draft decision, the AER did not accept the NSW DNSPs' proposals to include, in its opex forecasts, benchmark allowances for debt raising costs equal to 0.155 per cent

652 AER, *Draft decision*, p. 541.
653 Country Energy, *Request for information*, 10 February 2009.
654 Country Energy, *Request for information*, 10 February 2009.
655 Country Energy, *Response to AER*, 16 April 2009.
656 AER, *Decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 14 June 2007, pp. 94–97; AER, *Final decision, SP AusNet transmission determination 2008–09 to 2013–14*, January 2008, pp. 148–150 and AER, *Final decision, ElectraNet transmission determination 2008–09 to 2013–14*, 11 April 2008, pp. 84–85.

(15.5 basis points) of the benchmark debt share (60 per cent) of each DNSP's opening regulatory asset base (RAB) in each year of the next regulatory control period.[657]

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 efficient costs under–compensated regulated network service providers (NSPs).[658]

Accordingly, the AER maintained its approach of providing benchmark debt raising costs in accordance with the 2004 Allen Consulting Group (ACG) methodology[659] as applied in previous transmission determinations.[660] 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 the NSW DNSPs, the AER approved the debt raising cost allowances for the next regulatory control period as set out in table 8.14.[661]

Table 8.14: AER draft decision on debt raising costs for the NSW DNSPs ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	2.0	2.3	2.5	2.8	3.0	12.6
EnergyAustralia	3.8	4.5	5.1	5.8	6.4	25.5
Integral Energy	1.7	1.9	2.1	2.3	2.5	10.6

Source: AER, *Draft decision*, p. 189.

Revised regulatory proposals

None of the NSW DNSPs accepted the draft decision on benchmark debt raising costs.

Country Energy and Integral Energy restated their views on the legitimacy of indirect debt raising costs, and submitted a report by the Competition Economists Group (CEG), in support of their proposed debt raising cost allowance.[662]

EnergyAustralia's revised regulatory proposal also referred to CEG's report, and stated its following positions on this matter:

- the AER does not have reasons to reject US data on debt raising costs

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657 AER, *Draft decision*, pp. 186–189.
658 AER, *Draft decision*, p. 187.
659 ACG, *Debt and equity raising transaction costs: final report to the ACCC*, December 2004.
660 AER, *Decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–12*, 14 June 2007, pp. 94–97; AER, *Final decision, SP AusNet transmission determination 2008–09 to 2013–14*, January 2008, pp. 148–150; AER, *Final decision, ElectraNet transmission determination 2008–09 to 2013–14*, 11 April 2008, pp. 84–85.
661 AER, *Draft decision*, pp. 186–189.
662 Country Energy, *Revised regulatory proposal*, p. 32; Integral Energy, *Revised regulatory proposal*, p. 43.

- the AER's argument that a regulated firm would have among the lowest cost of debt raising is inconsistent with the NER
- underpricing is not solely a function of credit rating, but ensures the success of raising capital
- indirect costs meet the opex criteria in the NER and are efficient costs that a prudent operator in the circumstances of the NSW DNSPs would incur.[663]

EnergyAustralia also provided an additional consultant report by Tony Carlton to support its positions on this matter.[664]

The NSW DNSPs' revised regulatory proposals for debt raising cost allowances are set out in table 8.15.

Table 8.15: NSW DNSPs' revised regulatory proposals on debt raising cost allowances ($m, $2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	4.0	4.5	5.0	5.5	6.1	25.0
EnergyAustralia	7.6	9.0	10.1	11.4	12.6	50.8
Integral Energy	3.5	3.9	4.3	4.6	4.8	21.1

Sources: Country Energy, *Revised regulatory p*roposal, p. 32; EnergyAustralia, *Revised regulatory proposal PTRM confidential* and Integral Energy, *Revised regulatory proposal*, p. 43.

Note: Totals may not add up due to rounding.

Submissions

EnergyAustralia noted that all the NSPs proposed the same allowance for debt raising costs (15.5 bppa on the debt component of RAB) and that this was the same position stated in their respective regulatory proposals.[665] Given the evident consistency across proposals, EnergyAustralia 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 the NSW DNSPs for the next regulatory control period.

EnergyAustralia's further submission on the draft decision attached the Joint Industry Association's (JIA) submission to the AER's WACC review.[666] The JIA stated that indirect and direct debt raising costs were direct substitutes (in line with the CEG report), and that the AER needed to adjust its previous methodology upwards (to at least 19.5 bppa) to provide an allowance for indirect costs.[667] Additionally, JIA questioned the appropriateness of the direct cost proxy used in the ACG methodology and argued that

663 EnergyAustralia, *Revised regulatory proposal*, pp. 105–107.

664 Carlton, *Indirect costs of equity and debt raising: report prepared for EnergyAustralia*, January 2009. Provided as attachment 3P to EnergyAustralia's revised regulatory proposal.

665 EnergyAustralia, *Submission other network service providers*, February 2009, p. 3.

666 EnergyAustralia, *Further submission*, 16 February 2009, attachment V.

667 JIA, *Network Iindustry Submission: Debt and Equity Raising Costs,* 11 November 2008, pp. 20–21.

each NSP should specify the timing and size of each debt issue in their regulatory proposal rather than accepting allowances based on average AER assessments.[668]

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 regulatory proposals and revised regulatory proposals submitted by the NSW DNSPs, and all relevant accompanying consultant reports.[669]

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.[670]

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 this to be the case), then it is my view that, underpricing should not be allowed as a cost of raising debt capital.[671]

On the direct costs of raising debt capital, Associate Professor Handley noted the debate regarding the measurement of direct costs, amortisation and inflation. Where relevant, detailed comments drawn from his review are included in the AER considerations, provided in appendix N of this final decision.

AER considerations

The AER's detailed considerations of the NSW DNSP's proposed debt raising costs are presented in appendix N of this final decision. The AER notes that the consultancy reports submitted by the NSW DNSPs on these matters are also applicable to the AER's considerations concerning ActewAGL's regulatory proposal and TransGrid's and Transend's revenue proposals. The AER considers that its approach should be consistently applied across each of these businesses. Accordingly, appendix N sets out the AER considerations of all material submitted as part of the current regulatory processes, and is applicable to the AER's final decisions for the ACT and NSW DNSPs, TransGrid, and Transend.

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,[672] the AER expects that such costs would already be taken into

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668 JIA, pp. 20–21.

669 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.

670 Handley, pp. 15–16.

671 Handley, p. 17.

672 The AER considers that there is no reliable empirical evidence that indirect debt raising costs exist.

account through estimates of the cost of debt. This view is supported by Associate Professor Handley.[673]

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.[674] 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 NSPs and their consultants. Among other reasons, this is because the ACG approach is based on market observations of Australian firms raising capital, rather than foreign firms in foreign markets.

Table 8.16 shows the updated build up of debt raising costs and the total benchmark for various bond issues, based on the ACG's methodology.

Table 8.16: Benchmark debt raising costs for corporate bond issues (bppa)

Fee	Explanation/source	1 issue	11 issues	13 issues	25 issues
Amount raised	Multiples of median bond issue size	$200m	$2200m	$2600m	$5000m
Gross underwriting fees	Bloomberg for Australian internal issues, term adjusted	6.0	6.0	6.0	6.0
Legal and roadshow	$75k–$100k: industry sources	1.0	1.0	1.0	1.0
Company credit rating	$30k–$50k (once off): S&P ratings	2.5	0.2	0.2	0.1
Issue credit rating	3.5 (2.5) basis points up front: S&P ratings	0.7	0.7	0.7	0.7
Registry fees	$3k/issue: Osborne Associates	0.2	0.2	0.2	0.2
Paying fees[a]	$1/$1m quarterly: Osborne Associates	0.0	0.0	0.0	0.0
Total	Basis points per annum	10.4	8.1	8.1	8.0

Source: AER updated figures based on the methodology in ACG, *Debt and equity raising transaction costs: final report to the ACCC*, December 2004.
(a) Rounded to 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.[675]

Based on the ACG methodology, Country Energy will require around 13 bond issues over the next regulatory control period. As such, the AER considers that an allowance of 8.1 bppa for debt raising costs is a reasonable benchmark for Country Energy. Using the

673 Handley, pp. 14–17.
674 AER, *Draft decision*, pp. 186–189.
675 AER, *Draft decision*, p. 187.

post–tax revenue model (PTRM), this benchmark is multiplied by the debt component of Country Energy's opening RAB to provide an average allowance of $2.6 million per annum ($2008–09).

Based on the ACG methodology, EnergyAustralia will require around 25 bond issues over the next regulatory control period. As such, the AER considers that an allowance of 8.0 bppa for debt raising costs is a reasonable benchmark for EnergyAustralia. This benchmark is multiplied by the debt component of EnergyAustralia's opening RAB to provide an average allowance of $5.0 million per annum ($2008–09).

Based on the ACG methodology, Integral Energy will require around 11 bond issues over the next regulatory control period. As such, the AER considers that an allowance of 8.1 bppa for debt raising costs is a reasonable benchmark for Integral Energy. This benchmark is multiplied by the debt component of Integral Energy's opening RAB to provide an average allowance of $2.1 million per annum ($2008–09).

The AER's conclusion on benchmark debt raising costs for the NSW DNSPs over the next regulatory control period is set out in table 8.17.

Table 8.17: AER conclusion on benchmark debt raising costs ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	2.1	2.3	2.6	2.8	3.1	12.9
EnergyAustralia	3.9	4.5	5.0	5.6	6.2	25.2
Integral Energy	1.8	1.9	2.1	2.3	2.4	10.5

For the reasons discussed and as a result of the AER's analysis of the NSW DNSPs' revised regulatory proposals and additional information, the AER is not satisfied that the NSW DNSPs' proposed debt raising cost allowances reasonably reflect 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 allowances set out in table 8.17 represent the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives in the next regulatory control period.

8.5.6 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 little or no ongoing costs over the life of the equity. Whilst the size of the equity a firm will raise is typically at its inception, there may be points in the life of a firm—for example, during capital expansions—where it chooses additional external equity funding (instead of debt or internal funding) as a source of equity capital, and accordingly may incur equity raising costs.

The AER has accepted that equity raising costs are a legitimate cost for a benchmark efficient firm only where external equity funding is the least–cost option available.[676] A

[676] AER, *Decision, Powerlink Queensland transmission network revenue cap 2007–08 to 2011–2012*, 14 June 2007, p. 100; AER, *Final decision, SP AusNet transmission determination 2008–09 to 2013–*

DNSP should only be provided an allowance for equity raising costs where cheaper sources of funding—for instance, 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 rejected the NSW DNSPs' proposals for opex allowances for equity raising costs equal to 7.6 per cent of the required equity, based on the capex allowance.[677] The AER was not convinced by the NSW DNSPs' and their consultant's arguments that indirect costs of raising equity need to be included in the allowance, and applied the ACG (2004) methodology for calculation of direct equity raising costs only.[678]

In reviewing the DNSPs' regulatory proposals and submissions, the AER decided to amend its benchmark cash flow analysis to rely on the assumption of a given dividend payout ratio, rather than a given dividend yield.[679]

While the NSW DNSPs proposed to include equity raising costs under a perpetuity stream as part of their forecast opex allowances, the AER considered that there would be merit in treating the equity raising cost allowances as a part of the DNSPs' RAB—that is, to capitalise the allowances.[680]

The AER decided that the total amount of benchmark equity raising costs associated with the NSW DNSPs' capex for the next regulatory control period should be:[681]

- $4.2 million ($2008–09) for Country Energy
- $36 million ($2008–09) for EnergyAustralia
- $0.4 million ($2008–09) for Integral Energy.

Revised regulatory proposals

None of the NSW DNSPs accepted the draft decision on benchmark equity raising costs for the next regulatory control period. However, the NSW DNSPs did accept the AER's decision to capitalise the allowances to improve transparency and simplify the regulatory reset process.[682]

Country Energy's revised regulatory proposal stated that it had engaged CEG to review the draft decision on equity raising costs. Based on CEG's recommendations, Country Energy maintained the position in its regulatory proposal on equity raising costs.[683]

EnergyAustralia made the following arguments in its revised regulatory proposal:

14, January 2008, p. 144; AER, *Final decision, ElectraNet transmission determination 2008–09 to 2013–14*, 11 April 2008, p. 88.

677 AER, *Draft decision*, p. 192.

678 AER, *Draft decision*, pp. 190–192.

679 AER, *Draft decision*, p. 195.

680 AER, *Draft decision*, p. 197.

681 AER, *Draft decision*, p. 197.

682 Country Energy, *Revised regulatory proposal*, p. 46; EnergyAustralia, *Revised regulatory proposal*, p. 42; Integral Energy, *Revised regulatory proposal*, pp.–44-47.

683 Country Energy, *Revised regulatory proposal*, p. 46.

- empirical data from the US shows that rights issues are not the most common form of equity raising, but rather placements have been used by utilities to raise more equity[684]
- with placements as the predominant form of raising equity, there is a wealth transfer from existing equity shareholders to new shareholders, and a dilution of the value of existing shares. A non-renounceable rights issue is akin to placing a 'gun to the head' of existing shareholders who are forced to subscribe to the issue. Also, when rights are renounceable, shareholders can face the transaction costs of selling their rights[685]
- recognising underpricing does not imply a rejection of the capital asset pricing model (CAPM), as the CAPM does not attempt to recognise the transaction costs in issuing new securities[686]
- the draft decision failed to recognise that an underwriting contract results in a regulated firm giving the underwriter a call option[687]
- underpricing is an important element of an efficient capital raising strategy, and is a cost that meets the capex and opex criteria in the NER[688]
- the draft decision cash flow modelling equates to a dividend yield significantly below the return on equity that an investor would expect, and that the AER should be consistent in its decision regarding dividend payout policy and the economic outcomes and timing assumptions of the PTRM[689]
- the use of internally generated cash flows as equity is not costless.[690]

Integral Energy noted the main arguments raised in the CEG report, and raised a number of the issues which were also noted by EnergyAustralia, listed above.[691] In addition, Integral Energy raised the following concerns:

- the AER is mistaken in assuming that an efficiently run business will only make capital financing decisions based on which option minimises direct transactions costs. Instead, an efficient firm will consider all costs, including indirect costs, that its decision places on existing shareholders[692]
- the AER's cash flow modelling treats all net cash flows as being 100 per cent equity, despite all assets being subject to the gearing assumptions specified in the NER. Integral Energy also pointed out that retained cash should not be mistaken with economic profits, but rather is the result of exchanging non–current assets for current assets.[693]

Submissions

EnergyAustralia noted that all the NSPs were proposing the same allowance for equity raising costs (7.6 per cent of the amount raised) and that this was the same position as

684 EnergyAustralia, *Revised regulatory proposal*, p. 44.
685 EnergyAustralia, *Revised regulatory proposal*, p. 45.
686 EnergyAustralia, *Revised regulatory proposal*, p. 46.
687 EnergyAustralia, *Revised regulatory proposal*, pp. 46–47.
688 EnergyAustralia, *Revised regulatory proposal*, p. 47.
689 EnergyAustralia, *Revised regulatory proposal*, pp. 47–48.
690 EnergyAustralia, *Revised regulatory proposal*, p. 48.
691 Integral Energy, *Revised regulatory proposal*, pp. 44–47.
692 Integral Energy, *Revised regulatory proposal*, p. 45.
693 Integral Energy, *Revised regulatory proposal*, p. 46.

advocated in their respective regulatory proposals.[694] Given the evident consistency across proposals, EnergyAustralia 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 determinations for the NSW DNSPs for the next regulatory control period.

EnergyAustralia's further submission on the draft decision attached the JIA submission to the AER's WACC review.[695] The JIA stated that indirect and direct equity raising costs were direct substitutes (in line with the CEG report), and that the AER needed to adjust its previous methodology to provide an allowance for indirect equity raising costs.[696] JIA stated that using internal cash flows to fund new capex is not costless, and that infrastructure businesses must satisfy their investors by providing a high dividend yield (8 per cent) each year.[697]

Consultant review

Associate Professor Handley was engaged by the AER to review the submitted material on this issue, including the regulatory proposals and revised regulatory proposals submitted by the NSW DNSPs, 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.[698] 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.[699]

Associate Professor Handley also 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.

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 per cent and 3 per cent of the amount raised.[700]

Finally, Associate Professor Handley considered the benchmark cash flow modelling applied to determine the equity requirement. He noted many of the assumptions were

694 EnergyAustralia, *Submission other network service providers*, p. 3.
695 JIA.
696 JIA, p. 17.
697 JIA, pp. 11–17.
698 Handley, pp. 7–8.
699 Handley, p. 11.
700 Handley, p. 27.

‘arbitrary in the sense that they are simply inputs into the modelling process,’[701] but stated:

> The key issue is to ensure that any assumptions made here are consistent with the overall regulatory framework.[702]

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.[703]

AER considerations

The AER’s detailed considerations of the NSW DNSPs’ proposed equity raising costs are presented in appendix N, of this final decision. The AER notes that the consultancy reports submitted by the NSW DNSPs on these matters are also applicable to the AER’s considerations concerning the regulatory proposals of ActewAGL and revenue proposals of TransGrid and Transend. The AER considers that the approach applied should be consistent across each of these businesses. Accordingly, appendix N sets out the AER’s considerations of all material submitted as part of the current regulatory processes and is applicable to the AER’s final decisions for the ACT and NSW DNSPs, TransGrid and Transend.

In summary, the AER considers that the proposed allowance for indirect equity raising costs is inconsistent with the regulatory framework. To the extent that indirect equity raising costs exist, they can reasonably be expected to be included in the existing return on equity allowance which is based on the expected 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 Associate Professor Handley.[704]

In relation to direct equity raising costs, the AER considers that the benchmark cost applied in the draft decision remains the best estimate of costs applicable to the benchmark NSP. The benchmark rate applied in the draft decision was based on application of the ACG methodology, which used recent domestic market data. The AER also notes that this benchmark equity raising cost is consistent with the range recommended by Associate Professor Handley.[705]

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, the NSW DNSPs submitted that the draft decision understated the appropriate level of dividends.[706] This resulted in a higher level of retained earnings, which in turn, resulted in a lower external equity requirement. The NSW DNSPs were concerned that the benchmark level

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701 Handley, pp. 31–32.
702 Handley, p. 32.
703 Handley, pp. 31–34.
704 Handley, p. 11.
705 Handley, p. 27.
706 Country Energy, *Revised regulatory proposal*, Appendix C, section 3.2; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46.

of dividends was insufficient to enable them to realise the value of imputation credits assumed in the PTRM.[707] The NSW DNSPs also sought an allowance for the cost of retained earnings.[708] 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 benchmark cash flow analysis (from the approach applied in the 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 (based on available evidence)
- a benchmark cost of 1 per cent has been applied to equity raised through dividend reinvestment plan
- an error in the presentation of the capex funding requirement has been corrected (in the draft decision the capex funding requirement inappropriately included a 'grossed up' WACC 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.

The AER's conclusions on benchmark equity raising costs for the NSW DNSPs over the next regulatory control period are set out in table 8.18.

[707] Carlton, p. 26; Country Energy, *Revised regulatory proposal*, Appendix C, p. 29; Integral Energy, *Revised regulatory proposal*, Appendix F, p. 29.
[708] Country Energy, *Revised regulatory proposal*, Appendix C, pp. 29–30; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 45.

Table 8.18: AER conclusions on benchmark equity raising costs ($m, nominal)

Cash flow analysis	Country Energy	EnergyAustralia	Integral Energy	Notes
Dividends	542.3	837.9	465.1	Set to distribute imputation credits assumed in the PTRM
Dividends reinvested	162.7	251.4	139.5	30% of dividends paid
Cost of dividend reinvestment plans	1.6	2.5	1.4	Dividends reinvested multiplied by benchmark cost (1%)
Capex funding requirement	4026.9	8229.2	2838.3	This is not the capex value that includes a half year WACC adjustment
Debt component	2031.4	4773.8	1412.6	Set to equal 60% of RAB increase (not capex)
Equity component	1995.5	3455.4	1425.7	Residual of capex funding requirement and debt component
Retained cash flows available for reinvestment	1414.2	2056.9	1120.0	Includes dividends reinvested
External equity requirement	581.3	1398.5	305.7	Equal to equity component less retained cash flows
External equity raising cost	16.0	38.5	8.4	External equity requirement multiplied by benchmark direct cost (2.75%)
Total equity raising cost ($2008–09)	16.8	38.0	9.4	Sum of dividend reinvestment plan cost and external equity raising cost

The AER notes that the NSW DNSPs accepted the AER draft decision on adding the allowance for benchmark equity raising costs to the RAB. As such, the AER maintains this approach and the amounts specified in table 8.18 will be amortised over the life of the NSW DNSPs' RAB for the purposes of providing the equity raising cost allowance associated with the forecast capex over the next regulatory control period.[709]

[709] For Country Energy a standard life of 44.7 years for amortisation purposes, consistent with Country Energy's weighted average asset life, has been assumed. For EnergyAustralia standard lives of 47.4 and 45.7 years for amortisation purposes, consistent with EnergyAustralia's weighted average asset lives for its distribution and transmission assets respectively, have been assumed. For Integral Energy a standard life of 41 years for amortisation purposes, consistent with Integral Energy's weighted average asset life, has been assumed.

For the reasons discussed and as a result of the AER's analysis of the NSW DNSPs' revised regulatory proposals and additional information, the AER is not satisfied that the NSW DNSPs' proposed equity raising cost allowances reasonably reflect 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 equity raising cost allowances associated with the NSW DNSPs' capex forecasts, set out in table 8.18 represent the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives in the next regulatory control period.

8.5.7 Self insurance

AER draft decision

In the draft decision, the AER accepted the NSW DNSPs' proposed allowances for self insurance for the following risks:

- fraud risk
- insurers' credit risk
- counterparty credit risk
- key assets risk (except for third party claims)
- workers compensation.

However, the AER indicated that for other risks, it was not satisfied that the NSW DNSPs, based on advice from SAHA International Limited (SAHA), had provided robust analysis which supported the probability of an event occurring or the costs associated with the event, and therefore the calculation of the self insurance premium.[710] The AER considered that the NSW DNSPs' proposed self insurance allowances did not reflect the efficient costs that a prudent operators in the circumstances of the NSW DNSPs would require to achieve the opex objectives, or a realistic expectation of those costs, and made adjustments accordingly. The AER reduced Country Energy's self insurance allowance from \$20 million to \$15 million, EnergyAustralia's allowance from \$30 million to \$21 million, and Integral Energy's allowance from \$16 million to \$10 million (\$2008–09) for the next regulatory control period.[711]

Revised regulatory proposals

None of the NSW DNSPs accepted the reductions to the self insurance allowances determined by the AER and they jointly commissioned SAHA to respond to the draft decision.[712]

SAHA prepared a generic report in relation to self insurance costs for Country Energy, EnergyAustralia, Integral Energy, ActewAGL and TransGrid.[713] The SAHA report

[710] EnergyAustralia, *Regulatory proposal,* attachment 10.1, confidential; Integral Energy, *Regulatory proposal,* appendix O, confidential; Country Energy, *Regulatory proposal,* appendix D, confidential.
[711] AER, *Draft decision*, p. 184.
[712] SAHA, *Response to the AER's Draft Decision – Self Insurance*, 14 January 2009, confidential.
[713] Each of these businesses proposed self insurance allowances in their regulatory proposals and engaged SAHA to determine the original risk estimates and associated self insurance premiums. Since many of the issues raised in the AER's draft decisions in relation to self insurance are similar across these businesses, SAHA provided a single report in response.

provided comments regarding the AER's assessment of self insurance and a response to the AER's rejection of allowances for each of the businesses.

AER approach to assessing self insurance premiums

In response to the draft decision to not provide a self insurance allowance for specific risks the following comments were made by NSW DNSPs:

- EnergyAustralia stated the AER did not provide sufficient evidence to suggest that the assumptions underlying the SAHA model were incorrect.[714]
- Integral Energy questioned whether the AER had based its findings on an actuarial assessment.[715] EnergyAustralia considered that the AER was not in a position to make a decision on self insurance premiums without the assistance of experts.[716]
- EnergyAustralia stated that the AER has not provided reasons for estimating a value of zero for certain self insurance events as required by the NER.[717]
- EnergyAustralia noted that the fact that an event has not occurred to date was not a justifiable reason to assign zero probability of it occurring in the future and therefore not a valid reason to conclude that insuring against that event is not reasonable, prudent and efficient. In addition, EnergyAustralia provided examples of incidents that occurred since the AER published the draft decision to support its contention that the AER's application of a zero premium to these events on the basis of previous non–occurrence was inappropriate.[718]
- EnergyAustralia noted that the AER did not amend the values and methodologies that it expressed concerns about. Rather, it dismissed the proposed cost entirely. EnergyAustralia suggested that the resultant zero probability assumptions are intrinsically incorrect and should be rectified.[719]
- Country Energy suggested that the AER's draft decision implies that because a risk is not supported by historical data that the risk does not exist and as such Country Energy should not be compensated for the costs in the future.[720]

SAHA stated that the AER appears to have adopted a number of sub–criteria in assessing whether the self insurance premiums reasonably reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives.[721] SAHA suggested noted that these sub–criteria appear to include that a zero self insurance risk allowance will more reasonably reflect the efficient costs that a prudent operator would incur than SAHA's valuation when:[722]

- that the business has never borne a cost resulting from the risk
- the historical data supporting the derivation of that risk is deemed to be for a period that is not long enough

714 EnergyAustralia, *Revised regulatory proposal*, p. 104.
715 EnergyAustralia, *Revised regulatory proposal*, p. 104 and Integral Energy, *Revised regulatory proposal*, p. 41.
716 EnergyAustralia, *Revised regulatory proposal*, p. 104.
717 EnergyAustralia, *Revised regulatory proposal*, p. 104.
718 EnergyAustralia, *Further submission*, p. 10.
719 EnergyAustralia, *Further submission*, p. 11.
720 Country Energy, *Revised regulatory proposal*, p. 30.
721 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 3.
722 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 3.

- qualitative evidence has been used to support a risk quantification, even if this qualitative evidence is used in conjunction with quantitative evidence
- the quantification relies on data derived from similar events that have affected other electricity businesses.

Further, SAHA suggested that efficient estimates can be derived in the absence of a perfect historical data and that 'reasonable practitioners' adopt similar approaches to those used by SAHA in order to determine premiums in the absence of such data.[723] SAHA stated that these practitioners leverage off available information and use professional judgement to determine premiums.[724] SAHA also stated that its self insurance estimates were reviewed by an actuary.[725]

SAHA noted that the AER does not appear to question the validity of any of the risks presented.[726] Accordingly, SAHA suggested that if the AER maintains its position that the self insured quantifications for a number of the risks do not reasonably reflect the efficient costs associated with the risks, then the businesses should still be compensated in some way for bearing that risk, or alternatively, they must be allowed to adopt an alternative risk mitigation strategy.[727] SAHA stated that the AER should inform the DNSPs of the preferred method for mitigating these risks, or any adjustments that could be made to the proposed current quantification.[728]

Revised self insurance allowances

Based on SAHA's recommendations, the NSW DNSPs proposed that self insurance allowances be reinstated for a number of events. These events are identified in table 8.19.

723 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 20.
724 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 19.
725 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 21.
726 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 20.
727 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 24.
728 SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 25.

Table 8.19: NSW DNSPs' proposed self insurance costs for reinstatement

Type of risk	Country Energy	EnergyAustralia	Integral Energy
Terrorism	✔	✔	(a)
Earthquake (greater than magnitude 6)	✔	n/a	(b)
Bushfire	✔	✔	✔
Damage to poles and lines	✔	✔	(a)
Key person	✔	✔	✔
General public liability	✔	✔	(a)
Key assets	n/a	✔	n/a
Guaranteed service level	n/a	✔	n/a
Non–terrorist impact of planes and helicopters	n/a	✔	n/a

Source: NSW DNSPs' regulatory proposals.

(a) SAHA suggested that the AER had not included Integral Energy's self insurance premium for bomb threat/hoax, terrorism[729], damage to poles and lines due to catastrophic storms[730] and general public liability[731] in its draft decision and requested that a premium be included. Based on the draft decision, the AER notes that Integral Energy did not include an estimate for self insurance for these events in its original regulatory proposal or the accompanying regulatory information notice. Further, Integral Energy's revised regulatory proposal does not include a request for inclusion of these costs.[732] As such, the AER has not included an allowance for these events in the final decision.

(b) Integral Energy did not included an allowance for earthquakes with a magnitude greater than 6 in the self insurance premium in its revised regulatory proposal.[733]

The revised self insurance allowances proposed by the NSW DNSPs are set out in table 8.20.

[729] SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 26.
[730] SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 46.
[731] SAHA, *Response to the AER's Draft Decision – Self Insurance*, confidential, p. 51.
[732] Integral Energy, *Revised regulatory proposal*, pp. 39–40.
[733] Integral Energy, *Revised regulatory proposal*, p. 40.

Table 8.20: NSW DNSPs' revised self insurance allowances for the next regulatory control period ($m, 2008–09)

	Country Energy		EnergyAustralia		Integral Energy	
	AER draft decision	**Revised regulatory proposal**	**AER draft decision**	**Revised regulatory proposal**	**AER draft decision**	**Revised regulatory proposal**
Total self insurance premium	15.0	19.5	20.4	29.5	9.6	16.1

Source: Country Energy, *Revised regulatory proposal*, p. 32; EnergyAustralia, *Email to the AER*, 12 February 2009 and Integral Energy, *Revised regulatory proposal*, p. 42.

Submissions

EnergyAustralia provided a submission in which it reiterated its objection to the AER's assessment of self insurance allowances.

AER considerations

Details of the AER's assessment of the NSW DNSPs' revised proposed self insurance allowances are provided at appendix M.

The AER considers that its approach to the assessment of the NSW DNSPs' self insurance claims and the proposed alternative self insurance amounts is consistent with the requirements of the transitional chapter 6 rules.

Based on its assessment of the relevant opex factors, the AER considers it necessary to rely on the information provided in the regulatory proposals (consistent with clause 6.5.6(e)(1) of the transitional chapter 6 rules) in determining whether the proposed self insurance allowances reasonably reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex criteria, including the opex objectives. Where the information concerning an individual self insurance claim was inadequate—that is, it did not appear to support the claim—the AER has not accepted the forecast (consistent with clause 6.5.6(d) of the chapter 6 transitional chapter 6 rules).

Similarly, in determining a substitute self insurance value, the AER relied on the information included in the regulatory proposals (as required by clauses 6.12.1(4)(iii) and 6.12.3(f) of the transitional chapter 6 rules). For a number of risks, based on the information provided to the AER in the regulatory proposals and revised regulatory proposals, the only value that the AER could estimate for an event for self insurance costs was zero—because there was no information provided to the AER in the regulatory proposals or revised regulatory proposals on which to base an alternative amount. Such a value is not meant to indicate that the self insurance event may or may not occur, rather, the AER has assigned a cost of zero due to the (lack of) information provided in the regulatory proposals.

The AER does not consider that the NSW DNSPs' proposed reinstatement of allowances for self insurance costs reasonably reflects the opex criteria, including the opex objectives. The AER is not satisfied that the NSW DNSPs, based on advice from SAHA, have always provided robust sufficient analysis which supports the probability of certain events occurring or that the costs of those events are reasonable. In these circumstances it has not accepted the calculation of the self insurance premiums for those events.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposals, the AER is satisfied that its amended estimates of the total self insurance allowances for the next regulatory control period the NSW DNSPs, set out in table 8.21, based on the accepted self insurance premiums and substitute values detailed in appendix M, reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

Table 8.21: AER conclusion on self insurance allowances costs for the NSW DNSPs ($2008–09)

	Country Energy		EnergyAustralia		Integral Energy	
	Revised regulatory proposal	AER final decision	Revised regulatory proposal	AER final decision	Revised regulatory proposal	AER final decision
Total self insurance	19.5	15.0	29.5	20.6	16.1	9.6

Note: EnergyAustralia's self insurance premiums in its regulatory proposal are in 2007–08 dollar terms. The AER converted these to 2008–09 dollar terms using EnergyAustralia's proposed 2.7 per cent escalation.

8.6 AER conclusion

8.6.1 Country Energy

The AER has considered Country Energy's forecast total opex of $2211 million ($2008–09) and for the reasons outlined in this chapter, the AER is not satisfied that this total opex forecast proposed by Country Energy reasonably reflects the opex criteria under clause 6.5.6(c) of the transitional chapter 6 rules, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

As the AER is not satisfied that Country Energy's total forecast opex reasonably reflects the opex criteria, under clause 6.5.6(d), the AER must not accept the forecast opex in Country Energy's revised regulatory proposal. Therefore, the AER is required under clause 6.12.1(4)(ii) of the transitional chapter 6 rules to provide an estimate of the total opex that Country Energy will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

After undertaking its own analysis of Country Energy's proposed total opex and based on the advice of Wilson Cook and EMS, the AER has applied a reduction of $159 million to Country Energy's proposed total opex. This represents a reduction of around 7.2 per cent of Country Energy's proposed opex of $2211 million and results in an amended forecast opex allowance of $2052 million.

This amended estimate represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of Country Energy would require to achieve the opex objectives, as required by clause 6.5.6(c)(2) of the transitional chapter 6 rules. The AER is satisfied that the amended total forecast opex of $2052 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. The amended opex allowance is set out by opex category in table 8.22.

Table 8.22: AER conclusion on Country Energy's total forecast opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy's revised controllable opex forecast	402.8	423.6	435.7	447.1	457.5	2166.7
Self insurance costs	3.9	3.9	3.9	3.9	3.9	19.5
Debt raising costs	4.0	4.5	5.0	5.5	6.1	25.0
Equity raising costs	–	–	–	–	–	–
Country Energy's total opex	410.7	432.0	444.6	456.5	467.4	2211.2
AER's adjusted controllable opex	389.9	397.8	405.3	411.8	416.2	2021.1
Self insurance costs	3.0	3.0	3.0	3.0	3.0	15.0
Debt raising costs	2.1	2.3	2.6	2.8	3.1	12.9
Equity raising costs[a]	–	–	–	–	–	–
Demand management innovation allowance[b]	0.6	0.6	0.6	0.6	0.6	3.0
AER's total opex	395.6	403.7	411.5	418.2	422.9	2052.0

Note: Totals may not add up due to rounding.
(a) The AER will allow Country Energy to amortise a total of $16.8 million ($2008–09) for benchmark equity raising costs associated with forecast capex for the next regulatory control period.
(b) Refer to chapter 14 for details on this allowance.

Table 8.23 sets out the AER's adjustments to Country Energy's forecast controllable opex allowance. These adjustments were derived by Country Energy from its opex model and reflect the AER's conclusion on an efficient controllable opex allowance.

In addition, the AER will allow Country Energy to amortise a total of $17 million ($2008–09) for benchmark equity raising costs for the next regulatory control period.

Table 8.23: AER conclusion on Country Energy's controllable opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER's controllable opex allowance (draft decision)	354.9	363.0	373.2	424.1	432.5	1947.7
Country Energy's revised controllable opex forecast	402.8	423.6	435.7	447.1	457.5	2166.7
Adjustment to project costs—Sheather decision	–	–10.1	–10.1	–10.1	–10.1	–40.2
Adjustment to vegetation management escalation	–1.6	–3.3	–5.1	–7.0	–8.8	–25.9
Adjustment to input cost escalators	–11.0	–11.9	–14.4	–17.1	–20.8	–75.2
Adjustment for revised capex forecast[a]	–0.3	–0.5	–0.8	–1.1	–1.6	–4.3
AER's adjusted controllable opex	389.9	397.8	405.3	411.8	416.2	2021.1

Note: Totals may not add up due to rounding.
(a) Updates arising from the AER amendments to the capex allowance set out in chapter 7.

8.6.2 EnergyAustralia

The AER has considered EnergyAustralia's forecast total opex of $2991 million ($2008–09) and for the reasons outlined in this chapter, the AER is not satisfied that this total opex forecast proposed by EnergyAustralia reasonably reflects the opex criteria under clause 6.5.6(c) of the transitional chapter 6 rules, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

As the AER is not satisfied that EnergyAustralia's total forecast opex reasonably reflects the opex criteria, under clause 6.5.6(d), the AER must not accept the forecast opex in EnergyAustralia's revised regulatory proposal. Therefore, the AER is required under clause 6.12.1(4)(ii) of the transitional chapter 6 rules to provide an estimate of the total opex that EnergyAustralia will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

After undertaking its own analysis of EnergyAustralia's proposed total opex and based on the advice of Wilson Cook, the AER has applied a reduction of $363 million to EnergyAustralia's proposed total opex. This represents a reduction of around 12 per cent of EnergyAustralia's proposed opex of $2991 million and results in an amended forecast opex allowance of $2628 million.

This amended estimate represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives, as required by clause 6.5.6(c)(2) of the transitional chapter 6 rules. The AER is satisfied that the amended total forecast opex of $2628 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. The amended opex allowance is set out by opex category in table 8.24.

Table 8.24: AER conclusion on EnergyAustralia's total forecast opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
EnergyAustralia's revised controllable opex forecast	548.8	566.9	582.8	601.6	610.8	2910.9
Self insurance costs	5.9	5.9	5.9	5.9	5.9	29.6
Debt raising costs	7.6	9.0	10.1	11.4	12.6	50.8
Equity raising costs	–	–	–	–	–	–
EnergyAustralia's total opex	562.4	581.8	598.9	618.9	629.3	2991.3
AER's adjusted controllable opex	497.4	507.4	517.8	526.9	527.7	2577.3
Self insurance costs	4.1	4.1	4.1	4.1	4.1	20.6
Debt raising costs	3.9	4.5	5.0	5.6	6.2	25.2
Equity raising costs[a]	–	–	–	–	–	–
Demand management innovation allowance[b]	1.0	1.0	1.0	1.0	1.0	5.0
AER's total opex	506.5	517.0	527.9	537.7	539.0	2628.1

Note: Totals may not add up due to rounding.
(a) The AER will allow EnergyAustralia to amortise a total of $38.0 million ($2008–09) for benchmark equity raising costs associated with forecast capex for the next regulatory control period.
(b) Refer to chapter 14 for details on this allowance.

Table 8.25 sets out the AER's adjustments to EnergyAustralia's forecast controllable opex allowance. These adjustments were derived by EnergyAustralia from its opex model and reflect the AER's conclusion on an efficient controllable opex allowance.

Table 8.25: AER conclusion on EnergyAustralia's controllable opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER's controllable opex allowance (draft decision)	490.2	502.8	518.5	535.1	545.3	2591.9
EnergyAustralia's revised controllable opex forecast	548.8	566.9	582.8	601.6	610.8	2910.9
Adjustment to network operating	–23.2	–27.9	–26.8	–28.0	–30.0	–135.9
Adjustment to network maintenance	–3.4	–4.3	–5.3	–6.8	–7.4	–27.2
Adjustment to other expenditure	–9.3	–9.8	–10.2	–9.9	–9.1	–48.3
Adjustment to labour escalators	–15.5	–17.6	–22.7	–29.9	–36.5	–122.2
AER's adjusted controllable opex	497.4	507.4	517.8	526.9	527.7	2577.3

Note: Totals may not add up due to rounding.

The AER's forecast total opex allowance for the distribution and transmission networks of EnergyAustralia is disaggregated as shown in table 8.26.

Table 8.26: AER conclusion on EnergyAustralia's total opex allowance—distribution and transmission ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Distribution network	471.4	482.2	493.3	502.9	505.0	2454.8
Transmission network	35.0	34.8	34.7	34.7	34.1	173.2
Total opex allowance	506.5	517.0	527.9	537.7	539.0	2628.1

Note: Totals may not add up due to rounding.

In addition, the AER will allow EnergyAustralia to amortise a total of $38 million ($2008–09) for benchmark equity raising costs for the next regulatory control period.

8.6.3 Integral Energy

The AER has considered Integral Energy's forecast total opex of $1521 million ($2008–09) and for the reasons outlined in this chapter, the AER is not satisfied that this total opex forecast proposed by Integral Energy reasonably reflects the opex criteria under clause 6.5.6(c) of the transitional chapter 6 rules, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

As the AER is not satisfied that Integral Energy's total forecast opex reasonably reflects the opex criteria, under clause 6.5.6(d), the AER must not accept the forecast opex in Integral Energy's revised regulatory proposal. Therefore, the AER is required under clause 6.12.1(4)(ii) of the transitional chapter 6 rules to provide an estimate of the total opex that Integral Energy will require over the next regulatory control period which the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

After undertaking its own analysis of Integral Energy's proposed total opex, the AER has applied a reduction of $4.3 million to Integral Energy's proposed total opex. This represents a reduction of around 0.3 per cent of Integral Energy's proposed opex of $1521 million and results in an amended forecast opex allowance of $1516 million.

This amended estimate represents the AER's estimate of the total opex costs that a prudent operator in the circumstances of Integral Energy would require to achieve the opex objectives, as required by clause 6.5.6(c)(2) of the transitional chapter 6 rules. The AER is satisfied that the amended total forecast opex of $1516 million over the next regulatory control period, reasonably reflects the opex criteria, taking into account the opex factors. The amended opex allowance is set out by opex category in table 8.27.

Table 8.27: AER conclusion on Integral Energy's total forecast opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Integral Energy's revised controllable opex forecast	289.6	291.0	296.5	302.7	303.8	1483.7
Self insurance costs	3.1	3.2	3.3	3.3	3.2	16.1
Debt raising costs	3.5	3.9	4.3	4.6	4.8	21.1
Equity raising costs	–	–	–	–	–	–
Integral Energy's total opex	296.3	298.1	304.0	310.5	311.9	1520.8
AER's adjusted controllable opex	293.2	295.4	299.7	303.3	301.9	1493.4
Self insurance costs	1.9	1.9	1.9	1.9	1.9	9.6
Debt raising costs	1.8	1.9	2.1	2.3	2.4	10.5
Equity raising costs[a]	–	–	–	–	–	–
Demand management innovation allowance[b]	0.6	0.6	0.6	0.6	0.6	3.0
AER's total opex	297.4	299.8	304.3	308.1	306.9	1516.5

Note: Totals may not add up due to rounding.
(a) The AER will allow Integral Energy to amortise a total of $9.4 million ($2008–09) for benchmark equity raising costs associated with forecast capex for the next regulatory control period.
(b) Refer to chapter 14 for details on this allowance.

Table 8.28 sets out the AER's adjustments to Integral Energy's forecast controllable opex allowance. These adjustments were derived by Integral Energy from its opex model and reflect the AER's conclusion on an efficient controllable opex allowance.

Table 8.28: AER conclusion on Integral Energy's controllable opex allowance ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
AER's controllable opex allowance (draft decision)	281.3	283.9	287.9	292.1	295.0	1440.1
Integral Energy's revised controllable opex forecast	289.6	291.0	296.5	302.7	303.8	1483.7
Adjustment to labour escalators	3.6	4.4	3.2	0.6	–1.9	9.8
AER's adjusted controllable opex	293.2	295.4	299.7	303.3	301.9	1493.4

Note: Totals may not add up due to rounding.

In addition, the AER will allow Integral Energy to amortise a total of $9 million ($2008–09) for benchmark equity raising costs for the next regulatory control period.

8.7 AER decision

In accordance with clause 6.12.1(4)(ii) of the transitional chapter 6 rules the AER does not accept Country Energy's proposed forecast opex for the next regulatory control period. The AER's reasons are set out in section 8.6 of the draft decision and section 8.5 of this final decision.

The AER's estimate of Country Energy's required opex for the next regulatory control period is set out in table 8.22 of this final decision.

In accordance with clause 6.12.1(4)(ii) of the transitional chapter 6 rules the AER does not accept EnergyAustralia's proposed forecast opex for the next regulatory control period. The AER's reasons are set out in section 8.6 of the draft decision and section 8.5 of this final decision.

The AER's estimate of EnergyAustralia's required opex for the next regulatory control period is set out in tables 8.24 and 8.26 of this final decision.

In accordance with clause 6.12.1(4)(ii) of the transitional chapter 6 rules the AER does not accept Integral Energy's proposed forecast opex for the next regulatory control period. The AER's reasons are set out in section 8.6 of the draft decision and section 8.5 of this final decision.

The AER's estimate of Integral Energy's required opex for the next regulatory control period is set out in table 8.27 of this final decision.

9 Estimated corporate income tax

9.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision and the AER's assessment of estimated corporate income tax liabilities for the NSW DNSPs during the next regulatory control period. No submissions were received on this issue.

9.2 AER draft decision

The AER assessed the inputs to the post–tax revenue model (PTRM) that were used to calculate the expected cost of corporate income tax in accordance with the transitional chapter 6 rules. The AER considered that each of the NSW DNSPs' proposed tax remaining and tax standard lives were appropriate. The AER also considered each of the NSW DNSPs' proposed opening tax asset bases to be appropriate and reasonable.[734] Using these inputs, the AER used the PTRM to calculate the allowance for corporate income tax as set out in table 9.1.

Table 9.1: AER draft decision on the NSW DNSPs' corporate income tax allowances ($m, nominal)

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

Source: AER, *Draft decision*, p. 210.

9.3 Revised regulatory proposals

The NSW DNSPs each submitted a revised allowance for corporate income tax in their revised regulatory proposals. For each of the NSW DNSPs, the method used to calculate the income tax allowance was consistent with the draft decision. However, the proposed tax asset bases were updated to include 2007–08 actuals for capex and tax depreciation rather than estimates. The updated tax asset bases as at 1 July 2009 are set out in table 9.2.

[734] AER, *Draft decision*, p. 210.

Table 9.2: NSW DNSPs' proposed tax asset bases ($m, 2008–09)

	Draft decision	Revised regulatory proposals	Difference	Reason for difference
Country Energy	2685.2	2699.3	14.1	Replaced 2007–08 estimates with actuals
EnergyAustralia	4961.5	4997.4	35.9	Replaced 2007–08 estimates with actuals
Integral Energy[a]	2459.0	2428.8	–30.2	Replaced 2007–08 estimates with actuals and updated CPI estimate[735] for the final year of the current regulatory control period.

Source: AER, *Draft decision*, pp. 205–206; Country Energy, *Revised regulatory proposal*, PTRM confidential; EnergyAustralia, *Revised regulatory proposal*, PTRM confidential; Integral Energy, *Revised regulatory proposal*, PTRM confidential and Integral Energy, email dated 19 February 2009.

(a) Integral Energy submitted further revisions by email on 19 February 2009. The further revised tax asset base included an additional $170 million to account for omitted assets. Integral Energy also provided corresponding tax remaining lives for the inclusion of these omitted assets for 1 July 2009.

The NSW DNSPs each proposed allowances for corporate income tax calculated by the PTRM as presented in table 9.3. These figures include the impact of the revised tax asset bases and other revised inputs to the PTRM such as the weighted average cost of capital, capex and opex.

Table 9.3: NSW DNSPs' proposed corporate income tax allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	45.3	51.9	45.6	53.6	59.2	255.7
EnergyAustralia	87.1	90.6	177.8	202.9	215.4	773.8
Integral Energy	41.5	42.9	45.0	42.7	46.6	218.7

Source: Country Energy, *Revised regulatory proposal*, PTRM confidential; EnergyAustralia, *Revised regulatory proposal*, PTRM confidential; and Integral Energy, *Revised regulatory proposal*, PTRM confidential.

9.4 Issues and AER considerations

9.4.1 Variations to opening tax asset base

As set out in table 9.2, each of the NSW DNSPs has proposed a different tax asset base to that accepted in the draft decision. In each case, the variance arises from updating 2007–08 data (which was estimated at the time the regulatory proposals were submitted) with actuals. Differences also arise from updated forecasts of capex in the final year of the current regulatory control period. The methodology used to derive the proposed tax asset bases have not been changed by any of the NSW DNSPs. Accordingly, the AER

[735] While tax is assessed in nominal terms, the CPI is relevant to capex forecasts for the final year of the current regulatory control period.

considers the tax asset bases set out in each of the NSW DNSPs' revised regulatory proposals are appropriate and reasonable.

Integral Energy omitted assets

On 19 February 2009, Integral Energy provided a revised estimate of its tax asset base which included $170 million for omitted assets.[736] This issue is discussed in chapter 5 of this final decision. Given the AER's conclusion with respect to Integral Energy's omitted assets, the AER considers the tax asset base in Integral Energy's revised regulatory proposal ($2435 million)[737] an appropriate input to the PTRM and rejects the further revisions proposed by Integral Energy on 19 February 2009.

9.4.2 Assessment of tax standard and tax remaining lives

Country Energy

Country Energy has applied tax standard and tax remaining lives that are consistent with those accepted in the draft decision.

EnergyAustralia

The AER accepted EnergyAustralia's tax standard lives in the draft decision.[738] As set out in the draft decision, EnergyAustralia directly input its tax depreciation amounts for its opening tax asset base into the PTRM and used the PTRM to calculate tax depreciation associated with forecast capex.[739] This methodology was accepted in the draft decision.[740] The AER identified that the tax standard life input for equity raising costs assumed in EnergyAustralia's revised regulatory proposal was in error. This was confirmed with EnergyAustralia and accordingly the AER has amended the input.[741] In all other respects, EnergyAustralia's proposed tax standard lives and tax depreciation methodology are consistent with those accepted in the draft decision.

Integral Energy

The AER observed minor amendments to the tax standard lives assumed for certain asset classes in Integral Energy's revised regulatory proposal. The AER confirmed with Integral Energy[742] that the revised tax standard lives come about because regulatory asset classes consist of a number of assets with different Australian Tax Office effective lives. Consequently, revisions to capex have resulted in a change to the weighted average values which are used to obtain the tax standard lives for asset classes.

Integral Energy also submitted further revisions to its tax remaining lives to account for both the reallocation of work in progress required by the draft decision[743] and the value of the regulatory asset base adjustment (for omitted assets which is discussed in chapter 5). The AER considers that the revised tax remaining lives provided on 19 February 2009 are appropriate and reasonable with the exception of the substations asset class which is affected by the inclusion of omitted assets. The AER considers that the tax remaining life

736 Integral Energy, email to AER, 19 February 2009.
737 Updated for work in progress.
738 AER, *Draft decision*, p. 210.
739 AER, *Draft decision*, p. 207.
740 AER, *Draft decision*, p. 207.
741 EnergyAustralia, email to AER, 16 February 2009.
742 Integral Energy, email to AER, 19 February 2009.
743 AER, *Draft decision*, p. 209.

for substations should be 30.4 years, not 31.5 years, consistent with its decision on Integral Energy's omitted assets.

9.5 AER conclusion

The AER has assessed each of the inputs to the PTRM that are used to calculate the expected cost of corporate income tax in accordance with clause 6.5.3 of the transitional chapter 6 rules. The AER considers the following tax asset bases proposed by the NSW DNSPs in their revised regulatory proposals[744] are appropriate and reasonable:

- Country Energy – $2699 million (nominal)
- EnergyAustralia – $4997 million (nominal)
- Integral Energy – $2435 million (nominal).

The AER rejects the further revision to the opening tax asset base proposed by Integral Energy for the inclusion of omitted assets.

The AER also considers that Country Energy's proposed tax remaining and tax standard lives are appropriate. The AER considers EnergyAustralia's proposed tax standard lives (as corrected) and tax depreciation methodology appropriate in the circumstances. The AER considers that Integral Energy's revised tax standard and tax remaining lives provided on 19 February 2009 are appropriate and reasonable once the remaining life for the substations asset class is adjusted to exclude omitted assets.

On the basis of these inputs, the PTRM has calculated the allowance for corporate income tax presented in table 9.4.

Table 9.4: AER conclusion on the NSW DNSPs' corporate income tax allowances ($m,nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	43.9	46.5	39.2	45.6	50.1	225.4
EnergyAustralia	34.0	64.6	73.7	84.0	88.0	344.4
Integral Energy	34.9	38.4	38.1	37.3	37.5	186.2

9.6 AER decision

In accordance with clause 6.12.1(7) of the transitional chapter 6 rules the estimated cost of corporate tax to Country Energy for each regulatory year of the next regulatory control period is specified in table 9.4 of this final decision.

744 Integral Energy's revised regulatory proposal amount of $2429 million was updated to $2435 million to account for work in progress.

In accordance with clause 6.12.1(7) of the transitional chapter 6 rules the estimated cost of corporate tax to EnergyAustralia for each regulatory year of the next regulatory control period is specified in table 9.4 of this final decision.

In accordance with clause 6.12.1(7) of the transitional chapter 6 rules the estimated cost of corporate tax to Integral Energy for each regulatory year of the next regulatory control period is specified in table 9.4 of this final decision.

10 Depreciation

10.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision regarding the annual allowances for regulatory depreciation—also referred to as the return of capital. Regulatory depreciation sums the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening regulatory asset base (RAB).

This chapter also sets out the AER's assessment of the NSW DNSPs' proposed asset lives used in the post–tax revenue model (PTRM) to calculate their depreciation schedules which are then used to determine the regulatory depreciation allowances for the next regulatory control period. There were no submissions received on this issue.

10.2 AER draft decision

The AER assessed each of the NSW DNSP's proposed asset class life inputs to the PTRM that are used to calculate depreciation schedules and the regulatory depreciation allowance. As a result of that assessment, the AER considered that the NSW DNSPs' proposed depreciation schedules did not comply with the transitional chapter 6 rules and therefore did not approve the schedules.[745]

On the basis of the approved asset lives, opening RABs and forecast capex allowances, the AER determined the NSW DNSPs' depreciation schedules and regulatory depreciation allowances. Table 10.1 sets out the AER's draft decision on the NSW DNSPs' regulatory depreciation allowances for the next regulatory control period.

Table 10.1: AER draft decision on the NSW DNSPs' regulatory depreciation allowances ($m, nominal)

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

Source: AER, *Draft decision*, p. 215.

10.3 Revised regulatory proposals

The NSW DNSPs' proposed revised regulatory depreciation schedules in response to the draft decision. The revised regulatory depreciation schedules resulted in the calculation of the revised regulatory depreciation allowances as set out in table 10.2.

[745] AER, *Draft decision*, p. 219

Table 10.2: NSW DNSPs' revised regulatory depreciation allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	152	175	140	162	183	812
EnergyAustralia	75	101	125	150	145	596
Integral Energy	164.7	129.4	130.3	114.6	118.1	657.1

Source: Country Energy, *Revised regulatory proposal*, p. 51; EnergyAustralia, *Revised regulatory proposal,* p. 14 and Integral Energy, *Revised regulatory proposal*, p. 55.

Country Energy

Country Energy accepted and implemented all aspects of the draft decision.[746] Country Energy re–allocated the value of the work in progress asset category across other asset classes to derive appropriate remaining asset lives for each asset class.[747]

EnergyAustralia

EnergyAustralia accepted the draft decision[748] and adjusted the standard asset life of the 'cable tunnel (dx)' asset class in its revised regulatory proposal PTRM to correct for an input error identified in the draft decision.[749]

Integral Energy

Integral Energy accepted the draft decision and re–allocated the value of the work in progress asset category across other asset classes. However, it did not update the estimated remaining life of each asset class to reflect this.[750]

Integral Energy also proposed a standard asset life of 38.5 years for the equity raising costs asset class, which it determined using a weighted average of the standard asset lives of both system and non–system assets.[751] This differs from the 43.2 year standard asset life determined by the AER in the draft decision using a weighted average of the standard asset lives of system assets alone.[752]

10.4 Issues and AER considerations

10.4.1 Equity raising costs standard asset life

AER draft decision

The AER determined that the standard asset life for the equity raising costs asset class was 43.2 years based on a weighted average of the standard asset lives of Integral Energy's system assets only.

[746] Country Energy, *Revised regulatory proposal*, p. 49.
[747] Country Energy, *Revised regulatory proposal*, p. 50.
[748] EnergyAustralia, *Revised regulatory proposal*, p. 12.
[749] EnergyAustralia, *Revised regulatory proposal*, p. 52.
[750] Integral Energy, *Revised regulatory proposal*, p. 53.
[751] Integral Energy, *Revised regulatory proposal*, p. 54.
[752] AER, *Draft decision*, PTRM.

Revised regulatory proposal

Integral Energy proposed to amend the standard asset life for the equity raising costs asset class using a weighted average of the approved standard asset lives of both system and non–system assets.[753]

AER considerations

The AER considers it reasonable that the standard asset life for the equity raising costs asset class be determined by reference to both system and non–system asset lives. The AER notes that the calculation of the allowance for equity raising costs is based on the total forecast capex, which encompasses both system and non–system assets. However, the standard asset life of 38.5 years proposed by Integral Energy for the equity raising costs asset class has been calculated using an opening RAB (for the weighting) that incorporates $170 million for omitted assets. As discussed in chapter 5 of this final decision, the AER has determined that the $170 million for omitted assets should be excluded from Integral Energy's opening RAB. In addition, adjustments to the formula to calculate a standard life for the equity raising costs asset class is also required. The AER has excluded this $170 million of assets and made adjustments to the formula to calculate a standard asset life for the equity raising costs asset class.

Given this consideration and despite Country Energy and EnergyAustralia accepting the standard asset life (based on weighted average of system assets) assigned for their equity raising costs asset class in the draft decision, the AER is of the view that, in this instance, it is appropriate to maintain a consistent approach to calculating the standard asset life for the equity raising costs asset class for this final decision. Accordingly, using the weighted average of the approved standard asset lives for both system and non–system assets, the AER has determined the standard asset life for the equity raising costs asset class for Country Energy and EnergyAustralia. The NSW DNSPs' standard asset life for the equity raising costs asset class is shown in table 10.3.

Table 10.3: AER conclusion on NSW DNSPs' standard asset life for equity raising costs asset class (year)

	Country Energy	Integral Energy	EnergyAustralia (distribution)	EnergyAustralia (transmission)
Standard asset life	44.7	41.0	47.4	45.7

10.4.2 Updating input data

The AER updated the input data used to determine regulatory depreciation allowances for each of the NSW DNSPs. The updated input data incorporates changes to the opening RAB for each business and changes to capex allowances as discussed in chapters 5 and 7 of this final decision.

Country Energy and EnergyAustralia updated their remaining asset lives for existing assets, which are used to calculate regulatory depreciation. The updated estimated remaining asset lives incorporate the actual capex for 2007–08, which differs from the forecast capex used in the draft decision. The AER has reviewed Country Energy and

753 Integral Energy, *Revised regulatory proposal*, p. 6

EnergyAustralia's updated remaining asset lives and considers that they have been calculated consistently with the method approved in the draft decision.

As noted above, Integral Energy did not update the estimated remaining life of each asset class to reflect the re–allocation of the work in progress asset category across other asset classes in its revised regulatory proposal. On 20 February 2009 Integral Energy provided updated remaining asset lives to incorporate this.[754] The updated remaining asset lives also incorporate the actual capex for 2007–08, which differs from the forecast capex used in the draft decision. The AER has reviewed Integral Energy's updated remaining asset lives and considers that they have been calculated appropriately, with the exception of the substations asset class which is affected by the inclusion of $170 million for omitted assets (as discussed in chapter 5 of this final decision). The AER considers that the remaining asset life for the substations asset class should be 20.2 years, not 21.7 years, consistent with its decision on Integral Energy's omitted assets.

10.5 AER conclusion

The AER has reviewed the inputs to the PTRM used by the NSW DNSPs to calculate depreciation schedules in accordance with clause 6.5.5 of the transitional chapter 6 rules. As a result of required adjustments to each NSW DNSP's opening RAB and capex allowance (as discussed in chapters 5 and 7 respectively), the AER has not approved the depreciation schedules proposed in the NSW DNSPs' revised regulatory proposals.

On the basis of the approved asset lives, opening RAB and forecast capex allowances, the AER has determined the NSW DNSPs' depreciation schedules. The depreciation schedules are used to calculate the regulatory depreciation allowances for the next regulatory control period in accordance with clause 6.5.5(a)(2)(ii) of the transitional chapter 6 rules, as set out in table 10.4.

Table 10.4: AER conclusion on the NSW DNSPs' regulatory depreciation allowances ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Country Energy	154.1	176.7	141.5	161.1	180.8	814.3
EnergyAustralia	80.0	106.9	131.0	156.6	151.8	626.2
Integral Energy	144.3	123.2	119.7	113.4	106.1	606.7

754 Integral Energy, Email – RE: Integral Energy – Variances to tax standard life assumptions and tax asset base, 20 February 2009.

10.6 AER decision

In accordance with clause 6.12.1(8) of the transitional chapter 6 rules, the AER has not approved the depreciation schedules submitted by Country Energy in its revised regulatory proposal. The AER has determined the depreciation schedule for Country Energy which results in the regulatory depreciation allowances set out in table 10.4 of this final decision.

In accordance with clause 6.12.1(8) of the transitional chapter 6 rules, the AER has not approved the depreciation schedules submitted by EnergyAustralia in its revised regulatory proposal. The AER has determined the depreciation schedule for EnergyAustralia which results in the regulatory depreciation allowances set out in table 10.4 of this final decision.

In accordance with clause 6.12.1(8) of the transitional chapter 6 rules, the AER has not approved the depreciation schedules submitted by Integral Energy in its revised regulatory proposal. The AER has determined the depreciation schedule for Integral Energy which results in the regulatory depreciation allowances set out in table 10.4 of this final decision.

11 Cost of capital

11.1 Introduction

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

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 set out in chapter 8 and the analysis of corporate tax is set out in chapter 9 of this decision.

11.2 AER draft decision

In the draft decision, the AER determined a nominal vanilla WACC of 9.72 per cent for each of the NSW DNSPs, based on the WACC parameter values as set out in table 11.1. 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 distribution determination.

Table 11.1: AER draft decision on WACC parameters

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

Source: AER, *Draft decision*, p. 229.

11.3 Revised regulatory proposals

The NSW DNSPs' revised regulatory proposals adopted a nominal vanilla WACC different to that determined in the draft decision. In estimating the WACC for their revised regulatory proposals, the NSW DNSPs adopted a different averaging period for the risk–free rate and debt risk premium. Country Energy and EnergyAustralia also rejected the use of only Bloomberg data to estimate the debt risk premium.

The NSW DNSPs implemented the AER's inflation forecast of 2.55 per cent in their revised regulatory proposals. However, they proposed that, if the AER did not accept the averaging period for the nominal risk–free rate proposed in their revised regulatory proposals, then the AER should reconsider its inflation estimate.

11.4 Submissions

The AER received submissions from EnergyAustralia and Integral Energy on the cost of capital. EnergyAustralia provided two submissions—a submission on the draft decision for EnergyAustralia and a submission on the AER's draft determinations for Country Energy and Integral Energy. Country Energy did not provide a submission on the cost of capital.

11.5 Issues and AER considerations

11.5.1 Risk–free rate

Averaging period

The NSW DNSPs initially proposed averaging periods for the nominal risk–free rate of 15 business days commencing close to the June 2008 submission of the regulatory proposals. The NSW DNSPs stated that the proposed periods provided the certainty they required to assess future capital expenditure programmes.

In July 2008, the AER determined that the proposed averaging periods were unreasonable and informed the NSW DNSPs of its decision to not accept the averaging periods in the regulatory proposals.[755]

The AER rejected the proposed averaging periods and noted that the start dates were 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.[756]

In July 2008, the AER advised the NSW DNSPs that the risk–free rate would be based on a 15 business day averaging period commencing on 2 March 2009 and ending on 20 March 2009. The AER invited the NSW DNSPs to nominate an averaging period

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755 AER, Letter to Country Energy rejection of risk–free rate, July 2008; AER, letter to EnergyAustralia rejection of risk–free rate, July 2008 and AER, Letter to Integral Energy rejection of risk–free rate, July 2008.

756 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; 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.

between 1 February 2009 and 20 March 2009 if they disagreed with the AER's nominated averaging period. In response, the NSW DNSPs nominated the periods shown in table 11.2, which were accepted by the AER (agreed averaging period).[757]

Table 11.2: The agreed risk–free rate averaging period

DNSP	Averaging period
Country Energy	15 business days, 2 February 2009 – 20 February 2009
EnergyAustralia	15 business days, 2 February 2009 – 20 February 2009
Integral Energy	15 business days, 2 March 2009 – 20 March 2009

Source: AER, Letter to Country Energy - Nominal risk–free rate averaging period for the 2009–14 regulatory control period, 18 August 2008; AER, Letter to EnergyAustralia - Nominal risk–free rate averaging period for the 2009–14 regulatory control period, 20 August 2008 and AER, Letter to Integral Energy - Integral Energy's proposed nominal risk–free rate averaging period for the 2009–14 regulatory control period, 11 August 2008.

AER draft decision

In the draft decision, the AER determined a nominal risk–free rate of 5.34 per cent based on a 15 day moving average of yields on Commonwealth Government Securities (CGS) with a 10–year maturity for the period ending 17 October 2008.[758] 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 were not disclosed in the draft decision due to requests by the NSW DNSPs for the periods to be kept confidential.

Revised regulatory proposals

The NSW DNSPs did not agree with the AER's July 2008 averaging period decision and 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 included as an attachment to each of the NSW DNSP's revised regulatory proposals.[759]

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.[760]

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

[757] Although the NSW DNSPs nominated averaging periods within the AER's specified range they expressed dissatisfaction with the decision.

[758] AER, *Draft decision*, p. 224.

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

[760] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 30–32.

- 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.[761]
- 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.[762]
- There has been a sudden fall in the 10–year break even (market inferred) inflation rate, which is either due to investors' increased demand for nominal CGS or alternatively lower inflation expectations.[763]

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:

> 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.[764]

CEG stated that an averaging period subject to market conditions post September 2008 would result in an estimate of the cost of equity that results in a rate of return inconsistent with clause 6.5.2(b) of the transitional chapter 6 rules.[765]

CEG stated that the reports by Lally and Davis, which the AER cited in its letters to the NSW DNSPs rejecting their proposed averaging periods, do not support the AER's averaging period decision. CEG noted that these reports state:[766]

- 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, which are aberrant and that the market risk premium is fixed based on historical data.[767]

CEG stated that previous regulatory decisions in Australia[768] as well as decisions in the UK and the US, have adjusted the averaging period for the risk–free rate to account for

[761] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 34–38.
[762] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 38–40.
[763] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 44–45.
[764] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 7.
[765] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 12.
[766] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 13.
[767] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 14.

specific events. CEG stated that these decisions support the use of an averaging period that excludes the impacts of the global financial crisis.[769]

CEG stated that there is no basis to presume that the yield on BBB+ debt prevailing at the beginning of the regulatory control period is a superior proxy for the businesses actual cost of debt than 12 months prior. CEG stated that this is particularly true because a regulated business is likely to re-finance or hedge its debt obligations over a longer period of time than one particular averaging period.[770] CEG stated that, given the increased discrepancies between the CBASpectrum and Bloomberg estimates of BBB rated corporate bond yields, an averaging period close to the final decision date could result in an inaccurate proxy for a regulated businesses actual cost of debt.[771]

Consistent with the NSW DNSPs regulatory proposals, CEG stated that 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.[772]

Country Energy's revised regulatory proposal

Country Energy proposed a nominal risk–free rate of 5.82 per cent, using an averaging period starting prior to 7 September 2008.[773]

EnergyAustralia's revised regulatory proposal

EnergyAustralia proposed a nominal risk–free rate of 5.82 per cent, using a 15 business day averaging period commencing 18 August 2008.[774]

Integral Energy's revised regulatory proposal

Integral Energy proposed a nominal risk–free rate of 5.82 per cent, using a 15 day averaging period ending on 5 September 2008. Integral Energy proposed that, if the averaging period for the risk–free rate was to include the effects of the global financial crisis, the AER should adopt a 12–month averaging period ending on the AER's nominated date of 20 March 2009. Integral Energy stated that this would ensure that a representative period was chosen for the calculation of the risk–free rate.[775]

Submissions

EnergyAustralia

EnergyAustralia's submission re–iterated its revised regulatory proposal, that the AER should use an averaging period for the risk–free rate that is unaffected by the global financial crisis. EnergyAustralia's submission referred to submissions made to the AER's

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768 ACCC, *Decision, Powerlink*; ESCV, *Final decision Electricity distribution price review 2006–10*, as amended by the appeal panel decision dated 17 February 2006, October 2006.

769 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 16.

770 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 19–25.

771 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 26.

772 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 26–28.

773 Country Energy, *Revised regulatory proposal*, pp. 57–58.

774 EnergyAustralia, *Revised regulatory proposal*, pp. 69, 72.

775 Integral Energy, *Revised regulatory proposal*, p. 60.

review of WACC parameters. It also referred to statements by the Institute of Actuaries Australia to support the revised averaging period for the risk–free rate.[776]

EnergyAustralia's submission included a peer review by Professor Robert Officer of the CEG report on the risk–free rate averaging period.[777] Professor Officer's peer review supported CEG's recommendation to use an averaging period prior to September 2008.

EnergyAustralia made a further submission on the AER's draft decision for other network service providers.[778] It supported the positions of other network service providers to adopt an averaging period prior to 5 September 2008 and requested that the AER consider the material presented as part of EnergyAustralia's revised regulatory proposal and submission when assessing the proposals of other network service providers.

On 25 March 2009 EnergyAustralia provided an additional submission reaffirming its revised regulatory proposal and attached a CEG memorandum.[779] It further stated that CEG's memorandum confirms that if the AER's averaging period is not changed, then that would result in the need for adjustments to take account of inconsistencies in inflation assumptions. It also submitted that, CEG's memorandum demonstrated that making the adjustments as suggested by EnergyAustralia's revised regulatory proposal to take account of inflation assumption inconsistencies does not result in a rate of return consistent with the NER.

Integral Energy

Integral Energy submitted that clause 6.5.2(c)(2)(i) of the transitional chapter 6 rules provides that the AER must not unreasonably withhold agreement to a DNSP's proposed averaging period for the nominal risk–free rate. Integral Energy submitted that the averaging period proposed in its revised regulatory proposal adequately responds to the AER's concerns in the draft decision. Integral Energy submitted that its revised averaging period is the closest period to the final decision date that takes into account the impact of the global financial crisis and therefore, the AER cannot reasonably withhold agreement to the revised averaging period.[780]

AER considerations

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

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776 EnergyAustralia, Further submission.

777 Officer R.R., *Expert report prepared in respect of certain matters arising from the AER's NSW draft distribution determination 2009-10 to 2013-14*, 16 February 2009.

778 EnergyAustralia, *Submission other network service providers*.

779 EnergyAustralia, Letter to the AER, 25 March 2009 and CEG, *Averaging period and impact on WACC, Memorandum*, 25 March 2009.

780 Integral Energy, *Submission to the AER*, pp. 14–15.

In summary, the AER considers that its decision to withhold agreement to the averaging periods in the NSW DNSPs' regulatory proposal was reasonable and that the agreed averaging periods are 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 regulatory proposals does not justify a conclusion that the AER's decision to withhold agreement to the proposed averaging periods and consequently the agreed averaging periods was inconsistent with regulatory practice.

The AER notes that the arguments put forward by the NSW DNSPs regarding an insufficient return on equity is based on the view that the market risk premium (MRP) of 6 per cent in the transitional chapter 6 rules (based on a historical average) is out of line with the current variations in the MRP. In essence, the NSW DNSPs are arguing for a variable MRP to be applied in the CAPM. However, given that the MRP is prescribed in the transitional chapter 6 rules, the NSW DNSPs appear 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) would circumvent WACC parameters prescribed and undermine the intended certainty under the regulatory regime which results from these values being prescribed.

The fact that CGS 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 the NSW DNSPs can lock in an averaging period that they consider achieves the most advantageous rate of return early in the regulatory process based on their view on future interest rate movements then it may create opportunities for 'gaming' the regulator if their view transpires to be disadvantageous. In June 2008 when the AER received NSW DNSPs' regulatory proposals 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 would be 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 the NSW DNSPs in support of their revised regulatory proposals does not reasonably justify that, an averaging period prior to 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 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 periods are not abnormal and setting the risk–free rate using this period is also consistent with the NEL objective of efficient investment.

The nominal risk–free rate averaging periods that the AER has adopted for the NSW DNSPs final decisions and the resulting proxy nominal risk–free rates (effective annual compounding rate) are shown in table 11.3. The AER is satisfied that these proxy nominal risk–free rates have been determined in accordance with clauses 6.5.2(c) and (d) of the transitional chapter 6 rules.

Table 11.3: AER conclusions on the nominal risk–free rate for the NSW DNSPs

NSW DNSP	Averaging Period	Nominal risk–free rate (effective annual compounding rate)
Country Energy	15 business days, 2 February 2009 – 20 February 2009	4.29%
EnergyAustralia	15 business days, 2 February 2009 – 20 February 2009	4.29%
Integral Energy	15 business days, 2 March 2009 – 20 March 2009	4.32%

11.5.2 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.[781] The debt risk premium was calculated using Bloomberg estimates of fair yields on long term corporate bonds, based on an averaging period of 15 business days ending 17 October 2008—consistent with the averaging period for the risk–free rate.[782]

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.[783] The review concluded that Bloomberg provided better estimates of 10–year BBB+ fair yields than CBASpectrum because they were more consistent with the observed yields of similarly rated actual 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.

NSW DNSPs revised regulatory proposals

The NSW DNSPs commissioned CEG to provide a report, which addressed the calculation of the debt risk premium.[784] Based on the CEG report, the NSW DNSPs proposed that the debt risk premium be calculated using an averaging period prior to 5 September 2008, consistent with the averaging period for the risk–free rate.

Country Energy did not address the methodology used to determine the debt risk premium. However, it appears that Country Energy has adopted an average of

781 AER, *Draft decision*, p. 226.
782 AER, *Draft decision*, p. 226.
783 AER, *Draft decision*, p. 225.
784 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009.

CBASpectrum and Bloomberg estimates for its revised regulatory proposal debt risk premium.

EnergyAustralia did not agree with the AER's methodology and cited CEG's analysis that the current lack of liquidity in the market for existing BBB+ corporate means that neither Bloomberg nor CBASpectrum data are likely to provide 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.

Integral Energy accepted the AER's methodology for calculating the debt risk premium.

Submissions

EnergyAustralia

EnergyAustralia's submission included a peer review by Professor Robert Officer of CEG's conclusions on the debt risk premium. Professor Officer's peer review did not agree with CEG's conclusion that there is no reason to presume that the yield on BBB+ rated corporate bonds at a date close to the final decision is a more accurate estimate than 12 months preceding the regulatory decision. Officer stated that, unless there is some other reason not to use the most up to date estimate, it will always be more accurate to use the current cost of debt.[785]

On 25 March 2009 EnergyAustralia provided a CEG memorandum to the AER in support of its revised regulatory proposal. The CEG memorandum recommended that the AER use CBASpectrum data alone to estimate the debt risk premium. EnergyAustralia stated that this advice demonstrated that its revised regulatory proposal approach to use an average of CBASpectrum and Bloomberg data to estimate the debt risk premium is reasonable.

Integral Energy

Integral Energy's submission stated that proposals from other network businesses, that the debt risk premium be calculated using an average of Bloomberg and CBASpectrum estimates of corporate bond fair yields, would provide a more reliable estimate of the debt risk premium. Integral Energy's submission stated that an average of the two services estimates should be applied consistently across all of the NSW DNSPs.[786]

EnergyAustralia's submission on other Network Service Providers

EnergyAustralia stated that CBASpectrum data may provide a more realistic reflection of market conditions. EnergyAustralia stated that, in any case, Bloomberg data by itself is not reflective of observed yields on 10–year corporate bonds. EnergyAustralia requested that the AER consider the material presented as part of EnergyAustralia's revised regulatory proposal and submission when assessing Country Energy and Integral Energy's proposals.

AER considerations

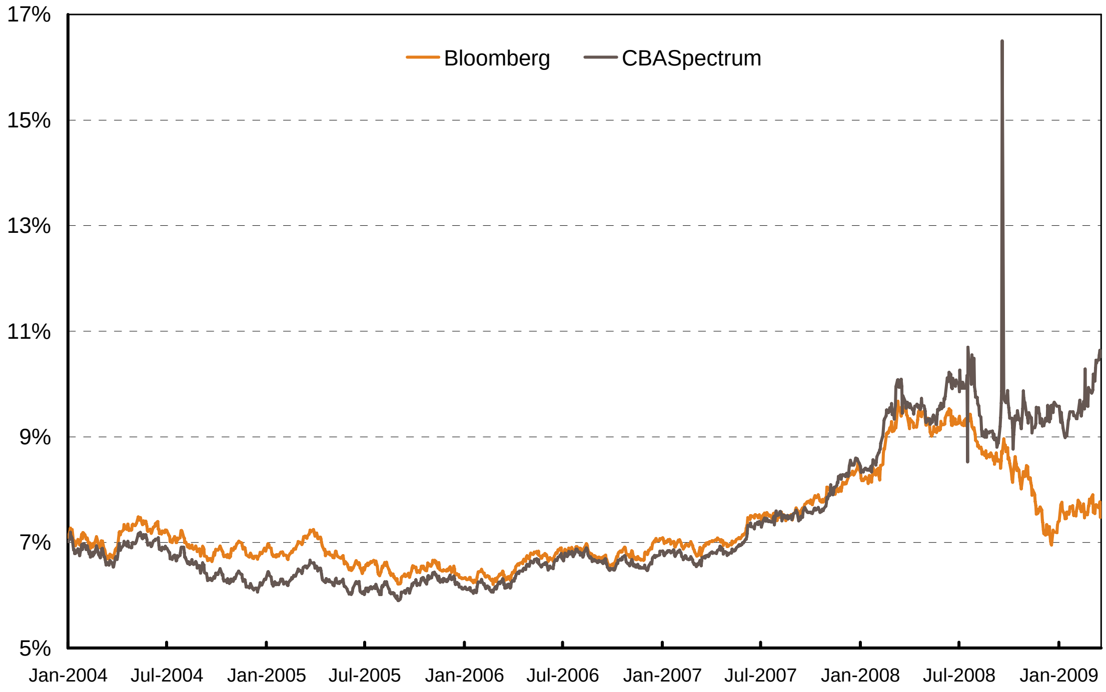
The AER notes that in their regulatory proposals the NSW DNSPs did not propose the use of CBASpectrum fair yield estimates in the calculation of the debt risk premium.

785 Officer R.R., pp. 16–17.
786 Integral Energy, *Submission to the AER*, p. 16.

EnergyAustralia and Integral Energy proposed that the AER adopt the same approach for calculating the debt risk premium as it employed in the final decision for SPAusNet, which relied on Bloomberg fair yield estimates.[787] Country Energy did not propose a method for calculating the debt risk premium in its regulatory proposal.

However, a significant divergence has developed over the past nine months between the corporate bond fair yields reported by Bloomberg[788] and CBASpectrum, as displayed in figure 11.1. 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 11.1: 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.[789] 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

787 EnergyAustralia, *Regulatory proposal*, p. 109.

788 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.

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

sources the AER agrees with EnergyAustralia[790] and Integral Energy[791] 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 11.4. The AER compared the observed yields of these bonds as quoted by both Bloomberg and CBASpectrum with the fair yields from the two sources.[792] The AER compared the actual observed bond yields with the fair yields from 2 February to 20 March, covering the averaging periods for the NSW DNSPs, ActewAGL, TransGrid and Transend. The average observed yields, and the average Bloomberg and CBASpectrum fair yields over the period analysed are outlined in table 11.4.

Table 11.4: 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:

- mean daily difference
- mean daily absolute difference

790 EnergyAustralia, *Revised regulatory proposal*, p. 72.
791 Integral Energy, *Submission to the AER*, p. 16.
792 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.

- mean daily squared difference.[793]

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 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 11.5.

Table 11.5: 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 11.5 the mean daily difference between the fair yield and the Bloomberg observed yield was much closer to zero for Bloomberg fair yields. Using Bloomberg fair yields also gave a significantly lower mean daily absolute difference and mean daily squared difference. For the CBASpectrum fair yields the mean daily difference equalled the mean daily absolute difference which indicates that for every day included in the analysis, the CBASpectrum fair yield was higher than the observed 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 11.6: 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

[793] The mean daily difference is the arithmetic mean of the difference between the observed 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 observed 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 observed yield of each bond and its corresponding estimated fair yield squared, calculated daily.

measures. Again, the results for CBASpectrum fair yields are the least favourable for all three measures. The results in table 11.6 also reflect the fact that the 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:

> …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.[794]

This was one of the conclusions of the Allen Consulting Group (ACG)[795] which undertook the analysis referred to by the ESCV. In its report, ACG stated that it considered that:

> … 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.[796]

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.[797]

However, ACG concluded that:

> 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.[798]

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.

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794 ESCV, *Gas access arrangement review 2008–2012: Final decision*, 7 March 2008, p. 487.
795 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.
796 ACG, *Memorandum*, p. 8.
797 ACG, *Memorandum*, p. 7.
798 ACG, *Memorandum*, p. 8.

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

In the 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.[799]

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.[800]

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.

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

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

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 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, the Babcock and Brown Infrastructure bond 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 bonds' 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 11.1). 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.

The AER notes that on 24 March 2009 Tabcorp announced a five year bond issue to be rated BBB+. The prospectus for the proposed Tabcorp bond issue outlines the interest payable will be a variable interest rate. The variable interest rate will be set for each interest period equal to the 3–month bank bill rate[801] plus a 'margin' of 4.25 per cent.[802] As at 23 March 2009, the initial interest rate would be 7.28 per cent.[803] 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 NSW DNSPs.[804]

Consistent with previous regulatory practice, the AER considers that the debt risk premium should be determined with reference to the same averaging period that was adopted for determining the risk–free rate. For this final decision, the 15 business day moving average benchmark debt risk premium, based on BBB+ rated corporate bonds with a maturity of 10 years, is as outlined in table 11.7. Adding this debt risk premium to the nominal risk–free rate provides a nominal return on debt, also in table 11.7. The AER is satisfied that the debt risk premium is consistent, under clause 6.5.2(e) of the transitional chapter 6 rules, 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.

Table 11.7: AER conclusion on the debt risk premiums for the NSW DNSPs

DNSP	Averaging period	Debt risk premium (per cent)	Risk–free rate (per cent)	Nominal return on debt (per cent)
Country Energy	2 February 2009 to 20 February 2009	3.48	4.29	7.78
EnergyAustralia	2 February 2009 to 20 February 2009	3.48	4.29	7.78
Integral Energy	2 March 2009 to 20 March 2009	3.52	4.32	7.84

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

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

803 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.

804 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.

11.5.3 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 the inflation forecasts proposed by the NSW DNSPs, which was based on advice commissioned from CEG. The inflation forecast recommended by CEG was calculated using a weighted average mean of professional economic forecasters' short and long–term inflation expectations, yielding an inflation rate of 2.54 per cent per annum.[805]

The AER determined that, consistent with its recent transmission determinations, an inflation forecasting methodology based on the RBA inflation forecasts and the mid–point of the RBA's target inflation band is objective and represents the best estimate of forecast inflation.[806] The AER noted that the inflation forecast would be updated using the latest forecasts at the time of the final decision.

NSW DNSPs revised regulatory proposals

The NSW DNSPs commissioned CEG to provide a report, which addressed the calculation of expected inflation.[807] 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 unreliablely 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.[808]

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

- retain the nominal CGS as the proxy for the nominal risk–free rate but use the break even inflation rate where it is less than the inflation forecast based on RBA projections
- 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.[809]

805 AER, *Draft decision*, 21 November, pp. 227–228.
806 AER, *Draft decision*, 21 November, p. 228.
807 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009.
808 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 64–65.

Country Energy suggested that the AER consider the approach set out in the CEG report for estimating expected inflation.[810]

EnergyAustralia and Integral EnergyAustralia stated that, if the AER used an averaging period for the risk–free rate at a date close to the final decision, to ensure that the inflation forecast and the nominal risk–free rate are applied consistently:

- the AER should use 10–year indexed CGS to estimate the real risk–free rate and add RBA inflation forecasts to determine the nominal risk–free rate, or
- the AER could adopt the break even inflation forecast implied by 10–year nominal and indexed CGS yields.[811]

Integral Energy stated that the AER should apply the option that results in the lower estimate of inflation.[812]

Submissions

On 25 March 2009 EnergyAustralia provided a CEG memorandum to the AER in support of its revised regulatory proposal.[813] The CEG memorandum agreed with EnergyAustralia's revised regulatory proposal position that if the averaging period for the risk–free rate is not changed, the AER should either use indexed CGS as a proxy for the real risk–free rate or adopt the break even inflation as the estimate for expected inflation.[814]

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, based on advice from CEG,[815] the NSW DNSPs initially proposed an inflation forecasting methodology broadly similar to that applied by the AER in the draft decision and previous determinations.[816] In April 2008, CEG agreed with the AER's methodology and did not propose the use of the break even inflation method to estimate the expected inflation rate due to concerns over the reliability of indexed CGS yields.

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

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809 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 65.

810 Country Energy, *Revised regulatory proposal*, pp. 58–59.

811 EnergyAustralia, *Revised regulatory proposal*, p. 70 and Integral Energy, *Revised regulatory proposal*, pp. 62–64.

812 Integral Energy, *Revised regulatory proposal*, pp. 62–64.

813 CEG, *Memorandum on averaging period and impact on WACC*, 25 March 2009.

814 CEG, *Memorandum on averaging period and impact on WACC*, 25 March 2009, p. 5.

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

816 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.

inflation remain valid. As outlined in the AER's 2007 SP AusNet draft decision,[817] 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.[818] The AER therefore considers that the lack of supply and liquidity in the market for indexed CGS appears not to have abated.

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 not more accurate.[819]

The AER notes that the real risk–free 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[820] does not accord with the requirement under clause 6.4.2 of the transitional chapter 6 rules to apply the methodology that will result in the best estimate of expected inflation. Further, the AER has determined that the 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

817 AER, *Draft decision, SP AusNet transmission determination 2008–09 to 2013–14*, 31 August 2007, pp. 114–124.
818 AOFM, *Annual Report 2007/08*, pp. 31, 116.
819 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 42.
820 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 46, 65.

determines is likely to result in the best estimate of expected inflation.[821] 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[822] 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 the mid–point of its target inflation band.

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[823] as shown in table 11.8. 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.[824] 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 this final decision.

The AER considers that, consistent with its draft decision methodology and based on a geometric average,[825]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 11.8: AER 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.

821 NER, transitional chapter 6 rules, clause 6.4.2(b)(1).

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

823 RBA, *Statement of Monetary Policy*, 6 February 2009, p. 65.

824 ActewAGL, *Revised regulatory proposal*, January 2009, p. 49.

825 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. Although the outcome is not significantly different, the AER agrees with ActewAGL that, for the purpose of averaging individual forecasts to derive the 1–year inflation forecast, a geometric average is more accurate. For consistency with the ACT distribution determination, the AER has applied a geometric average for the NSW DNSPs distribution determinations.

11.6 AER conclusion

The AER has determined a nominal vanilla WACC for each of the NSW DNSPs as set out in table 11.9. This WACC is based on the updated risk–free rate and debt risk premium, and other parameters prescribed in the transitional chapter 6 rules. The AER's WACC is lower than the WACC proposed by each of the NSW DNSPs in their revised regulatory proposals because of a lower nominal risk–free rate— commensurate with monetary policy and softening in economic growth—adopted for this final decision.

Table 11.9: AER conclusion on WACC parameters

Parameter	Country Energy	EnergyAustralia	Integral Energy
Risk–free rate (nominal)	4.29%	4.29%	4.32%
Risk–free rate (real)[a]	1.78%	1.78%	1.80%
Expected inflation rate	2.47%	2.47%	2.47%
Debt risk premium	3.48%	3.48%	3.52%
Market risk premium	6.00%	6.00%	6.00%
Gearing	60%	60%	60%
Equity beta	1.00	1.00	1.00
Nominal pre–tax return on debt	7.78%	7.78%	7.84%
Nominal post–tax return on equity	10.29%	10.29%	10.32%
Nominal vanilla WACC	8.78%	8.78%	8.83%

(a) The real risk–free rate was calculated using the Fisher equation.

The AER considers that its decision to withhold agreement to the averaging periods in the NSW DNSPs' regulatory proposals is reasonable and that the agreed averaging periods are consistent with finance theory, regulatory practice, the NER and NEL. The AER considers that the material provided by the NSW DNSPs in support of their revised regulatory proposals does not reasonably justify that an averaging period prior to 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.

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 post–tax revenue model for this final decision.

11.7 AER decision

In accordance with clause 6.12.1(5) of the transitional chapter 6 rules the rate of return to apply to Country Energy is 8.78 per cent.

In accordance with clause 6.12.1(5) of the transitional chapter 6 rules the rate of return to apply to EnergyAustralia is 8.78 per cent.

In accordance with clause 6.12.1(5) of the transitional chapter 6 rules the rate of return to apply to Integral Energy is 8.83 per cent.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the other appropriate amounts, values or inputs regarding WACC parameters to apply to Country Energy are as specified in table 11.9 of this final decision.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the other appropriate amounts, values or inputs regarding WACC parameters to apply to EnergyAustralia are as specified in table 11.9 of this final decision.

In accordance with clause 6.12.1(10) of the transitional chapter 6 rules the other appropriate amounts, values or inputs regarding WACC parameters to apply to Integral Energy are as specified in table 11.9 of this final decision.

12 Service target performance incentive arrangements

12.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision on service target performance incentive scheme (STPIS) arrangements for the NSW DNSPs.

12.2 AER draft decision

In accordance with the transitional chapter 6 rules, the AER decided it would collect and monitor the NSW DNSPs' service performance data during the next regulatory control period. It also decided that revenue would not be placed at risk under the data collection process during this period.[826]

In consultation with the NSW DNSPs, the AER developed service performance data reporting requirements for the next regulatory control period. As foreshadowed in the AER's decision on STPIS arrangements for the ACT and NSW determinations,[827] the data reporting requirements were aligned with the requirements of the national distribution STPIS.[828]

Whilst noting that full compliance with the reporting arrangements may not be realised before the commencement of the next regulatory control period the AER stated that it expected the NSW DNSPs to implement measures to achieve full compliance with the national distribution STPIS as soon as practical.[829]

12.3 NSW DNSP revised regulatory proposals

12.3.1 Country Energy

Country Energy agreed that the service performance reporting requirements require alignment to the national distribution STPIS. However, it was concerned about its ability to have systems implemented and tested by December 2009.[830]

Country Energy restated that it is unlikely to be able to provide full momentary average interruption frequency index (MAIFI) data for the next regulatory control period. It submitted that it is working towards collecting MAIFI data from parts of the network that have existing remote communications capability and circuit breakers and reclosers in zone substations with existing supervisory control and data acquisition connections.[831] It

[826] AER, *Draft decision*, p. 238.
[827] AER, *Final decision, STPIS arrangements for the ACT and NSW determinations*, February 2008, p. 15.
[828] AER, *Final decision, Electricity distribution service providers, STPIS*, June 2008.
[829] AER, *Draft decision*, p. 238.
[830] Country Energy, *Revised regulatory proposal*, p. 68.
[831] Country Energy, *Revised regulatory proposal*, p. 68.

submitted that equipping all other reclosers would be costly and can only occur over a longer period of time.[832]

Country Energy further submitted that the definition of the AER's frequency of interruption parameter requires further clarification, stating that the current definition is unworkable in Country Energy's distribution area.[833]

Country Energy also restated that the publication of two sets of data has the potential to confuse users.[834]

12.3.2 EnergyAustralia

EnergyAustralia restated its position that the STPIS reporting arrangements should use definitions, methods and exclusions consistent with those in the NSW distribution licence conditions.[835] It stated that, to do otherwise, would impose additional costs of reporting through maintaining two conflicting sets of data, without substantive benefit to EnergyAustralia's customers.[836]

EnergyAustralia did not provide an estimate of the additional costs associated with reporting against the AER's national distribution STPIS, however, it submitted that the following work would be required:[837]

- changes to the business reporting environment to accommodate two categories for each feeder, with ongoing maintenance and review of both feeder categories
- possible modifications to the outage management system and reporting environment, informed by an IT project
- additional calculations to determine major event day thresholds due to different data exclusions and additional steps in the calculation process of exclusions.

EnergyAustralia stated that, irrespective of the cost of additional reporting requirements, the AER has not provided sufficient evidence or analysis to demonstrate the benefits to customers from consistency in national standards.[838] It stated that the STPIS should be focussed on improving the performance of an individual DNSP relative to its service standard obligations.[839] It further noted that comparisons of DNSP service standard performance is complicated by factors such as type of network, topology and random seasonal and other impacts, potentially leading to the misinterpretation of the relative performance of the DNSPs.[840]

12.3.3 Integral Energy

Integral Energy submitted that it broadly supported the AER's proposed adoption of a 'paper–based STPIS trial' during the next regulatory control period, based on a generally

832 Country Energy, *Revised regulatory proposal*, p. 68.
833 Country Energy, *Revised regulatory proposal*, p. 69.
834 Country Energy, *Revised regulatory proposal*, p. 69.
835 EnergyAustralia, *Revised regulatory proposal*, p. 125.
836 EnergyAustralia, *Revised regulatory proposal*, p. 125.
837 EnergyAustralia, *Revised regulatory proposal*, p. 126.
838 EnergyAustralia, *Revised regulatory proposal*, p. 126.
839 EnergyAustralia, *Revised regulatory proposal*, p. 126.
840 EnergyAustralia, *Revised regulatory proposal*, p. 126.

applicable national scheme.[841] It restated that the reporting framework for the STPIS and the NSW licence conditions be aligned so that only one reporting regime is required, reducing the confusion for customers and other key stakeholders, and avoiding additional compliance costs.[842]

Integral submitted that it will actively participate in the STPIS data collection exercise to ensure that the scheme appropriately targets service incentives, while taking account of relevant regulatory obligations and other incentives in the framework, including the efficiency benefit sharing scheme (EBSS).[843]

12.4 Submissions

The Energy Users Association of Australia (EUAA) submitted that the AER should facilitate a working group of DNSPs and users to develop and implement a STPIS regime within 12 months of the start of the next regulatory control period.[844] It submitted that the regime should include both service reliability and service quality aspects.[845] It also sought clarification on the AER's reasons for not applying a STPIS during the next regulatory control period.[846]

The Energy Market Reform Forum (EMRF) restated that the AER should apply a STPIS during the next regulatory control period. It submitted that allowing the proposed amounts of capex and opex, much of which is to improve service performance, without imposing some incentive on performance appears to be contradictory.[847]

EnergyAustralia noted that the AER had proposed amendments to the national distribution STPIS. It stated that it intended to provide a separate submission to the AER on these proposed amendments.[848]

12.5 Issues and AER considerations

12.5.1 Application of a STPIS

The AER notes the EUAA's and EMRF's submissions that the AER should apply a STPIS during the next regulatory control period.

The AER consulted with interested parties in late 2007 on the ACT and NSW STPIS arrangements for the next regulatory control period. The AER's decision, reasoning and responses to submissions received during that consultation process are detailed in its final decision, published on 29 February 2008.[849] The AER notes that it is now precluded from applying a STPIS to the NSW distribution determinations under clause 6.6.2(g) of the transitional chapter 6 rules, which states:

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841 Integral Energy, *Revised regulatory proposal*, p. 66.
842 Integral Energy, *Revised regulatory proposal*, p. 67.
843 Integral Energy, *Revised regulatory proposal*, p. 67.
844 EUAA, p. 19.
845 EUAA, pp. 6–7 and 27.
846 EUAA, p. 19.
847 EMRF, pp. 44–45.
848 EnergyAustralia, *Further submission*, pp. 13–14.
849 AER, *Final decision, Service target performance incentive arrangements for the ACT and NSW 2009 distribution determinations*, 29 February 2008.

> If a service target performance incentive scheme applicable to a NSW or ACT Distribution Network Service Provider is not published before 1 March 2008 or the date that is one month after the commencement date [1 January 2008] (whichever is the later), no service target performance incentive scheme may be applied to the Distribution Network Service Provider in its distribution determination for the regulatory control period 2009-2014.

The AER will collect and monitor service performance data from the NSW DNSPs and expects to begin applying financial rewards and penalties from the beginning of the 2014–19 regulatory control period, as required under clause 6.6.2(h) of the transitional chapter 6 rules. In addition, the NSW DNSPs will continue to have an obligation to publish their performance data and report to the Minister (NSW Department of Water and Energy), in accordance with their distribution licences. The AER considers that these two measures will continue to support the transparent reporting of reliability outcomes for NSW distribution customers during the next regulatory control period.

The NSW DNSPs have an ongoing obligation to improve network reliability and security to ensure compliance with their mandated licence condition targets. Significant proportions of the forecast capex and opex allowances approved by the AER specifically target these reliability improvements during the next regulatory control period. The AER considers that if the planned projects and programs targeted at reliability improvement are implemented as proposed, network reliability performance in NSW is likely to improve rather than diminish during the next regulatory control period, thereby meeting the objectives of user groups.

12.5.2 Rationale for a national distribution STPIS framework

The AER notes EnergyAustralia's submission questioning the benefits of national consistency in service standards.[850] The AER considers a nationally consistent service incentive regime is desirable, and necessary. In reaching this conclusion the AER has considered the following factors:

- As the national regulator, the AER is tasked with developing and applying a national service standards regime for DNSPs in the NEM. The STPIS is part of the suite of regulatory requirements designed to streamline and improve the quality of economic regulation of energy networks, reduce regulatory costs and enhance regulatory certainty, consistent with the Council of Australian Government's objectives.[851]
- The value in applying a nationally consistent framework, including parameter definitions is in the ability to make relative comparisons of DNSPs performance, over time. This will allow the identification of trends in network reliability and service quality. This is important for ensuring transparency of performance outcomes. Specifically, it will provide a key indication of the effectiveness of the DNSPs' capex and opex programs for reliability improvement over time.
- Implementing a nationally consistent framework and definitions will minimise administration and compliance costs as the AER assumes regulatory responsibilities for a large number of DNSPs in the coming years.

850 EnergyAustralia, *Revised regulatory proposal*, p. 126.

851 AER, *Explanatory statement, proposed amendment, Service performance incentive scheme, electricity distribution network service providers*, February 2009, p. 3.

- The AER considers that following the passage of the proposed amendment to the national STPIS (discussed below), the AER's scheme will represent best regulatory practice in the area of service incentive schemes in Australia.
- The AER does not consider the potential for confusing customers and stakeholders is a compelling reason for not moving to a nationally consistent service standards reporting regime. The AER expects that the two sets of data can be clearly distinguished when reported by the DNSPs, minimising confusion and misinterpretation.

12.5.3 Proposed amendments to the national distribution STPIS

The AER notes the submissions of EnergyAustralia and Integral Energy requesting the alignment of the AER's data collection requirements to the existing NSW licence conditions.

In February 2009 the AER published a draft proposed national distribution STPIS incorporating some amendments and clarifications to the operation of the STPIS.[852] The amendments aim to remove potentially unintended consequences and to improve transparency in the operation of the scheme.[853] In summary, the proposed amendments:

- increase the cap on revenue at risk
- delete step 2 from the major event day calculation process set out at appendix D of the STPIS
- provide for the annual updating of the major event day threshold, consistent with the Institute of Electrical and Electronic Engineers (IEEE) standard 1366–2003[854]
- clarify the application of the IEEE standard 1366–2003 exclusion methodology for major event days.

The AER considers that these amendments, if made, will closer align the AER's national distribution STPIS with the IEEE standards, including mirroring aspects which are currently featured in the NSW licence conditions. The AER notes that the proposed amendments to the national distribution STPIS will reduce the resulting costs incurred in complying with the STPIS data reporting arrangements.

The AER acknowledges that there may still be a need to maintain two sets of data to reflect different feeder categorisation definitions, as the NSW licence conditions impose a CBD feeder definition which is inconsistent with the more commonly applied definitions recommended by the Steering Committee on National Regulatory Reporting Requirements.[855]

The proposed amendments to the national distribution STPIS are subject to a separate consultation process. As such, these are not matters for consideration within this

[852] AER, *Proposed electricity distribution network service providers service target performance incentive scheme*, February 2009.

[853] AER, *Explanatory statement, proposed amendment, Service performance incentive scheme, electricity distribution network service providers*, February 2009, p. 1.

[854] IEEE, Power Engineering Society, *IEEE guide for electric power distribution reliability indices*, New York, 2004.

[855] Utility Regulators Forum, *National regulatory reporting for electricity distribution and retailing businesses*, March 2002.

distribution determination. Submissions on the AER's draft decision relating to proposed amendments to the national distribution STPIS, including matters raised by Country Energy regarding parameter definitions, will be considered under that separate process.

As stated in its draft decision, should the national distribution STPIS be amended following the establishment of data reporting requirements set out in this final decision, the AER will advise the NSW DNSPs of any resulting changes to reporting requirements for the purposes of the data collection process under clause 6.6.2(h) of the transitional chapter 6 rules.

12.6 AER conclusion

The AER notes that under clause 6.6.2(h) of the transitional chapter 6 rules it must monitor and collect information from any or all of the NSW DNSPs and ActewAGL on matters relevant to be included in the STPIS for the purpose of developing, amending or applying a STPIS for the regulatory control period commencing on 1 July 2014.

The AER maintains its draft decision to collect and monitor service performance data during the next regulatory control period in accordance with clause 6.6.2(h) of the transitional chapter 6 rules. Revenue will not be placed at risk under the data collection process during this period.

The AER acknowledges that the NSW DNSPs may not achieve full compliance with the data reporting requirements before December 2009. However, the AER expects the NSW DNSPs to implement measures to achieve full compliance with the national distribution STPIS as soon as practical.

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

The AER will not apply a STPIS to the NSW DNSPs for the next regulatory control period. Clause 6.12.1(9) of the transitional chapter 6 rules requires the AER to make a decision on how any applicable STPIS will apply to the NSW DNSPs. As a STPIS will not apply to the NSW DNSPs, the AER is not required to make a decision with respect to a STPIS under clause 6.12.1(9) of the transitional chapter 6 rules for the NSW DNSPs.

Further, as the AER has not applied a STPIS to the NSW DNSPs for the next regulatory control period, it has not specified how a STPIS will apply to the NSW DNSPs as set out in clause 6.3.2(a)(3) of the transitional chapter 6 rules.

13 Efficiency benefit sharing scheme

13.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision and how the AER intends to apply its efficiency benefit sharing scheme (EBSS) to the NSW DNSPs.

An EBSS shares between a DNSP and its customers the efficiency gains or losses derived from the difference between a DNSP's actual opex and the forecast opex allowance for a regulatory control period. The AER published an EBSS, under clause 6.5.8(a) of the transitional chapter 6 rules, which established the scheme that will apply to the NSW DNSPs from 1 July 2009.[856] The scheme will not have a direct financial impact on the NSW DNSPs until the 2014–19 regulatory control period, when the DNSPs will receive carryover benefits/penalties for efficiency gains/losses made during the next regulatory control period.

13.2 AER draft decision

The AER stated it would apply the EBSS released in February 2008 to the NSW DNSPs for the next regulatory control period. The AER decided the following opex cost categories would be excluded from the operation of the EBSS for the next regulatory control period:[857]

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

These cost categories were in addition to the costs associated with pass through events that would be directly excluded by the EBSS.

13.3 Revised regulatory proposals

Country Energy stated that it was not seeking to add further exclusions to the scheme and that it looked forward to working with the AER on establishing the framework for the timing, content and verification of EBSS claims.[858]

EnergyAustralia did not comment on the draft decision regarding the application of the EBSS.[859]

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856 AER, *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, February 2008.
857 AER, *Draft decision*, pp. 246–247.
858 Country Energy, *Revised regulatory proposal*, pp. 67–68.
859 EnergyAustralia, *Revised regulatory proposal*, p. 125.

Integral Energy proposed that the EBSS be adjusted where there is a movement of costs between capital and operating expenditure during the regulatory control period. Integral Energy also proposed that symmetrical uncontrollable costs, and specifically costs relating to defined benefits superannuation liabilities, should be included in the operation of the EBSS.[860]

13.4 Submissions

Country Energy stated that the adjustment for changes in capitalisation policies should be extended to cover events where the legal form of a transaction results in costs moving between opex and capex during the next regulatory control period.[861]

13.5 Issues and AER considerations

13.5.1 Extension of exclusions for changes in capitalisation polices

The EBSS to apply to the NSW DNSPs in the next regulatory control period only applies to opex. This can influence the incentive for a DNSP to achieve an outcome through capex rather than opex, and vice versa.

AER draft decision

In the draft decision, the AER considered that it was appropriate to apply the EBSS released in February 2008, which applies only to opex.[862] The EBSS requires that where capitalisation policies change during the regulatory control period the forecast opex amounts used to calculate the EBSS carryover amounts must be adjusted to ensure they are consistent with the changed capitalisation policy.

Revised regulatory proposals

Integral Energy proposed that the EBSS be adjusted where the legal form of an expense, and therefore the accounting classification of the service received by Integral Energy, results in a movement of costs between capex and opex during the regulatory control period.[863]

Integral Energy cited the example of choosing between purchasing or leasing assets. The service secured would be the same, for example, the use of a motor vehicle. The only difference would be the manner in which the services would be secured and how the transaction would be reported financially.[864]

Submissions

Country Energy stated that the adjustment for changes in capitalisation policies should be extended to cover events where the legal form of a transaction results in costs moving between opex and capex during the next regulatory control period.[865] Country Energy noted that it owns all its assets. If it were to lease these assets the costs would move from

860 Integral Energy, *Revised regulatory proposal*, pp. 69–70.
861 Country Energy, *Draft NSW distribution determination*, p. 3.
862 AER, *Draft decision*, p. 246.
863 Integral Energy, *Revised regulatory proposal*, p. 69.
864 Integral Energy, *Revised regulatory proposal*, p. 69.
865 Country Energy, *Draft NSW distribution determination*, p. 3.

capex to opex. Country Energy considered that the EBSS should be adjusted if such an event occurred in the next regulatory control period.[866]

AER considerations

The AER has analysed the impact that the EBSS has on the interaction between capex and opex in its development of the EBSS to apply to ACT and NSW DNSPs as well as the national EBSS.[867]

The AER notes that the EBSS to apply to the NSW DNSPs in the next regulatory control period states:

> In calculating the benefits or losses to be carried over, the measurement of actual expenditure over the regulatory control period must be done using the same cost categories and methodology used to calculate the forecast expenditure for that period. Adjustments will be made where necessary to correct for variances in cost categories and methodologies, and errors.[868]

That is, the EBSS requires that the actual opex amounts used to calculate carryover amounts should represent the same costs included in the forecast amounts. Consequently, where a DNSP decides to lease equipment that it previously purchased, and those lease costs are not included in the forecast opex amounts, then those lease costs should be excluded from the actual opex amounts used in the calculation of EBSS carryover amounts. This ensures that the EBSS does not provide an inappropriate incentive to continue purchasing equipment when it is more efficient to lease that equipment.

The AER considers that this adjustment mechanism existing in the EBSS addresses the concerns raised by Integral Energy and Country Energy.

13.5.2 Symmetric uncontrollable costs

AER draft decision

In the draft decision, the AER concluded that the following cost categories should be excluded from the operation of the EBSS:[869]

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

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866 Country Energy, *Draft NSW distribution determination*, p. 3.

867 AER, *Final decision: Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, February 2008; AER, *Explanatory statement: Proposed electricity distribution network service providers efficiency benefit sharing scheme*, April 2008; and AER, *Final decision: Electricity distribution network service providers: Efficiency benefit sharing scheme*, June 2008.

868 AER, *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, February 2008, p. 5.

869 AER, *Draft decision*, pp. 246–247.

The primary considerations for excluding these cost categories were whether the cost category was controllable and how actual expenditure for that cost category would be used in setting opex forecasts for the following regulatory control period.[870]

Revised regulatory proposals

Integral Energy proposed that symmetrical uncontrollable costs be included in the operation of the EBSS. Integral Energy considered this would be appropriate, despite the costs being uncontrollable, because the EBSS would smooth the impacts of any windfall gains and losses over time and provide more equitable sharing of the risks and benefits of uncontrollable costs. On this basis, Integral Energy proposed that costs relating to defined benefits superannuation liabilities should be included in the operation of the EBSS.[871]

AER considerations

The AER notes that in the draft decision superannuation costs relating to defined benefit schemes were to be excluded from the operation of the EBSS on the basis that those cost would be uncontrollable.[872] Where a cost category is excluded from the EBSS, the impact of any changes in that cost from the forecast amount will depend on:

- whether the change is ongoing or transitory
- the year in the regulatory control period in which the change occurs.

The AER considers if the EBSS was applied to a cost category that is uncontrollable, the impact of any variance from the forecast expenditure would be the same regardless of whether the change is ongoing or transitory, or when the change occurs. However, this outcome of the EBSS is based on the assumption that actual expenditure during the regulatory control period is used as a basis for setting future expenditure allowances.

However, actual superannuation costs are not the basis for forecast costs. For example, Integral Energy stated that the costs of contributing to defined benefits superannuation schemes have increased due to significant reductions in the value of superannuation portfolios.[873]

Consequently, the AER considers that superannuation costs relating to defined benefit schemes should be excluded from the EBSS because these costs are not forecast on the basis of actual costs.

13.6 AER conclusion

The AER will apply the EBSS released in February 2008 to the NSW DNSPs for the next regulatory control period. In accordance with the draft decision the AER will not adjust the EBSS for the consequences of changes in demand growth for the next regulatory control period.

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

870 AER, *Draft decision*, p. 244.
871 Integral Energy, *Revised regulatory proposal*, pp. 69–70.
872 AER, *Draft decision*, p. 245.
873 Integral Energy, *Revised regulatory proposal*, pp. 38–39.

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

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

The forecast controllable opex for each of the NSW DNSPs is outlined in tables 13.1 to 13.3 and will be used to calculate efficiency gains and losses for the next regulatory control period, subject to adjustments required by the EBSS.

Table 13.1: Country Energy's forecast controllable opex for EBSS purposes ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total forecast opex	395.6	403.7	411.5	418.2	422.9	2052.0
Adjustment for debt raising costs	2.1	2.3	2.6	2.8	3.1	12.9
Adjustment for self insurance	3.0	3.0	3.0	3.0	3.0	15.0
Adjustment for insurance	5.6	5.7	5.8	6.0	6.2	29.3
Adjustment for superannuation	20.9	21.0	21.7	22.7	23.7	110.0
Adjustment for non–network alternatives	0.6	0.6	0.6	0.6	0.6	3.0
Forecast opex for EBSS purposes	363.4	371.1	377.8	383.2	386.4	1881.8

Note: Totals may not add up due to rounding.

Table 13.2: EnergyAustralia's forecast controllable opex for EBSS purposes ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total forecast opex	506.5	517.0	527.9	537.7	539.0	2628.1
Adjustment for debt raising costs	3.9	4.5	5.0	5.6	6.2	25.2
Adjustment for self insurance	4.1	4.1	4.1	4.1	4.1	20.6
Adjustment for insurance	6.1	6.1	6.1	6.1	6.1	30.4
Adjustment for superannuation	–	–	–	–	–	–
Adjustment for non–network alternatives	4.9	4.9	5.0	5.0	5.0	24.8
Forecast opex for EBSS purposes	487.5	497.4	507.8	516.9	517.6	2527.1

Note: Totals may not add up due to rounding.

Table 13.3: Integral Energy's forecast controllable opex for EBSS purposes ($m, 2008–09)

	2009–10	2010–11	2011–12	2012–13	2013–14	Total
Total forecast opex	297.4	299.8	304.3	308.1	306.9	1516.5
Adjustment for debt raising costs	1.8	1.9	2.1	2.3	2.4	10.5
Adjustment for self insurance	1.9	1.9	1.9	1.9	1.9	9.6
Adjustment for insurance	6.2	6.2	6.2	6.2	6.2	31.0
Adjustment for superannuation	–	–	–	–	–	–
Adjustment for non–network alternatives	2.1	2.2	2.2	2.2	2.2	10.9
Forecast opex for EBSS purposes	285.5	287.6	291.9	295.5	294.1	1454.6

Note: Totals may not add up due to rounding.

In accordance with clause 6.3.2(a)(3) of the transitional chapter 6 rules the EBSS to apply to the NSW DNSPs is as specified in this section 13.6.

13.7 AER decision

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the EBSS to apply to Country Energy is as defined in the AER's *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, published in February 2008. The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

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

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

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the EBSS to apply to EnergyAustralia is as defined in the AER's *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, published in February 2008. The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

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

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

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the EBSS to apply to Integral Energy is as defined in the AER's *Efficiency benefit sharing scheme for the ACT and NSW 2009 distribution determinations*, published in February 2008. The following opex cost categories will be excluded from the operation of the EBSS for the next regulatory control period:

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

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

14 Demand management incentives

14.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision. It also sets out the AER's demand management incentive scheme (DMIS) to apply to the NSW DNSPs for the next regulatory control period. The DMIS which will apply to the NSW DNSPs has two components: a demand management innovation allowance (DMIA) scheme; and the existing D–factor scheme developed and applied by IPART in its 2004 determination.

In February 2008 the AER released a DMIA scheme to apply to the NSW DNSPs in the next regulatory control period.[874] Between February 2008 and the release of the draft decision, the AER carried out further investigation on the optimum design of the DMIA, and developed a replacement DMIA. The replacement DMIA aims to provide incentives for the NSW DNSPs to pursue innovative broad based non–network solutions to growing demand and constraints on their networks.

This chapter sets out the AER's considerations and conclusions on how the DMIA and D–factor scheme should apply to the NSW DNSPs over the next regulatory control period.

14.2 AER draft decision

The AER decided to apply the D–factor scheme to the NSW DNSPs over the next regulatory control period, in the form applied by IPART over the current regulatory control period.[875]

The draft decision, subject to the agreement of the NSW DNSPs (as the affected DNSPs), amended the DMIA published on 29 February 2008, by replacing it with the DMIA specified in *Demand management incentive scheme for the ACT and NSW distribution determinations* (the replacement DMIA).[876] The replacement DMIA was published concurrently with the draft decision.

14.3 Revised regulatory proposals

14.3.1 Country Energy

Country Energy stated that the replacement DMIA is an improvement on the original DMIA,[877] however it did not expressly state its agreement to amend the original scheme by applying the replacement DMIA over the next regulatory control period. Country Energy submitted that the DMIA needs to be increased to promote meaningful demand management, and suggested that an amount of between 1 and 5 per cent of annual revenue requirements would be fair and reasonable.[878]

[874] AER, *Final Decision: DMIS*.
[875] AER, *Draft decision*, p. 268.
[876] AER, *Draft decision*, p. 268.
[877] Country Energy, *Revised regulatory proposal*, p. 67.
[878] Country Energy, *Revised regulatory proposal*, p. 67.

14.3.2 EnergyAustralia

14.3.2.1 D–factor

EnergyAustralia noted the AER's position that demand and energy forecasts for the next regulatory control period will incorporate reduced demand resulting from the implementation of demand management projects in the current regulatory control period.[879] However, it stated that this is only the case if the changes in demand are evident at the time of preparing the demand and energy forecasts. EnergyAustralia indicated that demand management projects carried out in the final two years of the current regulatory control period may not be evident in the demand forecasts for the next regulatory control period, and as such should be recovered under the D–factor during the next regulatory control period.[880]

14.3.2.2 DMIA

EnergyAustralia stated that it considers the replacement DMIA is a reasonable approach to the issues raised in its regulatory proposal.[881] However, it did not provide express agreement with the application of the replacement DMIA over the next regulatory control period.

EnergyAustralia noted that while the replacement DMIA incorporates a number of suggestions made by it regarding the operation of the scheme, the replacement DMIA does not incorporate its following recommendations:[882]

- that any unspent DMIA be rolled forward into the following regulatory control period, and that the administration of the DMIA be allowed to continue into the following regulatory control period until all funds are exhausted
- that the DMIA include recognition for the time value of money invested in innovation projects consistent with the timing of investments in the post–tax revenue model (PTRM).

14.3.3 Integral Energy

Integral Energy stated that it generally supports the AER's approach to the DMIA. However, its agreement to the application of the replacement DMIA for the next regulatory control period is dependent upon the AER increasing its allowance under the scheme to be in line with EnergyAustralia's allowance of $1 million per annum.[883] Integral Energy submitted that this proposed increase reflects its view that the relative sizes of DNSPs should not reduce the amount of funding for demand management.[884]

14.4 Submissions

The AER received submissions from the City of Sydney, EnergyAustralia, the Energy Users Association of Australia (EUAA), Integral Energy and the Total Environment Centre (TEC) on the application of a DMIS.

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879 EnergyAustralia, *Revised regulatory proposal*, p. 127.
880 EnergyAustralia, *Revised regulatory proposal*, p. 127.
881 EnergyAustralia, *Revised regulatory proposal*, p. 128.
882 EnergyAustralia, *Revised regulatory proposal*, p. 128.
883 Integral Energy, *Revised regulatory proposal*, p. 72.
884 Integral Energy, *Revised regulatory proposal*, p. 72.

14.4.1 City of Sydney

The City of Sydney's submission outlined its *Sustainable Sydney 2030* plan to reduce greenhouse gas emissions. It submitted that it considers the AER's role is to create an energy sector that can effectively minimise financial and environmental costs to consumers, by reducing the drivers behind energy consumption and peak load growth and fostering demand management. It urged the AER to enable, rather than obstruct, efforts by the City of Sydney, EnergyAustralia and others to address climate change and limit future costs to electricity consumers.[885]

The City of Sydney made a number of recommendations relating to demand management, including that the AER should:[886]

- report on the greenhouse gas emissions implications of the draft determination, particularly in relation to scenarios which include a greater proportion of demand management projects
- ensure that its determination facilitates major investment and innovation in demand management
- acknowledge that the determination covers a period in which greenhouse emissions must start to decline in order to achieve reduction targets
- clearly describe how its determination provides effective incentives for DNSPs to redirect expenditure towards measures which moderate growth in energy consumption
- explicitly state that it encourages DNSPs to redirect proposed network investment costs into more sustainable and cost effective means, such as demand management, whenever this represents a lower cost than network augmentation
- support open, competitive and transparent processes for identifying, procuring and implementing alternatives to network augmentation
- set targets for demand management outcomes, as done in California
- ensure that DNSPs report on demand management outcomes
- allow DNSPs to invest in demand management a year or two prior to expected network capacity constraints, to better manage risk and build better expertise in demand management
- commission robust and transparent assessment of the potential for cost effective demand management, based on international best practice.

14.4.2 EnergyAustralia

EnergyAustralia submitted that it supports the general direction of the DMIS outlined in the draft decision, however it would prefer the AER apply a broader and more meaningful incentive for innovation in demand management, particularly in a political climate of reducing energy use.[887]

[885] City of Sydney, pp. 1–2.
[886] City of Sydney, pp. 2–4.
[887] EnergyAustralia, *Further submission*, p. 13.

14.4.3 Energy Users Association of Australia

The EUAA submitted that it does not consider that the extension of the D–factor into the next regulatory control period will deliver substantially better outcomes than the modest achievements of the scheme to date.[888]

The EUAA also stated that the NSW DNSPs' DMIA funding should be provided only in line with transparent and quantifiable demand management programs, submitting that the scheme should require the DNSPs to work closely with end users, their representatives and other demand management providers to achieve robust outcomes.[889]

The EUAA submitted that neither the DNSPs' revised regulatory proposals nor the draft decision indicate that demand management will play a major role in improving the performance of the networks over the next regulatory control period. It recommended that the AER strengthen the role of demand management among the networks, and consider chairing a demand management steering group.[890]

14.4.4 Integral Energy

Integral Energy reiterated its position that a DMIA of $1 million per annum should apply to it instead of the proposed $0.6 million allowance.[891]

Integral Energy also sought clarification on three aspects of the replacement DMIA, relating to audited data requirements, inclusion of Integral Energy's critical peak pricing trial in the DMIA and recovery of foregone revenues.[892]

14.4.5 Total Environment Centre

The TEC indicated that it supports the concept of the DMIA, but stated that the size of the allowance is insufficient to stimulate significant new demand management. It recommended that the DMIA should be set at 5 per cent of the forecast capex allowance for each DNSP.[893] The TEC stated that it is not clear how DNSPs will distinguish between demand management carried out under the DMIA and that carried out as normal business practice.

The TEC recommended that the DMIA should operate on a use–it–or–lose–it basis, otherwise the DNSPs may be able to defer demand management spending indefinitely. It also recommended that the DMIA criteria include 'value of capital and operating expenditure avoided or deferred'.[894]

The TEC stated that DNSPs should be able to pass through foregone revenue costs resulting from all demand management projects, independent of any DMIS, in all jurisdictions where a weighted average price cap control mechanism is applied.[895]

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888 EUAA, p. 22.
889 EUAA, p. 22.
890 EUAA, p. 23.
891 Integral Energy, *Submission to the AER*, p. 25.
892 Integral Energy, *Submission to the AER*, pp. 25–26.
893 TEC, *Submission to AER, NSW/ACT distribution DMIA*, 16 February 2009, p. 2.
894 TEC, p. 4.
895 TEC, p. 4.

The TEC recommended that the AER adopt and further develop the *NSW Demand Management Code of Practice*, and apply the code to DNSPs on a national basis.[896] The TEC also recommended that the AER develop demand management reporting models for all DNSPs and TNSPs, similar to that required under the DMIA. It recommended that the AER issue an annual consolidated report on all non–network solutions investigated and implemented, including those that were unsuccessful.[897]

14.5 Issues and AER considerations

14.5.1 D–Factor scheme

14.5.1.1 AER draft decision

The AER's draft decision was to apply the D–factor scheme to the NSW DNSPs over the next regulatory control period, in the form applied by IPART over the current regulatory control period. The AER rejected EnergyAustralia's claim that forgone revenues associated with demand management projects implemented in the current regulatory control period should be recovered in the next regulatory control period under the D–factor scheme.[898]

14.5.1.2 AER considerations

Issues raised by EnergyAustralia

EnergyAustralia stated that the demand impacts of demand management projects carried out in the final two years of the current regulatory control period may not be incorporated in the demand forecasts for the next regulatory control period. EnergyAustralia claimed it should be allowed to recover foregone revenue associated with demand management projects implemented in the current regulatory control period under the D–factor scheme, in the next regulatory control period.[899]

The AER notes that EnergyAustralia included revised energy and maximum demand forecasts as part of its revised regulatory proposal. EnergyAustralia also provided an updated energy forecast in April 2009, which incorporated the latest available audited weighted average price cap (WAPC) sales data.[900] The AER understands that these revised forecasts incorporate the effects of any demand management programs carried out prior to 2009. The AER considers that, by December 2008, demand management projects to be carried out in the final six months of the current regulatory control period could have been planned and the demand implications accounted for in the revised forecasts. Accordingly, the AER maintains its draft decision that foregone revenues associated with demand management projects implemented in the current regulatory control period may not be recovered under the D–factor scheme in the next regulatory control period.

Issues raised by the Energy Users Association of Australia

The AER notes the EUAA's submission relating to the modest achievements of the D–factor to date. In its final decision on the application of demand management incentive

896 TEC, p. 3.
897 TEC, p. 5.
898 AER, *Draft decision*, p. 268.
899 EnergyAustralia, *Revised regulatory proposal*, p. 127.
900 EnergyAustralia, L*etter to the AER—revised January 2009 energy forecasts incorporating EnergyAustralia's comments on MMA report,* 9 April 2009.

schemes to the ACT and NSW DNSPs, published on 29 February 2008, the AER noted that the modest demand management results achieved to date under the D–factor indicate that the scheme may need more time to develop.[901] Consistent with the draft decision, the AER maintains its position that the D–factor should be applied for the next regulatory control period. The AER will continue to monitor the operation and results of the D–factor over the next regulatory control period, and will make its decision on the appropriateness of the scheme's application in the subsequent regulatory control period at the time of making its 2014 distribution determinations.

14.5.2 Demand management innovation allowance

14.5.2.1 AER draft decision

The draft decision, subject to the agreement of the NSW DNSPs (as the affected DNSPs), amended the DMIA published on 29 February 2008, by replacing it with the DMIA specified in *Demand management incentive scheme for the ACT and NSW distribution determinations* (the replacement DMIA).[902] The replacement DMIA was published concurrently with the draft decision.

14.5.2.2 AER considerations

Replacement of DMIA

Subsequent to submitting their revised regulatory proposals, Country Energy[903], EnergyAustralia[904] and Integral Energy[905] each provided their express agreement to amend the DMIA by replacing it with the replacement DMIA, which was published concurrently with the draft decision in November 2008.

Magnitude of allowance

The AER considered submissions from Country Energy, Integral Energy and the TEC regarding the magnitude of the DMIA. The AER also considered EnergyAustralia's statement that the allowance is too modest.[906]

The AER maintains its position that it is appropriate to base the DMIA allowances on the relative sizes of the NSW DNSPs' revenues, as it considers that the efficient level of demand management will vary according to the size of the network and potential for deferral of network augmentation by the DNSPs.

The AER considers that the allowance provided under the DMIA will provide a sufficient incentive for each DNSP to further develop their demand management initiatives and capabilities over the next regulatory control period.

The AER is required to consider the extent to which DNSPs have undertaken demand management where it is an efficient response to network constraints, as part of normal

901 AER, *Final Decision: DMIS*, p. 6.
902 AER, *Draft decision*, p. 268.
903 Country Energy, email to the AER, 19 February 2009.
904 The AER notes that EnergyAustralia supported the AER's decision to apply the replacement DMIA, subject to the AER providing clarification on the operation of the scheme, which is provided in section 14.5.2.2 of this final decision. EnergyAustralia, email to the AER re: Agreement on replacement DMIA, 6 March 2009.
905 Integral Energy, email to the AER, 19 February 2009.
906 EnergyAustralia, email to the AER re: Agreement on replacement DMIA, 6 March 2009.

business operations.[907] The DMIA is modest, recognising that it is provided in addition to demand management expenditures undertaken where they are efficient responses to network constraints. The DMIA is not a substitute for DNSPs' current expenditure on demand management, rather it builds upon the existing incentives to carry out demand management in the regulatory framework.

Issues raised by EnergyAustralia

The AER has again considered EnergyAustralia's recommendation that the DMIA should recognise the time value of money invested in innovation projects, consistent with the timing of investments within the PTRM. The AER considers that this would result in a significant increase in the demand management incentive generated by the DMIA. It would result in the effective double recovery of costs under the scheme, as DNSPs would receive the principal costs within the allowance, as well as having expenditure rolled into the regulatory asset base (RAB) in the subsequent regulatory control period.

The AER also reconsidered EnergyAustralia's submission that any unspent DMIA be rolled forward into the 2014–19 regulatory control period, and that the administration of the DMIA be allowed to continue into the 2019–24 regulatory control period until all funds are exhausted. As noted in the AER's draft decision, the AER considers these recommendations are not consistent with the objective of the DMIA, which is to provide a modest level of financial support to defray some of the start–up costs of demand management in the next regulatory control period and to advance the timing of demand management initiatives. The AER considers EnergyAustralia's suggestions may result in fewer demand management projects being undertaken in the next regulatory control period, as DNSPs would be able to delay planned projects into the 2014–19 regulatory control period, as highlighted by the TEC in its submission on the draft decision.

The AER cannot guarantee to continue the operation of either the DMIA or D–factor schemes beyond the end of the next regulatory control period, except to ensure that demand management projects implemented in the final two years of the next regulatory control period under the D–factor will be recoverable in the first two years of the subsequent regulatory control period, consistent with the lagged operation of that scheme.

In its further submission on the draft decision, EnergyAustralia broadly agreed to the application of the replacement DMIA for the next regulatory control period, subject to clarification about some aspects of the scheme's operation.[908] Subsequent to making its submission, EnergyAustralia requested clarification regarding whether capex incurred under the DMIA would be treated as capital contributions and whether capex over the DMIA cap would be incorporated into the RAB at the end of the next regulatory control period, subject to the provisions of schedule 6.2.1 of the NER.[909]

As set out in clause 6 of the DMIA, the AER considers that capex on DMIA projects should be treated as capital contributions under clause 6.21.1 of the transitional chapter 6 rules, and therefore not rolled into the RAB at the start of the subsequent regulatory control period.[910] While opex overspends associated with the DMIA will not be recovered

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907 NER, transitional chapter 6, clause 6.5.6(e)(10) and 6.5.7(e)(10).

908 EnergyAustralia, *Further submission*, p. 13.

909 EnergyAustralia, email to the AER re: Agreement on replacement DMIA, 6 March 2009.

910 AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme*, November 2008, clause 3.1.3(6).

from customers, capex overspends associated with the DMIA will be treated in the same manner as other capex overspends and therefore may be rolled into the RAB for the 2014–19 regulatory control period if the expenditure satisfies schedule 6.2 of the NER. However, the AER's decision on the RAB for the beginning of the 2014–19 regulatory control period will only be made at the time of its determinations for that regulatory control period.

EnergyAustralia also stated that it would be appropriate to allocate the DMIA allowance to opex first, and allocate any remaining allowance to capex. EnergyAustralia noted that the depreciated actual value of capex beyond the DMIA allowance would be rolled into the RAB at the start of the 2014–19 regulatory control period, if it satisfied schedule 6.2.1 of the transitional chapter 6 rules.[911]

The intention of allowing both capex and opex to be recovered under the DMIA was to provide DNSPs with maximum flexibility in selecting the demand management projects to carry out under the scheme. This is in recognition of the fact that demand management, while most often consisting of opex, can include elements of capex. DNSPs can decide how they wish to spend the DMIA, such that projects meet the DMIA criteria in section 3.1.3 of the DMIA scheme.[912] At the end of each regulatory year, the NSW DNSPs must submit a report outlining their expenditure under the DMIA to the AER. The NSW DNSPs' reports are to include details on the implementation costs associated with each demand management program/project, such as whether the expenditures are capital or operating. Section 3.1.4.1 of the DMIA sets out the requirements of these annual reports.[913]

The AER requires this information in order to calculate whether the cap has been exceeded in net present value terms. As such the AER does not consider that EnergyAustralia's proposal that the allowance be allocated to opex first is consistent with the operation of the scheme.

The AER notes that the DMIA is not intended to replace or substitute for demand management initiatives currently being carried out as part of a DNSP's normal operations, and is applied in addition to the obligations on DNSPs to consider non–network alternatives to capex or opex imposed by the NER.

Issues raised by Integral Energy

Integral Energy queried whether the requirement for audited data within the DMIA is in reference to audited WAPC data.[914] The AER confirms that footnote 2 in section 3.1.4 on page 5 of the AER's replacement DMIA[915] refers to audited WAPC data, provided to the AER on an annual basis.

Integral Energy also queried whether the implementation of its direct load control programs, involving equipment being installed on customers' appliances, which also have

911 EnergyAustralia, email to the AER re: Agreement on replacement DMIA, 6 March 2009.

912 AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme*, November 2008, clause 3.1.3.

913 AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme*, November 2008, pp. 5–6.

914 Integral Energy, *Submission to the AER*, p. 25.

915 AER, *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme*, November 2008.

a tariff component associated with them would be classified as tariff or non–tariff based demand management projects under the replacement DMIA.[916] In principle, the AER considers that such demand management projects would be considered tariff based in the context of the DMIA, and therefore would only be eligible for implementation cost recovery under the scheme, not foregone revenue costs.[917] This is because the AER considers that higher customer prices associated with such a project would offset reductions in electricity sales.

Integral Energy also queried whether foregone revenues associated with demand management projects would be recoverable under the D–factor scheme.[918] The AER will apply the D–factor to the NSW DNSPs in the next regulatory control period, in the form applied by IPART in the current regulatory control period. The D–factor scheme allows for the recovery of foregone revenues as a result of implementing non–tariff based demand management projects or programs.[919] The AER will not allow for the recovery of foregone revenue resulting from demand management projects or programs carried out independently of the DMIS, that is, outside the D–factor and DMIA schemes. The AER notes that it will only allow the recovery of foregone revenues under the DMIA that are associated with non–tariff based demand management projects approved under the DMIA. Likewise, the AER will only allow the recovery of foregone revenues under the D–factor that are associated with non–tariff based demand management projects approved under the D–factor.

Other issues and recommendations

The TEC recommended that the DMIA should operate on a use–it–or–lose–it basis, otherwise the DNSPs' may be able to defer demand management spending indefinitely.[920] The AER notes that this recommendation was taken up in the design of the AER's replacement DMIA, and that all allowances under the scheme are provided ex ante, on a use–it–or–lose–it basis.

The TEC also recommended that the DMIA criteria include 'value of capital and operating expenditure avoided or deferred,' while the EUAA called for the DMIA to be provided only in line with quantifiable demand management programs.[921] The AER considers that this requirement is counter to the objective of the DMIA, which is to provide a modest allowance for innovative, untested demand management projects that may not result in direct and quantifiable deferrals of capex in the short term, but may provide dynamic network benefits over the long term. The AER notes that the D–factor scheme requires that demand management programs must result in a direct, quantifiable avoidance of distribution costs in order for compensation to be provided.

The TEC stated that it is not clear how DNSPs will distinguish between demand management carried out under the DMIA and that carried out as normal business practice, and raised its concern that DNSPs may be able to recover demand management projects twice.[922] Criterion 5(c) of the DMIA requires that costs recovered under the scheme must not be included in forecast capital or operating expenditure approved in the distribution

916 Integral Energy, *Submission to the AER*, p. 25.
917 AER, *Replacement DMIA*, p. 8.
918 Integral Energy, *Submission to the AER*, p. 26.
919 AER, *Final decision DMIS*, 29 January 2008, appendix B, p. 2.
920 TEC, p. 3.
921 TEC, p. 4 ; and EUAA, p. 22.
922 TEC, p. 3.

determination for the next regulatory control period, or under any other incentive scheme in that determination.[923] The AER considers that this precludes DNSPs from submitting for recovery of costs of demand management projects under the DMIA that have also been funded under the broader capex and opex allowances.

The EUAA submitted that the DMIA should require the DNSPs to work closely with end users, their representatives and other demand management providers to achieve robust outcomes.[924] The DMIA criteria aims to provide DNSPs with a certain level of autonomy in electing how to carry out demand management projects, such that the expenditure is not constrained by specific requirements. The AER notes that the NSW DNSPs may elect to involve any number of parties in their demand management programs that are funded under the DMIA.

14.5.3 General demand management issues

Environmental policies

The AER notes the recommendations made by the City of Sydney relating to the greenhouse gas implications of the AER's determination.

The AER is an economic regulator, limited in its role to applying and enforcing the NER. The NER provides some scope for the AER to develop and apply incentives for DNSPs to consider demand management, however only where demand management is the most economically efficient response to a network constraint.

The AER is aware that there are a number of climate change policies currently being discussed, which could have wide spread implications for DNSPs and the NEM. In developing its DMIS, the AER considered the potential impact of these policies on DNSPs' incentives to carry out demand management. While it takes into account the policy environment in which its decisions are made, including environmental policies and debates, the NER requires that the AER creates incentives for the DNSPs to make economically efficient business decisions, rather than decisions which preference environmentally efficient outcomes.

The DMIS will create incentives for DNSPs to consider innovative ways to manage demand on their networks, and to apply the innovative solutions where they are an economically efficient response to network constraints. This is likely to result in positive environmental externalities.

Demand management in the draft decision

The AER notes the EUAA's concern that demand management will not play a major role in improving the performance of the networks over the next regulatory control period, and its recommendation that the AER consider chairing a demand management steering group.[925] The AER also notes EnergyAustralia's recommendation that the AER should apply a broader and more meaningful incentive for innovation in demand management[926],

[923] AER, *Replacement DMIA*, p. 5.
[924] EUAA, p. 22.
[925] EUAA, p. 23.
[926] EnergyAustralia, *Further submission*, p. 13.

and the TEC's recommendation that the AER should adopt and further develop the *NSW Demand Management Code of Practice*.[927]

The AER has also considered the City of Sydney's recommendations that the AER's final determination should facilitate major investment and innovation in demand management, and that the AER should commission a robust and transparent assessment of the potential for cost effective demand management, based on international best practice.[928] The City of Sydney also stated that the AER should clearly describe how its determination provides effective incentives for DNSPs to redirect expenditure towards measures which moderate growth in energy consumption.[929]

The regulatory framework is designed such that DNSPs are obliged to undertake demand management where it is an efficient response to a network constraint, and as part of normal business operations. Demand management measures are typically aimed at reducing peak demand on the network, however they may also reduce growth in energy consumption at off peak times.

In determining the appropriate amount of capex and opex for each of the NSW DNSPs over the next regulatory control period, the AER has considered the extent that the NSW DNSPs have considered and made provision for, efficient non–network alternatives, as required by clauses 6.5.6(e)(10) and 6.5.7(e)(10) of the transitional chapter 6 rules. In addition, the AER has decided to apply a DMIS to the NSW DNSPs for the next regulatory control period, to provide direct financial incentives for DNSPs to implement demand management activities that would not otherwise have occured. In particular, the DMIA will provide DNSPs with funding for innovative, untested demand management projects that aim to provide dynamic, long–term benefits for the network user. The AER has considered the level of demand management incentives present in the regulatory framework, as well as potential impacts of the wide number of climate change policies currently being considered by various governments, and considers that there is likely to be sufficient scope for DNSPs to carry out demand management in the next regulatory control period, where it is an efficient response to network constraints.

Clause 6.16(d) of the NER (that is, the general chapter 6 rules) provides that the AER may publish issues, consultation and discussion papers, and hold conferences and information sessions in relation to DMIS. While not directly relevant to the AER's final decision on DMIS for the NSW DNSPs, the AER will consider whether it is appropriate for it to facilitate a more general discussion forum, engaging various industry sectors, for the ongoing development of DMIS. The AER notes that the AEMC is currently undertaking a review on the potential for NER changes to better facilitate demand side participation in the NEM. Further details on this review are available on the AEMC's website.[930]

Issues raised by the Total Environment Centre

The TEC submitted that DNSPs should be able to recover the costs of foregone revenue resulting from demand management projects carried out as part of normal business, as well as that carried out under the DMIA. The TEC stated that this recommendation

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927 TEC, p. 3.
928 City of Sydney, p. 3.
929 City of Sydney, p. 3.
930 See <http://www.aemc.gov.au/electricity.php?r=20071025.174223>

applies to demand management in all jurisdictions where the WAPC control mechanism is applied.[931]

The NER requires that in developing and applying a DMIS, the AER must have regard to the need to ensure that benefits to consumers likely to result from the DMIS are sufficient to warrant any reward or penalty under the scheme for DNSPs.[932] As noted above, the AER has considered the existing level of incentives for demand management in the design of its DMIA. The AER considers the incentive for the NSW DNSPs to conduct demand management created by the DMIS is appropriate for the next regulatory control period recognising that the regulatory framework provides incentives for efficient demand management.

The TEC recommended that the AER develop demand management reporting models for all DNSPs and TNSPs, based on the reporting requirements of the DMIA. It also recommended that the AER issue an annual consolidated report on all non–network solutions investigated and implemented, including those that were unsuccessful.[933]

The AER is currently developing annual reporting guidelines for DNSPs, in the form of a regulatory information order (RIO). In August 2008 the AER released an issues paper on the development of a RIO for all DNSPs in the NEM.[934] The AER intends to release a draft RIO in mid 2009, for comment by interested parties. Information proposed to be sought and made public includes demand management programs and expenditures.

Issues raised by the City of Sydney

The City of Sydney recommended that the AER ensure that DNSPs report on demand management outcomes.[935] The AER's DMIS for NSW DNSPs, consisting of the DMIA and D–factor schemes, requires DNSPs to report on the outcomes of demand management projects in order to be eligible for demand management cost recovery under those schemes.

The City of Sydney also recommended that the AER:[936]

- allow DNSPs to invest in demand management prior to expected network capacity constraints
- support open, competitive and transparent processes for identifying, procuring and implementing alternatives to network augmentation, and
- explicitly state that it encourages DNSPs to redirect proposed network investment costs into more sustainable and cost effective means, such as demand management, whenever this represents a lower cost than network augmentation.

The NER requires that DNSPs consider alternatives to network augmentation, including demand management, when determining potential responses to network constraints.[937]

931 TEC, p. 3.
932 NER, transitional chapter 6 rules, clause 6.6.3(b)(1).
933 TEC, p. 5.
934 AER, *Issues paper—Electricity distribution network service providers—Annual information reporting requirements*, August 2008.
935 City of Sydney, p. 3.
936 City of Sydney, pp. 3–4.
937 NER, transitional chapter 6 rules, clauses 6.5.6(e)(10) and 6.5.7(e)(10).

The AER's approval of an efficient allowance for capex and opex does not limit a DNSP's operational independence to best manage their network, including in making decisions to trade network augmentation for efficient demand management. As noted above, the AER is currently developing a RIO for DNSPs, which is proposed to include public reporting on demand management programs and expenditures.

The City of Sydney recommended that the AER set targets for demand management outcomes, as done in California. The AER has previously considered the differences between its role and the role of the California Public Utilities Commission in relation to demand management.[938] The recommendations made by the City of Sydney in relation to California refer to broader policy decisions which go beyond the AER's responsibilities in respect of applying chapter 6 of the NER to the NSW DNSPs.

14.6 AER conclusion

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

The AER's decision is to amend the DMIA applied in its final decision on DMIS, released on 29 February 2008, by replacing it with the replacement DMIA, as published by the AER on 28 November 2008.

The demand management incentive scheme to apply to the NSW DNSPs is the DMIA set out in the AER's *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme*, November 2008.

In accordance with clause 6.3.2(a)(3) of the transitional chapter 6 rules the application of the demand management incentive scheme to apply to the NSW DNSPs is as specified in this section 14.6.

938 AER, *Explanatory statement and proposed demand management incentive scheme to apply to Energex, Ergon Energy and ETSA Utilities over the 2010–15 regulatory control period*, June 2008, pp. 19-20 and AER, *Final decision—demand management incentive scheme—Energex, Ergon Energy and ETSA Utilities, 2010–15*, October 2008, p. 16.

14.7 AER decision

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the demand management incentive scheme to apply to Country Energy is the DMIA set out in the AER's *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme*, November 2008, and the D–factor scheme set out in IPART's *Guidelines on the Application of the D–factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination.*

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the demand management incentive scheme to apply to EnergyAustralia is the DMIA set out in the AER's *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme*, November 2008, and the D–factor scheme set out in IPART's *Guidelines on the Application of the D–factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination.*

In accordance with clause 6.12.1(9) of the transitional chapter 6 rules the demand management incentive scheme to apply to Integral Energy is the DMIA set out in the AER's *Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme*, November 2008, and the D–factor scheme set out in IPART's *Guidelines on the Application of the D–factor in the Tribunal's 2004 NSW Electricity Distribution Pricing Determination.*

15 Pass through arrangements

15.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision and the AER's assessment of the NSW DNSPs' proposed pass through events to apply during the next regulatory control period.

The pass through provisions of the transitional chapter 6 rules allow material changes (both increases and decreases), in the costs of providing direct control services to be passed through to distribution network users during a regulatory control period. In order for costs to be passed through, a 'pass through event' must occur.

The NER defines specific events that constitute pass through events. In addition to these defined events, the transitional chapter 6 rules provide that the AER may nominate events in its distribution determination that will constitute pass through events for the next regulatory control period.[939]

15.2 AER draft decision

In the draft decision the AER accepted a retail project event and force majeure event as nominated pass through events for the NSW DNSPs.[940] The AER did not consider that the other proposed pass through events met the AER's assessment criteria and therefore it did not accept those events as nominated pass through events. The draft decision did not define a materiality threshold for pass through events.

15.3 NSW DNSP revised regulatory proposals

15.3.1 Country Energy

Country Energy accepted some aspects of the draft decision but it did not accept other aspects. Country Energy proposed in its revised regulatory proposal that the following events be nominated as pass through events:[941]

- changes in risk assessment costs due to court cases and other legal obligations
- certain events the AER had suggested would be regulatory change events, specifically:
  - the introduction of smart meters
  - retailer of last resort
  - the introduction of an emissions trading scheme
- electric and magnetic field uninsurable events
- earthquakes greater than magnitude five

[939] See definition of 'pass through event' in chapter 10 of the NER
[940] AER, *Draft decision*, pp. 286–287.
[941] Country Energy, *Revised regulatory proposal*, pp. 63–66.

- an insurance event, defined as:

> An insurance event is an event for which the risk of its occurrence is the subject of insurance taken out by or for a Distribution Network Service Provider, for which an allowance is provided in the total revenue requirements for the DNSP and in respect of which:
>
> (a) the cost of the premium paid or required to be paid by the DNSP in the regulatory year in which the cost of the premium changes is higher or lower than the premium that is provided for in the revenue requirement for the DNSP for that regulatory year by an amount of more than the materiality threshold applying to the DNSP for a pass through event for that regulatory year;
>
> (b) the risk eventuates and, as a consequence, the DNSP incurs or will incur all or part of a deductible where the amount so incurred or to be so incurred in a regulatory year is higher or lower than the allowance for the deductible (if any) that is provided for in the revenue requirements for the DNSP for that regulatory year by an amount of more than the materiality threshold applying to the DNSP for a pass through event for that regulatory year;
>
> (c) insurance becomes unavailable to the DNSP; or
>
> (d) insurance becomes available to the DNSP on terms materially different to those existing as at the time the regulatory determination was made (other than as a result of any act or omission of the provider which is inconsistent with good electricity industry practice)

Earthquakes greater than magnitude five events and the insurance event proposed in the revised regulatory proposal, were not included in Country Energy's regulatory proposal (submitted in June 2008). Earthquakes of greater than magnitude five events were proposed in response to the draft decision to reject a proposed self insurance allowance for such an event.

The electric and magnetic fields event was amended from that in the regulatory proposal. The amendment excluded insurable claims, and was made in response to the draft decision that rejected the event on the basis that third party claims are insurable.[942]

15.3.2 EnergyAustralia

EnergyAustralia did not accept any aspect of the draft decision with respect to pass through events. EnergyAustralia maintained the position in its regulatory proposal (submitted in June 2008), and proposed seven events to be nominated as pass through events. Full definitions of the proposed events are contained in attachment 15.1 to EnergyAustralia's revised regulatory proposal. [943] These events, summarised in EnergyAustralia's June 2008 regulatory proposal, are reproduced below:[944]

> **Dead zone event:** any pass through event that occurs during the 2004-2009 regulatory control period that has a cost impact in the 2009-2014 regulatory control period, that has not been included in EnergyAustralia expenditure forecasts (as accepted or substituted by the AER) for that period.
>
> **Force majeure event:** any fire, flood, earthquake, storm or other weather-related event or natural disaster, act of God, riot, civil disorder or rebellion or other

942 Country Energy, *Revised regulatory proposal*, pp. 64–65.
943 EnergyAustralia, *Revised regulatory proposal*, p. 129.
944 EnergyAustralia, *Regulatory proposal*, pp. 162–165.

similar cause beyond the reasonable control of EnergyAustralia that occurs during a regulatory control period and materially increases the cost to EnergyAustralia of providing Standard Control Services including Prescribed (Transmission) Standard Control Services.

Cost or demand input variance event: an event involving any change in actual cost movements or demand during the regulatory control period from cost movements or demand forecasts used in EnergyAustralia's expenditure forecasts (as accepted or substituted by the AER) that materially increases or decreases the cost to EnergyAustralia of providing Standard Control Services including Prescribed (Transmission) Standard Control Services.

Joint planning event: an event involving a change to a capital project the subject of joint planning between EnergyAustralia and TransGrid, or EnergyAustralia and another NSW DNSP, or a new project relevant to joint planning that is beyond EnergyAustralia's reasonable control and materially increases or decreases the costs to EnergyAustralia of providing Standard Control Services including Prescribed (Transmission) Standard Control Services.

Compliance event: an event other than a service standard event or a regulatory change event involving:

- a change in a compliance obligation (meaning a general law obligation or a requirement of a non-mandatory code, standard or guideline which represents standards acceptable to the workforce or to the community); or

- a change in the way a compliance obligation is interpreted; or

- any new compliance obligation, which materially increases or decreases the cost to EnergyAustralia of providing Standard Control Services including Prescribed (Transmission) Standard Control Services.

Customer connection event: a transmission or subtransmission network connection for a developer, an end-use customer or a generator, or a requirement for EnergyAustralia to establish a new substation to supply load requested by a developer or end-use customer that materially increases or decreases the costs, relative to those allowed in the proposal, to EnergyAustralia of providing Standard Control Services including Prescribed (Transmission) Standard Control Services.

Separation event: any legislative or administrative act or decision to separate any business or function of EnergyAustralia in whole or in part from any other business or function of EnergyAustralia, which materially increases or decreases the costs to EnergyAustralia of providing Standard Control Services, including EnergyAustralia Prescribed (Transmission) Standard Control Services.

The retail project event and force majeure event that the AER accepted in the draft decision were similar in meaning to the separation event and force majeure event proposed by EnergyAustralia, although the definitions of the events differed.[945] EnergyAustralia did not consider that those events as defined by the AER adequately reflected the definitions it had proposed and therefore reiterated its proposed definitions in its revised regulatory proposal.[946]

945 AER, *Draft decision*, pp. 286–287 and EnergyAustralia, *Regulatory proposal*, pp. 163, 165.
946 EnergyAustralia, *Revised regulatory proposal*, pp. 144–145.

15.3.3 Integral Energy

Integral Energy accepted some aspects of the draft decision but it did not accept other aspects. Integral Energy proposed in its revised regulatory proposal that the following events be nominated as pass through events:[947]

> **automated interval meters event:** an event which results in Integral Energy being required to install automated interval meters (otherwise known as smart meters) for some or all of its customers or to conduct large scale metering trials during the course of the regulatory control period, regardless of whether that requirement takes the form of the imposition of a statutory obligation or not, and which:
>
> (a) falls within no other category of pass through event; and
>
> (b) increases the costs of Integral Energy providing the direct control services.
>
> **change in reporting requirements event:** an event which results in the imposition of additional reporting requirements on Integral Energy as a Distribution Network Service Provider to the Australian Energy Regulator or any other regulator which:
>
> (a) occurs during the regulatory control period;
>
> (b) falls within no other category of pass through event; and
>
> (c) materially increases the costs of Integral Energy providing the direct control services.
>
> **distribution loss event:** an event which results in the imposition of costs or legal obligations on Integral Energy in relation to distribution losses from the operation of its distribution network which:
>
> (a) occurs during the regulatory control period;
>
> (b) falls within no other category of pass through event; and
>
> (c) materially increases the costs of Integral Energy providing the direct control services.
>
> **electric and magnetic fields event:** during the course of the regulatory control period either of the following types of events occur:
>
> (a) Integral Energy becomes liable for any claim for the diminution in the value of property where the claim is directly related to electric and magnetic fields from any of the assets it owns and operates or has owned and operated including claims by present and former employees of Integral Energy and/or third parties; or
>
> (b) The manner in which Integral Energy undertakes 'live-line' work is affected due to the potential exposure of the people undertaking this work to electric and magnetic fields
>
> and as a consequence of that event, the costs to Integral Energy of providing direct control services are materially increased.

[947] Integral Energy, *Regulatory proposal to the AER 2009 to 2014*, 2 June 2008, pp. 184–186; and Integral Energy, *Revised regulatory proposal*, pp. 75–81.

emissions trading scheme event: an event which results in the imposition of legal obligations on Integral Energy arising from the introduction or operation of a carbon emissions trading scheme by the Commonwealth during the course of the regulatory control period and which:

(a) falls within no other category of pass through event; and

(b) materially increases the costs of Integral Energy providing the direct control services.

functional change event: an event which results in the imposition of new obligations, or changes the nature of the existing obligations, on Integral Energy as a Distribution Network Service Provider which:

(a) occurs during the regulatory control period;

(b) falls within no other category of pass through event; and

(c) materially increases the costs of Integral Energy providing the direct control services.

retailer of last resort event: an event which results in the imposition of costs or legal obligations on Integral Energy relating to the Retailer of Last Resort scheme under the Electricity Supply Act 1995 (NSW) and which event:

(a) occurs during the regulatory control period;

(b) falls within no other category of pass through event; and

(c) materially increases the costs of Integral Energy providing the direct control services

insurance event: An event for which the risk of its occurrence is the subject of insurance taken out by or for a Distribution Network Service Provider, for which an allowance is provided in the weighted average price cap for the Distribution Network Service Provider and in respect of which:

(a) the cost of the premium paid or required to be paid by the Distribution Network Service Provider in the regulatory year in which the cost of the premium changes is higher or lower than the premium that is provided for in the annual revenue requirement for the provider for that regulatory year by an amount of more than 1% of the annual revenue requirement for the provider for that regulatory year;

(b) the risk eventuates and, as a consequence, the Distribution Network Service Provider incurs or will incur all or part of a deductible where the amount so incurred or to be so incurred in a regulatory year is higher or lower than the allowance for the deductible (if any) that is provided for in the annual revenue requirement for the provider for that regulatory year by an amount of more than 1% of the annual revenue requirement for the provider for that regulatory year;

(c) insurance becomes unavailable to the Distribution Network Service Provider; or

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

The insurance event was not proposed by Integral Energy in its regulatory proposal (submitted in June 2008). It was proposed in response to the draft decision not to nominate sabotage, asbestos and gradual pollution events as pass through events on the grounds that they are all events which can be insured against.[948]

The electric and magnetic fields event in the revised regulatory proposal was amended from that in the regulatory proposal to take into account the draft decision, which noted that third party claims could be insured against.[949]

The automated interval meters event in the revised regulatory proposal was amended from that in the regulatory proposal by removing the reference to a 'material' increase in costs that appeared in the regulatory proposal.

15.4 Submissions

15.4.1 Country Energy

Country Energy stated:

- **Smart meter, retailer of last resort and emissions trading scheme events** — the AER should positively confirm that it would treat these events as regulatory change events if they occur. In the absence of such confirmation, Country Energy submitted the events should be nominated as pass through events.[950]
- **Electric and magnetic fields uninsurable events** — Country Energy accepted that the implementation of a draft standard prepared by the Australian Radiation Protection and Nuclear Safety Agency could be considered a regulatory change event. Country Energy submitted that its insurance coverage for electric and magnetic field events only covers physical damage to third party property, and amended its definition to exclude insurable events.[951]
- **Materiality** — the AER should define a materiality threshold in the determination. A reasonable starting point would be to align it with the materiality threshold for a transmission pass through event. The AER should consider setting a lower materiality threshold for events triggered by asymmetric risks such as terrorism events.[952]

15.4.2 EnergyAustralia

EnergyAustralia applied each of the criteria identified in the draft decision to several of its proposed events. EnergyAustralia submitted that the criteria were satisfied for each event, and therefore the events should be nominated as pass through events.[953]

Some of the arguments raised by EnergyAustralia related to several of its proposed events. EnergyAustralia argued:

- the AER rejected events in the draft decision which meet the AER's stated criteria for assessing nominated events[954]

[948] Integral Energy, *Revised regulatory proposal*, p. 80.
[949] Integral Energy, *Revised regulatory proposal*, p. 77.
[950] Country Energy, *Revised regulatory proposal*, p. 64.
[951] Country Energy, *Revised regulatory proposal*, pp. 64–65.
[952] Country Energy, *Revised Regulatory proposal*, p. 65.
[953] EnergyAustralia, *Revised regulatory proposal*, pp. 136, 138–139, 141, 142–143, 144.

- the AER misapplied the relevant provisions of the transitional chapter 6 rules and acted unreasonably[955]
- the AER inappropriately relied on Wilson Cook's opinion in contravention of the legal principles underlying the admissibility of expert evidence[956]
- EnergyAustralia's incentives to oppose proposals by third parties (such as mandating smart meters) that could result in inefficient costs would not be diminished by allowing pass through events in regards to those proposals[957]
- the AER should apply pass throughs to alternative control services as well as standard control services.[958]

EnergyAustralia also commented on the draft decision with respect to specific proposed events:

- **Compliance event** — this event should be permitted because the event is uncontrollable and because EnergyAustralia has no discretion as to whether or not it complies with the law and other obligations.[959]
- **Customer connection event** — these events are out of EnergyAustralia's control, unforeseen and are not discretionary and therefore do not undermine the incentive arrangements within the regulatory regime.[960] EnergyAustralia indicated in a further submission that, since finalising area plans and submitting them to the AER as part of its capex forecasts, there have been developments with respect to several major customer projects on the fringes of the Sydney CBD, and it now seems likely that several major customer projects that were not included in the capex forecasts are likely to proceed in the next regulatory control period. EnergyAustralia considered that these are firm proposals, and offered to provide further details to the AER on a confidential basis.[961] EnergyAustralia suggested that the City of Sydney's plans for tri–generation is a further example of why the AER should accept the proposed pass through event.[962]
- **Joint planning event** — the inclusion of this pass through event as a nominated event would ensure that the risk is borne by the most appropriate person. Furthermore such events are non–discretionary and uncontrollable and without such a pass through event, DNSPs seeking to alter a project for efficiency reasons may be penalised as a consequence.[963]
- **Cost or demand variance event** — EnergyAustralia noted that the draft decision rejected the event on the basis that allowing pass throughs for variations to normal business costs would undermine incentives to produce robust estimates and minimise costs. EnergyAustralia noted that the proposed event only applies where a variance

954 EnergyAustralia, *Revised regulatory proposal*, pp. 129–131.
955 EnergyAustralia, *Revised regulatory proposal*, p. 130.
956 EnergyAustralia, *Revised regulatory proposal*, pp. 131–132.
957 EnergyAustralia, *Revised regulatory proposal*, pp. 132–134.
958 EnergyAustralia, *Revised regulatory proposal*, p. 15.
959 EnergyAustralia, *Revised regulatory proposal*, pp. 135–136.
960 EnergyAustralia, *Revised regulatory proposal*, pp. 139–141.
961 EnergyAustralia, *Further submission*, p. 15.
962 EnergyAustralia, *Response to stakeholder submissions*, p. 28.
963 EnergyAustralia, *Revised regulatory proposal*, pp. 141–143.

has a 'material' impact on costs, and accordingly does not apply in circumstances involving variations to normal business costs and demand.[964]

- **Dead zone event** — EnergyAustralia submitted that it is not possible to delay submission of a pass through application, as suggested by the AER, because the rules do not provide any mechanism for doing so. It considered that if an event occurs during the current regulatory control period but its cost impact is in the next regulatory control period, it will not be caught by any of these pass through event definitions.[965]
- **Force majeure** — EnergyAustralia considered the AER's amended definition of force majeure was not adequate. It considered that the reference to 'events for which external or self–insurance is feasible' is problematic because:[966]
  - it creates a lack of clarity as to the meaning of 'feasible in this context', and
  - where the AER rejected a self insurance claim on the basis of the robustness of EnergyAustralia's calculation as to the likelihood of occurrence of the event in question, it should be recoverable under the force majeure pass through provisions.
- **Retail project event** — the AER definition does not capture everything that was included in EnergyAustralia's definition. The AER drafting of retail project event refers to a material change in the costs to the DNSP of 'providing direct control services in the next regulatory control period'. EnergyAustralia stated that the effect of this is that DNSPs could only potentially recover increased costs incurred in providing direct control services in the 2014–19 regulatory control period.[967]

15.4.3 Integral Energy

Integral Energy reiterated its claims that the proposed pass through events should be approved. Integral Energy stated:

- The proposed nominated events are defined to exclude events that fall into other categories, and therefore cannot meet the criteria of an event already being captured by defined events.[968]
- **Emissions trading scheme event** — Integral Energy referred to a statement from the Ministerial Council on Energy (MCE) stressing the importance of addressing regulatory impediments to carbon cost pass through and the importance of the national commitment to the pass through of carbon prices to end–use consumers.[969]
- **Automated interval meter event** — this event would not qualify as a regulatory change event and Integral Energy's incentives would not be altered if this event were accepted. Integral Energy proposed that a materiality threshold for this event to be set at zero.[970]

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964 EnergyAustralia, *Revised regulatory proposal*, pp. 143–144.
965 EnergyAustralia, *Revised regulatory proposal*, pp. 137–139.
966 EnergyAustralia, *Revised regulatory proposal*, p. 145.
967 EnergyAustralia, *Revised regulatory proposal*, p. 145.
968 Integral Energy, *Submission to the AER*, p. 17–18.
969 Integral Energy, *Submission to the AER*, p. 18.
970 Integral Energy, *Revised regulatory proposal*, p. 75.

- **Electric and magnetic fields event** — Integral Energy excluded third party claims from the definition in response to the AER draft decision which rejected the event because, among other things, third party claims were insurable.[971]
- **Functional change event** —– Integral Energy queried why the AER considers the intent of the NER is to limit pass through events to specific major unforeseen events only. It submitted that a DNSP often has little to no management discretion in regards to the imposition of new obligations which often arise under such an event. Integral Energy therefore argued that this event is not controllable.[972]
- **Insurance event** — in the draft decision the AER rejected Integral Energy's nominated pass through events in regards to asbestos, gradual pollution and sabotage on the grounds that such events are insurable.[973] In response, Integral Energy proposed an insurance event to cover a situation where the costs of insurance premiums change materially or insurance becomes unavailable.[974]
- **Federal government's stimulus package** — Integral Energy considered that additional costs incurred as a result of the federal government's stimulus package should be treated as regulatory change events.[975]
- **Materiality** — Integral Energy noted the AER's preliminary position on materiality, and proposed a materiality threshold of zero for an automated interval metering event to ensure trials can be undertaken with no incentive to introduce larger or smaller trials than necessary to ensure the government's policy objective can be delivered efficiently.[976]

15.4.4 Energy Users Association of Australia

The Energy Users Association of Australia (EUAA) requested that the AER not accept the retail project event as a nominated pass through event. It considered that the costs associated with the separation of retail and distribution businesses should be funded out of the sale proceeds received by the NSW Government received from the privatisation and not by end users.[977]

The EUAA requested that the AER continue to strenuously assess the validity of the insurance event pass through event and the redefined pass through events.[978]

15.5 Issues and AER considerations

15.5.1 Factors relevant to whether an event should be a nominated event

Provisions of the NEL and NER

The transitional chapter 6 rules provide that the AER may nominate events in its determination that will constitute pass through events for the next regulatory control

971 Integral Energy, *Revised regulatory proposal*, p. 77.
972 Integral Energy, *Revised regulatory proposal*, pp. 78–79.
973 AER, *Draft decision*, pp. 282–284.
974 Integral Energy, *Submission to the AER*, pp. 80–81.
975 Integral Energy, *Submission to the AER*, p. 18.
976 Integral Energy, *Revised regulatory proposal*, p. 76.
977 EUAA, pp. 24–25.
978 EUAA, p. 25.

period. Neither the NEL nor the NER provide any direct guidance to the AER on the matters it should take into account in deciding which events should be accepted as nominated pass through events. Guiding principles in the NEL and the general structure of the incentive regime, however, provide indirect guidance to the AER.

In support of their proposals for the inclusion of cost pass through events, the NSW DNSPs referred to the revenue and pricing principles in section 7A (2) of the NEL which provides:[979]

> (2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in-
>
> (a) providing direct control network services; and
>
> (b) complying with a regulatory obligation or requirement or making a regulatory payment.

The requirement to provide a reasonable opportunity for the NSW DNSPs to recover at least the efficient costs of providing direct control network services and complying with regulatory obligations must be balanced against the need to provide effective incentives required under paragraph 3 of section 7A (3) in the NEL:

> (3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes-
>
> (a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and
>
> (b) the efficient provision of electricity network services; and
>
> (c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

A pass through provides an opportunity to recover efficient costs that could not reasonably be accounted for in the distribution determination. It is limited in its application as it has the potential to undermine the incentive to effectively manage network risk in a least cost manner.

The transitional chapter 6 rules provide that the NSW DNSPs are granted allowances for total capital and operating expenditure programs for the next regulatory control period.[980] The AER does not approve allowances for individual projects or individual cost items; NSW DNSPs have discretion to manage the total expenditure allowances. This means that a NSW DNSP is free to spend an allowance in the manner it sees fit. If costs associated with a particular activity increase, a NSW DNSP may spend more of its allowance on that activity than was contemplated at the time of its regulatory proposal. Similarly, a NSW DNSP may spend less of its allowance on a particular activity if the costs associated with that activity turn out to be less than the forecast provided at the time

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979 Country Energy, *Revised regulatory proposal*, p. 64; EnergyAustralia, *Revised regulatory proposal*, p. 130 and Integral Energy, *Revised regulatory proposal*, p. 78.

980 Clauses 6.5.6 and 6.5.7 of the transitional chapter 6 rules refer to 'total' expenditure for the regulatory control period.

of the regulatory proposal. This flexibility allows NSW DNSPs to revise their expenditure priorities as circumstances change in the ordinary course of business over time.

In deciding what types of events should be pass through events, the AER must balance the requirement to allow NSW DNSPs the opportunity to recover at least efficient costs, with the requirement to ensure that DNSPs are provided with effective incentives to manage their expenditure.

Relevant factors for nominating events as pass through events

The AER's draft decision listed eight assessment criteria as factors to which the AER will have regard in determining whether an event should be nominated as a pass through event:[981]

- the event is already captured by the defined event definitions
- the event is clearly identified
- the event is uncontrollable. That is, a prudent service provider through its actions could not have reasonably prevented or substantially mitigated the event
- despite the event being foreseeable, the timing and/or cost impact of the event could not be reasonably forecast by the DNSP at the time of submitting its regulatory proposal
- the event is not already insured against (either external or self insured)
- the event cannot be self-insured because a self insurance premium cannot be calculated or the potential loss to the relevant DNSP is catastrophic
- the party who is in the best position to manage the risk is bearing the risk
- the passing through of the costs associated with the event would undermine the incentive arrangements within the regulatory regime.

No issues were raised in the revised regulatory proposals from the NSW DNSPs or in submissions regarding the use of these criteria to make a decision as to whether a proposed event should be a pass through event, although EnergyAustralia suggested that in some cases, the AER made errors of fact in applying the criteria to the proposed events.[982]

The AER has further considered the above criteria. The fourth criterion relates to foreseeability of an event. Both foreseeable and unforeseeable events have the potential to materially impact on a NSW DNSP's financial position. However, unforeseeable events will, by their very nature, be difficult to define. An unforeseeable event that materially impacts on a NSW DNSP's ability to provide direct control services should not be precluded from pass through solely on the basis that it is not possible to specifically define the event in advance of its occurrence. The AER therefore considers that nominated pass through events should be divided into two categories:

i. **specific nominated pass through events** – these are foreseeable events that can easily be defined. An event is only a specific nominated pass through event if the AER nominates the event in this distribution determination. The AER has

981 AER, *Draft decision*, pp. 279–280.
982 EnergyAustralia, *Revised regulatory proposal*, pp. 129–130.

considered the above eight criteria in deciding what events should be specific nominated pass through events.

ii. **a general nominated pass through event** – this will apply to unforeseeable events. This event is a set of broadly defined circumstances, the occurrence of which will constitute a general nominated pass through event. The AER will determine throughout the next regulatory control period whether an event constitutes a general nominated pass through event.

Specific nominated pass through events

A specific nominated event must be foreseeable in terms of its occurrence during the regulatory control period, despite the timing and/or cost impact being unforeseeable at the time the AER makes its distribution determination. In such circumstances, the AER considers it preferable that these costs be included when the costs of these activities are able to be forecast on a reasonable basis and when the timing of these events is known with certainty.

An event will be considered foreseeable if, at the time the AER makes its distribution determination, the event was expected to occur during the next regulatory control period. An example of such an event is the retail project event that the AER accepted as a nominated pass through event in its draft decision.[983] Public statements made by the NSW Government support the likelihood that this event will occur during the next regulatory control period.[984] An event such as a natural disaster or a general change in legal obligations, while a possibility, is not expected to occur during the next regulatory control period. Such an event is therefore not considered by the AER to be foreseeable.

General nominated pass through events

The AER recognises the possibility of events occurring during a regulatory control period that are uncontrollable, unforeseen, and have a material impact on costs. Examples of such an event include a major natural disaster such as a bushfire or earthquake, and liability for claims relating to asbestos or electric and magnetic fields. In these situations, although the occurrence of the event may be a possibility, its occurrence is unforeseen in that the event is not expected to occur during the next regulatory control period.

If an unforeseeable and uncontrollable event would have a material impact on a NSW DNSP's costs such that it would jeopardise the DNSP's ability to provide direct control services in accordance with the requirements of the NEL and the transitional chapter 6 rules, it is appropriate that the costs should be passed through to consumers. Where an event is of such an unusual and unexpected nature, and the associated costs are likely to have such an impact on the returns of the business that services would be jeopardised, it may be appropriate that the costs associated with the event should be passed through to customers immediately rather than waiting until the next regulatory control period.

Unforeseeable events are not easily defined. Therefore, rather than attempting to specifically define all unforeseeable events that could possibly occur during a regulatory control period, the AER considers it is appropriate to define a general set of circumstances, the occurrence of which will constitute a general pass through event.

983 AER, *Draft decision*, p. 286.

984 See, for example, NSW Premiers Office, *Strengthening the NSW Economy: energy reforms begin new phase*, 5 March 2009.

The AER considers that an event should be classified as a general pass through event in the following circumstances:

- an uncontrollable and unforeseeable event that falls outside of the normal operations of the business, such that prudent operational risk management could not have prevented or mitigated the effect of the event, occurs during the next regulatory control period
- the change in costs of providing distribution services as a result of the event is material, and is likely to significantly affect the DNSP's ability to achieve the operating expenditure objectives and/or the capital expenditure objectives (as defined in the transitional chapter 6 rules) during the next regulatory control period
- the event does not fall within any of the following definitions:
  - 'regulatory change event' in the NER (read as if paragraph (a) of the definition were not a part of the definition);
  - 'service standard event' in the NER;
  - 'tax change event' in the NER;
  - 'terrorism event' in the NER;
  - 'retail project event' in this final decision;
  - 'smart meter event' in this final decision (read as if paragraph (a) of the definition were not a part of the definition);
  - 'emissions trading scheme event' in this final decision (read as if paragraph (a) of the definition were not a part of the definition);
  - 'aviation hazards event' in this final decision.

An event will be considered unforeseeable for the purposes of this definition if, at the time the AER makes its distribution determination, despite the occurrence of the event being a possibility, there was no reason to consider that the event was more likely than not to occur during the next regulatory control period.

The AER will assess the DNSP's ability to achieve the operating expenditure objectives and/or the capital expenditure objectives in the same manner as it would assess the DNSP's ability to achieve those objectives under the NER as part of a distribution determination.

If a general pass through event occurs, a NSW DNSP may apply to the AER for a pass through of the costs associated with the event under clause 6.6.1 of the transitional chapter 6 rules.

In assessing an application for a pass through event (whether the event is a specific nominated event, a general nominated event, or an event defined in the transitional chapter 6 rules), the AER will take into account the matters listed in clause 6.6.1(j) of the transitional chapter 6 rules. These matters include the need to ensure the NSW DNSP recovers only incremental costs, and the efficiency of the NSW DNSP's decisions and actions in relation to the risk of the event, including whether the NSW DNSP has failed to take reasonable action to reduce the magnitude of the event. The AER will also consider the materiality of the costs proposed for pass through.

Materiality

The transitional chapter 6 rules require that a positive change event must have a material impact on costs before it can be passed through to consumers. The AER released a preliminary position on its approach to materiality in December 2007, which stated that an event is material if:[985]

- the revenue impact in any one year exceeds 1 per cent of the respective DNSP's revenue for the first year of the regulatory control period; or
- the proposed capital expenditure exceeds 5 per cent of the aggregate annual revenue requirement in the first year of the regulatory control period.

Country Energy considered that the distribution determination should define a materiality threshold. It suggested that the threshold applied in transmission would be a reasonable starting point, but the AER should consider a lower threshold for events triggered by asymmetric risk. Integral Energy referred to the AER's preliminary position on materiality, and suggested that a zero threshold should apply to an automated interval meter event. EnergyAustralia proposed specific meanings of 'material' in the definitions of each of its proposed pass through events except for the dead zone event.[986]

The AER considers that a materiality threshold should apply to all nominated pass through events. The AER agrees that different thresholds for materiality should be applied for different types of pass through events.

In the absence of a significant materiality threshold, DNSPs may seek to pass through costs of a non-material nature that could be accommodated by the DNSP in the normal course of its operational activities and budget management. To do otherwise could potentially undermine the DNSPs' incentives to manage expenditure efficiently. Therefore, the AER considers that a significant materiality threshold should generally apply to pass through events.

The AER agrees with Country Energy that the threshold of 1 per cent applied to transmission pass through events is a reasonable threshold. This is also the same threshold that the AER proposed to adopt in its preliminary position paper on its approach to materiality in December 2007.

The AER will generally consider that a pass through event will have a material impact if the costs associated with the event would exceed 1 per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

985 AER, *Preliminary positions, Matters relevant to distribution determinations for ACT and NSW DNSP 2009–2014: Demand management incentive scheme, Control mechanisms for alternative control services, Approach to determining materiality for possible pass through events,* December 2007, p. 50.

986 EnergyAustralia, *Revised regulatory proposal*, attachment 15.1.

Given the potentially broad nature of a general nominated pass through event, and that it will only apply where the event would have a significant impact on the financial returns of the DNSP, this materiality threshold must be satisfied. The AER considers that this materiality threshold must be satisfied in order for the costs associated with a pass through event to warrant immediate pass through to customers under a general nominated pass through event, rather than waiting for costs to be re-assessed at the following regulatory control period.

In some circumstances, however, the AER may determine that a lower materiality threshold is appropriate. Costs associated with a specific nominated event were not included in the forecast costs at the time of the regulatory determination because, at the time the regulatory proposals were submitted, the precise timing of the event and/or the cost impact of the event could not be forecast on a reasonable basis. In these circumstances, it is appropriate that a lower materiality threshold be adopted that represents the administrative costs of assessing such an application. The costs associated with these events would have been included, without regard to the materiality of the financial impact of the event on the DNSP, had the necessary information been available at the time of the final decision. The costs of assessing a cost pass through may, in certain circumstances, be very low. As specific nominated pass through events are narrowly defined, the AER considers that a low materiality threshold will not undermine incentives to manage expenditure efficiently.

The AER does not agree with Country Energy that a lower materiality threshold should apply to events triggered by asymmetric risks. A lower materiality threshold in these circumstances may undermine incentives to manage expenditure allowances efficiently. Furthermore, the AER considers that the risks of forecasts being underestimated and overestimated should be treated equally in terms of materiality.

15.5.2 Issues raised in submissions

15.5.2.1 General issues

Regulatory change events

In the draft decision, the AER rejected some nominated cost pass through events on the basis that the events were likely to constitute regulatory change events, and accordingly those events were already defined in the rules.[987] However, the AER now accepts that some of these events may not satisfy the definition of a regulatory change event. In particular, some of the proposed events were specifically defined by NSW DNSPs to exclude events falling into any other category of pass through event.[988] Therefore, these events are not regulatory change events, and satisfy the criterion of the event not being captured by defined event conditions.

Incentive framework

The NSW DNSPs argued that accepting events as pass through events will not undermine a DNSP’s incentives to argue against the introduction of the events. This issue was raised in response to the AER referring to Wilson Cook’s concerns that accepting smart meters as a pass through event may undermine incentives to argue against the introduction of

987 AER, *Draft decision*, p. 281.

988 Integral Energy, *Revised regulatory proposal*, p. 74 and EnergyAustralia, *Revised regulatory proposal*, Attachment 15A.

smart meters if the DNSP considered the costs to be inefficient, and the AER's suggestion that these concerns are relevant to other pass through events.

EnergyAustralia argued that in making investment decisions, there are many factors taken into account that are predominantly driven by factors other than cost impacts on DNSPs. It was further suggested that it is unreasonable to conclude that DNSPs could influence decisions to introduce an emissions trading scheme.[989]

The AER has considered these submissions, and accepts that the nomination of an event as a pass through event, per se, will not always undermine DNSPs' incentives to argue against that event. The AER accepts that factors other than cost impacts may be considered by DNSPs in deciding whether to argue against the introduction of proposed events such as smart meters. Where a DNSP is unlikely to affect a government decision to introduce a scheme such as an emissions trading scheme, accepting the event as a pass through event is unlikely to affect a DNSP's incentives to argue against the introduction of the scheme.

Alternative control services

The AER considers that it is appropriate to apply the pass through provisions of the transitional chapter 6 rules to alternative control services, as all direct control services are subject to the distribution determination. Therefore, the events that are nominated in this decision will apply to all direct control services.

15.5.2.2 Issues relating to specific events

The AER's consideration of issues relating to specific events is detailed in sections 15.5.3 and 15.5.4 of this decision.

15.5.3 Nominated pass through events that the AER accepts

Retail project event

The AER does not agree with the EUAA that the costs associated with the separation of retail and distribution businesses should be funded out of the sale proceeds received by the NSW Government from the privatisation and not by end users. It may be difficult for the NSW Government to estimate these costs and include them in the sale price.

EnergyAustralia suggested that the effect of the AER's definition in the draft determination of this event is that DNSPs could only potentially recover increased costs incurred in providing direct control services in the 2014–19 regulatory control period. EnergyAustralia proposed a definition which covered events occurring during 'the regulatory control period'.[990]

The AER definition of a retail project event in the draft decision referred to an event:

> …which materially changes the costs to the DNSP of providing direct control services in the next regulatory control period.[991]

The draft decision defined 'next regulatory control period' on page ix as the regulatory control period from 1 July 2009 to 30 June 2014. Therefore the definition in the draft

[989] EnergyAustralia, *Revised regulatory proposal*, p. 133.
[990] EnergyAustralia, *Revised regulatory proposal*, attachment 15.1, p. 3.
[991] AER, *Draft decision*, p. 286.

decision refers to changes in costs in the 1 July 2009 to 30 June 2014 regulatory control period only. EnergyAustralia's suggestion that the definition restricts cost recovery to the 2014–19 regulatory control period is not correct, and the definition does not require amendment.

The AER considers that the retail project event meets the criteria listed in section 15.5.1 of this final decision for a specific nominated pass through event. The event is foreseeable in that it is expected to occur during the next regulatory control period, however, the timing and cost impact is uncertain. It is also an uncontrollable, uninsurable event.

The AER position in the draft decision remains unchanged and the AER accepts a retail project event as a specific nominated pass through event, defined as:

> Any legislative or administrative act of the NSW Government to separate the retail electricity business of a DNSP in whole or in part from the electricity distribution function of the DNSP (including by way of a sale of the DNSPs retail business), which materially changes the costs to the DNSP of providing direct control services in the next regulatory control period.

This means that if the NSW Government decides to separate the retail electricity businesses from the distribution functions of the NSW DNSPs, and as a consequence the costs to the NSW DNSPs of providing direct control services changes materially, the NSW DNSPs may apply for a pass through.

Aviation hazards event

Country Energy proposed an event to capture changes in risk assessment costs due to court cases and other legal obligations. In support of this proposed event, Country Energy provided information relating to the findings in the recent case of *Sheather v Country Energy*[992] (the Sheather decision) as well as Coronial Inquests[993] involving similar circumstances that have resulted in increased obligations for Country Energy relating to the mitigation of risks of aviation hazards. Country Energy indicated in its regulatory proposal that it has two options following the Sheather decision:[994]

- approach the government for legislative protection from liability for powerlines, where those powerlines otherwise comply with Australian and safety standards, or
- modify its risk assessment practices and implement further controls to mitigate these risks.

In response to the AER draft decision to reject the proposed pass through event, Country Energy included in its revised regulatory proposal, a forecast of the costs it is likely to incur as a result of the Sheather decision in its proposed opex allowance.[995] As noted in section 8.5.1.4 of this final decision, the AER does not consider that the costs associated with the Sheather decision should be included in Country Energy's opex allowance.

Ordinarily, the costs of these obligations would be included in a DNSP's building block forecasts. However, due to the timing of the findings of the Coronial Inquiry being

992 Sheather v Country Energy [2007] NSWCA 179 (24 July 2007).

993 Inquests into the Deaths of Ross Kenneth Mill, Benjamin McDonnell, Shane Haldane Thrupp, Ian Phillip Stephenson and Malcolm John Buerckner, Magistrate Milovanovich Deputy State Coroner, Mudgee Court 30.4.07 to 4.5.07 and Forbes Court 21.7.08 to 1.8.08.

994 Country Energy, *Regulatory proposal*, pp. 169–170.

995 Country Energy, *Revised regulatory proposal*, pp. 28–29.

released, it is not possible for Country Energy to develop reliable forecasts until some time after the commencement of the 2009–14 regulatory control period. This is because a strategy and feasibility study is necessary before robust and reasonable forecasts can be developed. Accordingly, the AER's consultant, Energy and Management Services, suggested that the AER may wish to reconsider whether this event should be a pass through event. Country Energy indicated in its revised regulatory proposal that it will incur increased costs as a result of compliance obligations arising from the Sheather decision from 2010–11.[996] This increase in costs is a foreseeable event that it is expected to occur during the regulatory control period. However, reasonable forecasts of the costs of this event cannot be developed at this time. The event is also uncontrollable, in that the increased obligations are externally imposed and it is not insurable. The event is not likely to constitute a regulatory change event, as the obligations are not imposed by statute.

Taking into account the criteria listed in section 15.5.1 of this final decision, the AER considers that the obligations arising from the Sheather decision should be nominated as a specific nominated pass through event. The reasons for this conclusion are:

- the event is not already captured by the defined event definitions
- the event is uncontrollable
- although the event is foreseeable, the timing and cost impact can not be reasonably forecast at this time
- the event is not insurable.

The AER therefore decides to nominate an aviation hazards event as a specific nominated pass through event for Country Energy, defined as:

> **Aviation hazards event:** this event occurs if:
>
> 1. Country Energy requests legislative protection from the government for potential liabilities (related to the findings in Sheather v Country Energy and the coronial inquests in the Mudgee Court 30.4.07 to 4.5.07 and Forbes Court 21.7.08 to 1.8.08) arising from powerlines, where those powerlines otherwise comply with Australian and industry standards, and
>
> 2. The relevant government authority advises that Country Energy will not be provided with legislative protection from liability for these events, and
>
> 3. A strategy and feasibility study is completed by or for Country Energy, in consultation with CASA and the relevant regulatory authorities, that identifies actions necessary to mitigate the risks of aviation hazards.

Smart meter/automated interval meter event

In the draft decision the AER rejected the smart meter/automated interval meter nominated pass through event because the AER considered the event would constitute a regulatory change event and the passing through of the costs associated with the event would undermine the incentive arrangements within the regulatory regime.[997]

[996] Country Energy, *Revised regulatory proposal*, pp. 28–29.
[997] AER, *Draft decision*, p. 269.

The AER notes that Integral Energy defined a smart meter event to exclude circumstances in which the event would be a regulatory change event. Therefore the event is not captured by defined events.

EnergyAustralia and Integral Energy rejected the argument that allowing it as a pass through event would undermine their incentives to argue against the introduction of the event. The AER has considered these submissions and agrees that allowing the event as a pass through event would not undermine a DNSP's incentives to argue against the introduction of the event.

In December 2008, the MCE released an exposure draft of amendments to the NEL to facilitate and support the accelerated roll out and trials of smart meters in participating jurisdictions.[998] It is therefore reasonable to suggest that a smart meter is expected to occur during the next regulatory control period, and accordingly the event satisfies the foreseeability requirement.

Taking into account the criteria listed in section 15.5.1 of this decision, the AER considers that the smart meter event should be nominated as a specific nominated pass through event. The reasons for this conclusion are:

- the event is not already captured by the defined event definitions
- the event is uncontrollable because if the event occurs, a NSW DNSP will be legally obliged to undertake trials and/or roll outs
- the event is foreseeable, although the timing and cost impact can not be reasonably forecast, as the timing and scope of the obligation is not known at this time
- the event is not insurable
- passing through the costs will not undermine regulatory incentives, given that the obligation will be imposed externally.

The AER therefore decides to nominate a smart meter event as a specific nominated pass through event, defined as:

> **A smart meter event** is an event which results in an obligation being externally imposed on a DNSP to install smart meters for some or all of its customers, or to conduct large scale metering trials during the course of the next regulatory control period, regardless of whether that requirement takes the form of the imposition of a statutory obligation or not, and which:
>
> (a) falls within no other category of pass through event; and
>
> (b) increases the costs of a DNSP providing direct control services.

The AER does not agree with Integral Energy that a smart meter event should be given a zero materiality threshold. If the costs of the event were sufficiently small that the reasonable costs of assessing an application for pass through exceeded the costs of the event, it would not be efficient to pass through those costs. A smart meter event will therefore be considered material if the costs of the event exceed the reasonable costs incurred in assessing the pass through application.

[998] MCE, Standing Committee of Officials, *Bulletin No. 140*, 23 December 2008. Available: www.mce.gov.au

Emissions trading scheme event

In the draft decision the AER rejected this nominated pass through event because the it considered the event would constitute a regulatory change event.[999]

The AER notes that Integral Energy defined an emissions trading scheme event to exclude circumstances in which the event would be a regulatory change event. Therefore the event is not captured by defined events.

EnergyAustralia and Integral Energy rejected the argument that allowing an emissions trading scheme event as a pass through event would undermine their incentives to seek a lower cost arrangement.[1000] The AER has considered these submissions and agrees that allowing the event as a pass through event would not undermine a NSW DNSP's incentives to argue against the introduction of the event, as noted in section 15.5.2.1 of this final decision.

The Commonwealth Department of Climate Change has indicated that a carbon emissions trading scheme will commence by 2010.[1001] This event is foreseeable in that it is expected to occur during the next regulatory control period. As the scope of the scheme is yet to be finalised, NSW DNSPs cannot reasonably forecast the costs of the scheme they will incur during the next regulatory control period.

This event is not insurable and given that it will be externally imposed and DNSPs cannot mitigate its effects by altering internal management practices, passing through the costs will not undermine the incentive arrangements within the regulatory regime.

Taking into account the factors listed in section 15.5.1 of this decision, the AER considers that the emissions trading scheme event should be nominated as a specific nominated pass through event. The reasons for this conclusion are:

- the event is not already captured by the defined event definitions
- the event is uncontrollable because if the event occurs, a NSW DNSP will be legally obliged to comply with the scheme
- although the event is foreseeable, the timing and cost impact can not be reasonably forecast, as the scope of the obligation is not known at this time
- the event is not insurable
- passing through the costs will not undermine regulatory incentives, given that the obligation will be imposed externally.

The AER therefore decides to nominate an emissions trading scheme event as a specific nominated pass through event, defined as:

> **An emissions trading scheme event** is an event which results in the imposition of legal obligations on a DNSP arising from the introduction or operation of a carbon emissions trading scheme imposed by the Commonwealth or NSW Government during the course of the next regulatory control period and which:

[999] AER, *Draft decision*, p. 281.

[1000] EnergyAustralia, *Revised regulatory proposal*, pp. 132–134; and Integral Energy, *Revised regulatory proposal*, pp. 74–75.

[1001] Department of Climate Change, *Carbon pollution reduction scheme: timetable*, 10 March 2009.

(a) falls within no other category of pass through event; and

(b) materially increases the costs of providing direct control services.

15.5.4 Nominated pass through events that the AER does not accept

Force majeure event

The AER accepted this event in the draft decision. It was defined as:[1002]

> Any major fire, flood, earthquake, storm or other weather-related or natural disaster, act of God, riot, civil disorder, rebellion or other similar cause beyond the control of the DNSP (but excluding any insurable events – that is, those events for which external insurance or self insurance is feasible) that occurs during the next regulatory control period and materially changes the costs to the DNSP of providing direct control services.

The AER considers that there is a risk in attempting to capture all natural disaster–type events in a single definition. ActewAGL proposed a definition that is similar in meaning, with some technical differences to the force majeure event in NSW.[1003] It would be undesirable for a similar event occurring in two jurisdictions to be recoverable under the pass through provisions in one jurisdiction, and not recoverable in another jurisdiction based simply on the drafting of the event definition. Rather than attempting to capture all appropriate events in this definition, the AER considers that a NSW DNSP should apply for a general nominated pass through event if such an event occurs.

The AER's revised approach of considering foreseeability as a threshold question leads to a different conclusion to that proposed in the draft decision. The AER acknowledges that the occurrence of a force majeure event during the regulatory control period is a possibility, however, there is no reason to suggest that it is expected to occur. This event is therefore not foreseeable.

Taking into account the factors listed in section 15.5.1 of this final decision, the AER considers that the force majeure event should not be nominated as a specific nominated pass through event. The reason for this conclusion is that the occurrence of such an event during the next regulatory control period is not foreseeable. However, if the event occurs during the next regulatory control period and materially impacts a NSW DNSP's costs, the event may constitute a general nominated pass through event. The AER would assess an application for cost pass through having regard to this final decision and the requirements of the NER.

Earthquakes above magnitude five

Country Energy sought to include earthquakes above magnitude five as insurable events in its opex forecasts or, in the alternative, included as a nominated pass through event.[1004] As discussed in chapter 8 of this final decision, the AER considers that it is not feasible for Country Energy to calculate a self insurance premium in regards to earthquakes above magnitude five. It is more appropriate that earthquakes above magnitude five are considered under the pass through provisions of the transitional chapter 6 rules.

[1002] AER, *Draft decision*, pp. 286–287.
[1003] ActewAGL, *Regulatory proposal*, p. 270.
[1004] Country Energy, *Revised regulatory proposal*, pp. 30, 65.

The AER acknowledges that the occurrence of an earthquake above magnitude five event during the next regulatory control period is a possibility, however, there is no reason to suggest that it is expected to occur. The AER considers that it is therefore not appropriate to define a specific nominated event to cover these circumstances. However, Country Energy may apply to the AER for a general nominated pass through if an earthquake above magnitude five occurs during the next regulatory control period.

Taking into account the factors listed in section 15.5.1 of this final decision, the AER considers that earthquakes above magnitude five events should not be included as a specific nominated pass through event. The reason for this conclusion is that the occurrence of such an event during the next regulatory control period is not foreseeable. However, if the event occurs during the next regulatory control period and materially impacts a NSW DNSP's costs, the event may constitute a general nominated pass through event. The AER would assess an application for cost pass through having regard to this final decision and the requirements of the NER.

Compliance event/functional change event/changes in reporting requirements

These proposed events seek to allow a pass through of costs incurred due to changes in existing obligations (including compliance obligations and reporting requirements), changes in interpretation of obligations and the creation of new obligations.

In the draft decision the AER rejected the inclusion of these events as nominated pass through events. The AER considered that management discretion exists in regards to these events such that there is some control over its expenditure.[1005] DNSPs responded by stating that they do not have discretion as to whether or not they comply with legal obligations, and therefore these events are outside their control.[1006] The AER accepts that DNSPs do not have a choice in regards to compliance with the law.

A specific nominated event must be foreseeable in terms of its occurrence during the regulatory control period, despite the timing and/or cost impact being unforeseeable at the time of submitting forecasts. These events do not relate to any specific pending change in obligations[1007] and while it is possible that these events may occur during the next regulatory control period, they are not expected to occur. Therefore these events are not foreseeable.

Taking into account the factors listed in section 15.5.1 of this final decision, the AER considers that the compliance event/functional change event/changes in risk assessment costs due to court cases and other legal obligations should not be nominated as a specific nominated pass through event. The reason for this conclusion is that the occurrence of such an event during the next regulatory control period is not foreseeable. However, if the event occurs during the next regulatory control period and materially impacts on a NSW DNSP's costs, the event may constitute a general nominated pass through event. The AER would assess an application for cost pass through having regard to this final decision and the requirements of the NER.

1005 AER, *Draft decision*, pp. 281–282.
1006 EnergyAustralia, *Revised regulatory proposal*, p. 135.
1007 However, the Sheather decision does relate to specific obligations. This is discussed at section 15.5.3 of this final decision.

Distribution loss event

This event relates to the imposition of costs or legal obligations relating to distribution losses from the operation of Integral Energy's distribution network. The AER acknowledges that this event may not constitute a regulatory change event, and is therefore not already captured by the defined events.

A specific nominated event must be foreseeable in terms of its occurrence during the next regulatory control period, despite the timing and/or cost impact being unforeseeable at the time of submitting forecasts. While it is possible that a distribution loss event may occur during the next regulatory control period, it is not expected to occur and therefore does not satisfy the foreseeability requirement.

Taking into account the factors listed in section 15.5.1 of this final decision, the AER considers that a distribution loss event should not be nominated as a specific nominated pass through event. The reason for this conclusion is that the occurrence of such an event during the next regulatory control period is not foreseeable. However, if the event occurs during the next regulatory control period and materially impacts on a NSW DNSP's costs, the event may constitute a general nominated pass through event. The AER would assess an application for cost pass through having regard to this final decision and the requirements of the NER.

Electric and magnetic fields event

In the draft decision the AER rejected this pass through event because insurance is available for third party claims.[1008] In response to the draft decision, Country Energy and Integral Energy removed third party claims from the definition of an electric and magnetic fields event in their revised regulatory proposals.

The AER accepts that this pass through event may not satisfy the definition of a regulatory change event in chapter 10 of the NER, and that the amended definitions mean that the event is not insurable.

A specific nominated event must be foreseeable in terms of its occurrence during the regulatory control period, despite the timing and/or cost impact being unforeseeable. While it is possible that an electric and magnetic fields event may occur during the next regulatory control period, it is not expected to occur and therefore does not satisfy the foreseeability requirement.

Taking into account the factors listed in section 15.5.1 of this final decision, the AER considers that the electric and magnetic fields event should not be nominated as a specific nominated pass through event. The reason for this conclusion is that the occurrence of such an event during the next regulatory control period is not foreseeable. However, if the event occurs during the next regulatory control period and materially impacts on a NSW DNSP's costs, the event may constitute a general nominated pass through event. The AER would assess an application for cost pass through having regard to this final decision and the requirements of the NER.

[1008] AER, *Draft decision*, p. 284.

Customer connection event

EnergyAustralia indicated in supplementary submissions to the AER that since submitting its capex forecasts to the AER, it now seems likely that several major customer projects that were not included in the capex forecasts are likely to proceed in the next regulatory control period. Although EnergyAustralia offered in its submission to provide further details to the AER on a confidential basis, further details were not provided.

The AER does not have sufficient information to decide whether or not this event is foreseeable. The AER maintains its view that it is more appropriate for NSW DNSPs to bear the risks of deviations from forecast capital projects than it is for consumers to bear those risks. EnergyAustralia's total capex allowance is approved for the whole of the regulatory control period. EnergyAustralia is free to spend its capex allowance in the manner it sees fit. If an unplanned project eventuates, EnergyAustralia is free to spend more of its allowance on that project than was contemplated at the time of its regulatory proposal. Similarly, EnergyAustralia may spend less of its allowance on a planned project if the costs associated with that project turn out to be less than the forecast provided at the time of the regulatory proposal. This flexibility allows EnergyAustralia to revise its expenditure priorities as circumstances change throughout the regulatory control period. It is therefore appropriate that EnergyAustralia should bear this risk.

The AER also considers that passing through the costs of the event would undermine EnergyAustralia's incentives to undertake prudent and efficient planning activities. If EnergyAustralia was permitted to pass through the costs of any project not factored into its forecasts, the incentive to provide robust forecasts would be diminished.

Taking into account the factors listed in section 15.5.1 of this final decision, the AER considers that the customer connection event should not be nominated as a specific nominated pass through event. The reasons for this conclusion are:

- EnergyAustralia is in the best position to bear the risk of the event.
- Passing through the costs of the event would undermine incentives of the regulatory regime.

The AER considers it is unlikely that a customer connection event would constitute a general nominated pass through event. This is because the definition of a general nominated pass through event requires that the event occurs outside of the normal operations of the business, and it appears that a customer connection event is within the normal operations of the business.

Insurance event

Country Energy suggested there is potential for substantial changes to the value of insurance premiums or that insurance becomes unavailable over the next regulatory control period.[1009] Integral Energy also proposed an insurance event and sought an insurance event.[1010]

A specific nominated event must be foreseeable in terms of its occurrence during the next regulatory control period, despite the timing and/or cost impact being unforeseeable.

1009 Country Energy, *Revised regulatory proposal*, pp. 65–66.
1010 Integral Energy, *Revised regulatory proposal*, p. 80.

While it is possible that an insurance event may occur during the next regulatory control period, there is no information to suggest that it is expected to occur, and therefore the event does not satisfy the foreseeability requirement.

Taking into account the factors listed in section 15.5.1 of this final decision, the AER considers that an insurance event should not be nominated as a specific nominated pass through event. The reason for this conclusion is that the occurrence of such an event during the next regulatory control period is not foreseeable. However, if the event occurs during the next regulatory control period and materially impacts on a NSW DNSP's costs, the event may constitute a general nominated pass through event. The AER would assess an application for cost pass through having regard to this final decision and the requirements of the NER.

Cost or demand variance event

EnergyAustralia proposed a cost or demand variance event to cover unexpected or unforeseeable changes in demand or cost movements that trigger new investments or materially alter the costs of current or planned investments.[1011] The draft decision rejected this proposal on the grounds that it would undermine the incentive arrangements within the regulatory regime.[1012] EnergyAustralia noted that the event would only occur where there was a material impact on costs, and would not occur in circumstances involving variations to normal business costs and demand.

A specific nominated event must be foreseeable in terms of its occurrence during the next regulatory control period, despite the timing and/or cost impact being unforeseeable. While it is possible that a cost or demand variance event may occur during the next regulatory control period, it is not expected to occur and therefore does not satisfy the foreseeability requirement.

The AER considers that a NSW DNSP is better placed to manage the risk of a cost or demand variance event. Given that NSW DNSPs have discretion to manage their total expenditure allowances, if this event occurred, the DNSP could reprioritise its expenditure to address the change in circumstances. The AER acknowledges that the event is defined to include only material impacts on costs. However, the AER maintains that allowing this event as a specific nominated pass through event would undermine regulatory incentives, as it reduces the incentive to provide robust forecasts and cost escalators.

Taking into account the factors listed in section 15.5.1 of this final decision, the AER considers that a cost and demand variance event should not be nominated as a specific nominated pass through event. The reasons for this conclusion are:

- the event is not foreseeable
- the NSW DNSP is in the best position to manage the risk
- passing through the costs would undermine the incentives of the regulatory regime.

The AER considers it is unlikely that a cost or demand variance event would constitute a general nominated pass through event. This is because the definition of a general

1011 EnergyAustralia, *Revised regulatory proposal*, pp. 143–144.
1012 AER, *Draft decision*, p. 285.

nominated pass through event requires that the event occurs outside of the normal operations of the business, and it appears that a cost or demand variance event is within the normal operations of the business. Furthermore, prudent operational risk management is likely to prevent or mitigate the impact of such an event.

Dead zone event

In the draft decision the AER considered that the transitional chapter 6 rules made no allowance for a dead zone event in the pass through provisions. The AER indicated that costs incurred for an event which occurs between a NSW DNSP's submission of its regulatory proposal and the commencement of the next regulatory control period can be passed through in an application made in the next regulatory control period provided the application is made within 90 days of the pass through event occurring.[1013]

EnergyAustralia considered that the AER had misinterpreted the transitional chapter 6 rules. Furthermore it suggested that it was not possible to delay submission because the transitional chapter 6 rules do not provide any mechanism for doing so. It considered that if an event occurs during the current regulatory control period but its cost impact is in the next regulatory control period it will not be caught by any of the pass through event definitions contained in chapter 10 of the NER.[1014]

The AER has further considered the application of the pass through provisions of the chapter 6 transitional rules in the context of EnergyAustralia's proposed dead zone event.

The AER agrees with EnergyAustralia's statement that:[1015]

> …the 'relevant regulatory control period' for the purposes of the above definitions [of regulatory change event, service standard event, and tax change event] is the regulatory control period in which the relevant event occurs. The effect of this is that if an event (that would otherwise be a *regulatory change event, service standard event*, or a *tax change event*) occurs during the current regulatory period, but its cost impact is in the next regulatory period, it will not be caught by any of these pass through event definitions.

The above statement refers to defined events. The AER also considers that if a nominated event occurs during a regulatory control period but its cost impact is in the subsequent regulatory control period, the transitional chapter 6 rules do not permit the costs of the event to be passed through to customers.

In relation to a positive pass through event, the 'eligible pass through amount' is 'the increase in costs in the provision of direct control services that the DNSP has incurred or is likely to incur until the end of the regulatory control period as a result of that positive change event'.[1016] The words 'regulatory control period' appear to refer to the regulatory control period in which the relevant positive change event occurs. Therefore, the 'eligible pass through amount' that the DNSP may pass through and the relevant positive pass through event should relate to the same regulatory control period. The same reasoning also applies to a negative pass through event.

[1013] AER, *Draft decision*, p. 2820.
[1014] EnergyAustralia, *Revised regulatory proposal*, pp. 137–139.
[1015] EnergyAustralia, *Revised regulatory proposal*, p. 138.
[1016] Definition of 'eligible pass through amount' is outlined in chapter 10 of the NER.

Given that the costs associated with a pass through event must be passed through in the regulatory control period in which the event occurs, the AER no longer considers that the costs associated with a pass through event that occurs in a regulatory control period can be passed through in an application made in the next regulatory control period, even if the application is made within 90 days of the pass through event occurring.

As EnergyAustralia's proposed event involves passing through the costs of an event in a subsequent regulatory control period to that in which the event actually occurred, the AER considers that the chapter 6 transitional rules do not permit this as a pass through event.

The AER considers that the proposed dead zone event should not be nominated as a pass through event because the transitional chapter 6 rules do not permit the passing through of the costs of the event.

Retailer of last resort

The AER acknowledges that this event may not constitute a regulatory change event.

A specific nominated event must be foreseeable in terms of its occurrence during the regulatory control period, despite the timing and/or cost impact being unforeseeable. While it is possible that a retailer of last resort event may occur during the next regulatory control period, there is no information to suggest that it is expected to occur, and therefore this event does not satisfy the foreseeability requirement.

Taking into account the factors listed in section 15.5.1 of this final decision, the AER considers that a retailer of last resort event should not be nominated as a specific nominated pass through event. The reason for this conclusion is that the occurrence of such an event during the next regulatory control period is not foreseeable. However, if the event occurs during the next regulatory control period and materially impacts on a NSW DNSP's costs, the event may constitute a general nominated pass through event. The AER would assess an application for cost pass through having regard to this final decision and the requirements of the NER.

Joint planning event

This event is general in nature, in that it relates to changes to capital projects rather than relating to any specific particular project.

A specific nominated event must be foreseeable in terms of its occurrence during the regulatory control period, despite the timing and/or cost impact being unforeseeable. While it is possible that a joint planning event may occur during the next regulatory control period, it is not expected to occur and therefore does not satisfy the foreseeability requirement.

The AER maintains its view that it is more appropriate for NSW DNSPs to bear the risks of deviations from forecast capital projects than it is for consumers to bear those risks. EnergyAustralia's total capex allowance is approved for the whole of the regulatory control period. EnergyAustralia is free to spend its capex allowance in the manner it sees fit. If an unplanned project eventuates or a planned project changes in scope, EnergyAustralia is free to spend more of its allowance on that project than was contemplated at the time of its regulatory proposal. Similarly, EnergyAustralia may spend less of its allowance on a planned project if the costs associated with that project turn out to be less than the forecast provided at the time of the regulatory proposal. This flexibility allows EnergyAustralia to revise its expenditure priorities as circumstances change throughout the regulatory control period. It is therefore appropriate that EnergyAustralia should bear this risk.

The AER also considers that passing through the costs of the event would undermine EnergyAustralia's incentives to undertake prudent and efficient planning activities. If EnergyAustralia was permitted to pass through the costs of certain projects not factored into its forecasts, or changes in the costs of forecast projects, the incentive to provide robust forecasts would be diminished.

Taking into account the factors listed in section 15.5.1 of this final decision, the AER considers that the customer connection event should not be nominated as a specific nominated pass through event. The reasons for this conclusion are:

- the event is not foreseeable
- nergyAustralia is in the best position to bear the risk of the event
- passing through the costs of the event would undermine incentives of the regulatory regime.

However, if the event occurs during the next regulatory control period and materially impacts on a NSW DNSP's costs, the event may constitute a general nominated pass through. The AER would assess an application for cost pass through having regard to this final decision and the requirements of the NER.

15.5.5 Events for which self insurance allowances were rejected

As discussed in chapter 8 of this final decision, the AER rejected some proposed allowances for self insurance on the basis that it was not feasible to calculate a self insurance premium, and concluded that those events should be dealt with under the pass through provisions of the transitional chapter 6 rules.

None of those events are foreseeable in that there is no information to suggest that the events are expected to occur during the next regulatory control period. Therefore, the AER considers that those events should not be nominated as specific nominated pass through events. However, if any of those events occur during the next regulatory control period and materially impact on a NSW DNSP's costs, the event may constitute a general nominated pass through event. The AER would assess an application for cost pass through having regard to this final decision and the requirements of the NER.

15.6 AER conclusion

15.6.1 Specific nominated pass through events

The AER accepts the following pass through events as nominated pass through events for Country Energy, EnergyAustralia and Integral Energy:

> **Retail project event:** any legislative or administrative act of the NSW Government to separate the retail electricity business of a DNSP in whole or in part from the electricity distribution function of the DNSP (including by way of a

sale of the DNSPs retail business), which materially changes the costs to the DNSP of providing direct control services in the next regulatory control period.

Smart meter event: an event which results in an obligation being externally imposed on a DNSP to install smart meters for some or all of its customers, or to conduct large scale metering trials during the course of the next regulatory control period, regardless of whether that requirement takes the form of the imposition of a statutory obligation or not, and which:

(a) falls within no other category of pass through event; and

(b) increases the costs of a DNSP providing direct control services.

Emissions trading scheme event: an event which results in the imposition of legal obligations on a DNSP arising from the introduction or operation of a carbon emissions trading scheme imposed by the Commonwealth or NSW Government during the course of the next regulatory control period and which:

(a) falls within no other category of pass through event; and

(b) materially increases the costs of providing direct control services.

The AER also accepts the following event as a specific nominated pass through event for Country Energy:

Aviation hazards event: this event occurs if:

1. Country Energy requests legislative protection from the government for potential liabilities (related to the findings in Sheather v Country Energy and the coronial inquests in the Mudgee Court 30.4.07 to 4.5.07 and Forbes Court 21.7.08 to 1.8.08) arising from powerlines, where those powerlines otherwise comply with Australian and industry standards, and

2. The relevant government authority advises that Country Energy will not be provided with legislative protection from liability for these events, and

3. A strategy and feasibility study is completed by or for Country Energy, in consultation with CASA and the relevant regulatory authorities, that identifies actions necessary to mitigate the risks of aviation hazards.

15.6.2 General nominated pass through event

The AER nominates the following general nominated pass through event for Country Energy, EnergyAustralia and Integral Energy.

A general nominated pass through event occurs in the following circumstances:

1. An uncontrollable and unforeseeable event that falls outside of the normal operations of the business, such that prudent operational risk management could not have prevented or mitigated the effect of the event, occurs during the next regulatory control period

2. The change in costs of providing distribution services as a result of the event is material, and is likely to significantly affect the DNSP's ability to achieve the operating expenditure objectives and/or the capital expenditure objectives (as defined in the transitional chapter 6 rules) during the next regulatory control period

3. The event does not fall within any of the following definitions:

'regulatory change event' in the NER (read as if paragraph (a) of the definition were not a part of the definition);

'service standard event' in the NER;

'tax change event' in the NER;

'terrorism event' in the NER;

'retail project event' in this final decision;

'smart meter event' in this final decision (read as if paragraph (a) of the definition were not a part of the definition);

'emissions trading scheme event' in this final decision (read as if paragraph (a) of the definition were not a part of the definition);

'aviation hazards event' in this final decision.

For the purposes of this definition:

- an event will be considered unforeseeable if, at the time the AER makes its distribution determination, despite the occurrence of the event being a possibility, there was no reason to consider that the event was more likely to occur than not to occur during the next regulatory control period

- 'material' means the costs associated with the event would exceed 1 per cent of the smoothed forecast revenue specified in the final decision in the years of the regulatory control period that the costs are incurred.

For the reasons set out in this chapter, the AER considers that the other events proposed by the NSW DNSPs should be nominated as specific nominated pass through events. However, even if an event is not a nominated specific pass through event, if the event occurs, the AER notes that a NSW DNSP may apply to the AER during the next regulatory control period for a pass through where a general nominated pass through event occurs. The AER will determine throughout the next regulatory control period whether an event constitutes a general nominated pass through event.

In assessing a NSW DNSP's application for a pass through event (whether the event is a specific nominated event, a general nominated event, or an event defined in the transitional chapter 6 rules), the AER will take into account the matters listed in clause 6.6.1(j) of the transitional chapter 6 rules. These matters include the need to ensure the NSW DNSP recovers only incremental costs, and the efficiency of the NSW DNSP's decisions and actions in relation to the risk of the event, including whether the NSW DNSP has failed to take reasonable action to reduce the magnitude of the event.

15.7 AER decision

In accordance with clause 6.12.1(14) of the transitional chapter 6 rules the additional pass through events that are to apply to Country Energy for the next regulatory control period are the:

- retail project event
- smart meter event
- emissions trading scheme event
- aviation hazards event
- general nominated pass through event

as defined in section 15.6 of this final decision.

In accordance with clause 6.12.1(14) of the transitional chapter 6 rules the additional pass through events that are to apply to EnergyAustralia for the next regulatory control period are the:

- retail project event
- smart meter event
- emissions trading scheme event
- general nominated pass through event

as defined in section 15.6 of this final decision.

In accordance with clause 6.12.1(14) of the transitional chapter 6 rules the additional pass through events that are to apply to Integral Energy for the next regulatory control period are the:

- retail project event
- smart meter event
- emissions trading scheme event
- general nominated pass through event

as defined in section 15.6 of this final decision.

16 Revenue requirements

16.1 Introduction

This chapter sets out the AER's consideration of issues raised in response to the draft decision, and its calculation of annual revenue requirements for each NSW DNSP, for the provision of standard control services for each year of the next regulatory control period. This chapter also sets out X factor values used to calculate the weighted average price caps (WAPC) to apply to the standard control services provided by each NSW DNSP.

16.2 AER draft decision

16.2.1 Approach to setting X factors

The AER noted that each of the NSW DNSPs had proposed large X factors and associated price increases, particularly for 2009–10, which raised concerns among several stakeholders.[1017] The AER noted that the requirements of clause 6.5.9 of the transitional chapter 6 rules provided the AER and the NSW DNSPs with the opportunity to explore the possibility of reducing potential price shocks in the first year of the next regulatory control period.[1018] The AER therefore applied the effects of its draft decision through a reduction in the size of the X factors to be applied in 2009–10 by each NSW DNSP.[1019]

16.2.2 Country Energy

The draft decision resulted in a total revenue requirement over the next regulatory control period of $5819 million ($nominal) as set out in table 16.1, compared to $5978 million proposed by Country Energy. This difference reflected:

- a $196 million reduction to opex
- a $68.4 million increase in the regulatory depreciation building block reflecting changes to standard life assumptions
- a $34.8 million reduction to the return on capital.

[1017] AER, *Draft decision*, p. 294.
[1018] AER, *Draft decision*, p. 296.
[1019] AER, *Draft decision*, pp. 305, 307–308.

Table 16.1: AER draft decision on Country Energy's revenue requirements and X factors ($m nominal)

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

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

16.2.3 EnergyAustralia

The draft decision resulted in total revenue requirements over the next regulatory control period of $994 million ($nominal) for transmission and $8453 million ($nominal) for distribution, compared to $1040 million and $8969 million respectively proposed by EnergyAustralia as set out in tables 16.2 and 16.3. The difference in the combined revenue requirements mainly reflected:

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

Table 16.2: AER draft decision on EnergyAustralia's revenue requirements and X factors – distribution ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		70.8	94.1	114.6	136.3	131.0
Return on capital		699.9	828.6	966.4	1121.5	1263.5
Tax allowance		36.1	64.3	73.8	84.8	89.6
Operating expenditure		478.1	504.5	534.7	567.0	594.0
Annual revenue requirements		1284.8	1491.5	1689.4	1909.5	2078.2
Expected revenues	1023.7	1296.7	1469.5	1670.4	1886.6	2138.0
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–24.30	–10.43	–10.43	–10.43	–10.43

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

Table 16.3: AER draft decision on EnergyAustralia's revenue requirements and X factors – transmission ($m, nominal)

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

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

16.2.4 Integral Energy

The AER's draft decision resulted in a total revenue requirement over the next regulatory control period of $4632 million ($nominal) as set out in table 16.4, compared to $4695 million proposed by Integral Energy. This difference reflected:

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

- reductions to capex and opex due to the application of revised real cost escalations.

Table 16.4: AER draft decision on Integral Energy's revenue requirements and X factors ($m, nominal)

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

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

16.3 Revised regulatory proposals

16.3.1 Country Energy

Country Energy's revised regulatory proposal included a total revenue requirement over the next regulatory control period of $6278 million ($nominal) as set out in table 16.5, which is $460 million more than the draft decision.

Table 16.5: Country Energy's revised regulatory proposal revenue requirements and X factors ($m nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		152.0	175.1	139.6	162.1	183.3
Return on capital		432.7	503.6	573.9	652.4	730.7
Tax allowance		45.3	51.9	45.6	53.6	59.2
Operating expenditure		421.2	454.3	479.5	504.9	530.1
TUOS adjustment		–72.7	–	–	–	–
Annual revenue requirements		978.5	1184.9	1238.6	1373.0	1503.3
Expected revenues	753.2	970.2	1097.7	1242.2	1405.9	1591.5
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–24.61	–9.50	–9.50	–9.50	–9.50

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

Country Energy proposed X factors of –24.61 per cent (i.e. a real increase) for the first year of the regulatory control period and –9.50 per cent for subsequent years. In doing so it noted that it had based its calculation on the methodology used by the AER in its draft decision for comparability purposes.[1020] These X factors result in the net present values (NPVs) of the revenue requirements and expected revenues being equal over the next regulatory control period as shown in table 16.6. The resulting difference between the annual revenue requirement and expected revenue in the final year of the period is $88.2 million or 5.86 per cent.

Table 16.6: Country Energy's proposed annual revenue requirements and expected revenues ($m, nominal)

	NPV	2009–10	2010–11	2011–12	2012–13	2013–14
Annual revenue requirements	4650.9	978.5	1184.9	1238.6	1373.0	1503.3
Expected revenues	4650.9	970.2	1097.7	1242.2	1405.9	1591.5
Difference (%)	0.00	–0.85	–7.36	–0.29	2.40	5.86

Source: Country Energy, confidential PTRM.

Key features of Country Energy's revised revenue requirements, relative to the draft decision, included:

- a $252 million increase in the proposed opex allowance

[1020] Country Energy, *Revised regulatory proposal*, p. 74.

- a $173 million increase in the return on capital, reflecting a higher weighted average cost of capital (WACC) (10.15 per cent compared to the draft decision of 9.72 per cent)
- slowing growth in forecast energy sales (0.44 per cent per year, compared with 1.56 per cent per year in the draft decision) which, when combined with the reinstatement of revenue requirements, required corresponding increases in average prices and therefore X factors.

16.3.2 EnergyAustralia

EnergyAustralia's revised regulatory proposal included a total revenue requirement over the next regulatory control period for both transmission and distribution networks of $10235 million ($nominal) as set out in tables 16.7 and 16.8, which is $787 million more than the draft decision.

Table 16.7: EnergyAustralia's revised regulatory proposal revenue requirements and X factors – distribution ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		71.2	94.1	114.6	136.2	132.0
Return on capital		745.9	893.3	1037.2	1192.6	1339.8
Tax allowance		39.8	41.5	79.8	90.7	95.8
Operating expenditure		535.8	569.5	602.2	638.9	667.1
Annual revenue requirements		1392.7	1598.5	1833.7	2058.3	2234.7
Expected revenues	1025.5	1392.7	1531.7	1776.6	2055.8	2396.1
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–39.29	–14.29	–14.29	–14.29	–14.29

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

Table 16.8: EnergyAustralia's revised regulatory proposal revenue requirements and X factors – transmission ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		3.4	6.7	10.3	13.5	12.5
Return on capital		107.4	138.7	157.9	185.6	222.8
Tax allowance		3.4	6.7	10.3	13.5	12.5
Operating expenditure		40.9	42.4	43.7	45.6	46.6
Annual revenue requirements		155.4	191.6	221.0	255.5	293.8
Expected revenues	129.5	155.4	184.0	217.8	257.8	305.2
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–17.08	–15.43	–15.43	–15.43	–15.43

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

EnergyAustralia's X factors result in the NPVs of the revenue requirements and expected revenues for both transmission and distribution services being equal over the next regulatory control period, with variances in expected and required revenues in the final year being 3.90 per cent and 7.22 per cent as shown in table 16.9.

EnergyAustralia stated that the X factors in the draft decision led to an increase in the variance between expected revenue and the revenue requirement in the final year of the regulatory control period. It was concerned that the AER's approach was 'driven by stakeholder concerns at the expense of moving away from the intention of the transitional chapter 6 rules which is to minimise variance in revenues in the final year.'[1021]

[1021] EnergyAustralia, *Revised regulatory proposal*, p. 115.

Table 16.9: EnergyAustralia's proposed annual revenue requirements and expected revenues ($m, nominal)

	NPV	2009–10	2010–11	2011–12	2012–13	2013–14
Transmission						
Annual revenue requirements	819.0	155.4	191.6	221.0	255.5	293.8
Expected revenues	819.0	155.4	184.0	217.8	257.8	305.2
Difference (%)	0.00	0.00	-3.95	-1.45	0.90	3.90
Distribution						
Annual revenue requirements	6729.4	1392.7	1598.5	1833.7	2058.3	2234.7
Expected revenues	6729.4	1392.7	1531.7	1776.6	2055.8	2396.1
Difference (%)	0.00	0.00	-4.18	-3.12	-0.12	7.22

Source: EnergyAustralia confidential PTRM.

Key features of EnergyAustralia's revised regulatory proposal revenue requirements, relative to the draft decision, included:

- a $382 million increase in the proposed opex allowance
- a $411 million increase in the return on capital, reflecting a higher WACC (10.15 per cent compared to the draft decision of 9.72 per cent)
- significant declines in forecast energy sales, particularly for the first two years of the regulatory control period (e.g. a –3.22 per cent decline in energy sales in 2009–10, compared to the increase of 1.66 per cent in the draft decision), which resulted in corresponding increases in average prices and therefore X factors to ensure the recovery of revenue requirements.

16.3.3 Integral Energy

Integral Energy's revised regulatory proposal included a total revenue requirement over the next regulatory control period of $4916 million ($nominal) as set out in table 16.10, which is $284 million more than the draft decision.

Table 16.10: Integral Energy's revised regulatory proposal revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		164.7	129.4	130.3	114.6	118.1
Return on capital		381.8	429.0	482.3	529.9	575.0
Tax allowance		41.5	42.9	45.0	42.7	46.6
Operating expenditure		303.8	313.5	327.9	343.4	353.7
Annual revenue requirements		891.8	914.8	985.5	1030.7	1093.3
Expected revenues	652.8	795.7	879.2	975.8	1096.9	1220.5
Forecast CPI (%)		2.55	2.55	2.55	2.55	2.55
X factors[a] (%)		–19.50	–6.95	–6.95	–6.95	–6.95

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

Integral Energy proposed X factors of –19.50 per cent (i.e. a real increase) for the first year of the next regulatory control period and –6.95 per cent for subsequent years. This results in the NPVs of the revenue requirements and expected revenues being equal over the next regulatory control period as shown in table 16.11. The resulting difference between the annual revenue requirement and expected revenue in the final year of the period is $127 million or 11.63 per cent.

Table 16.11: Integral Energy's revised proposed annual revenue requirements and expected revenues ($m, nominal)

	NPV	2009–10	2010–11	2011–12	2012–13	2013–14
Annual revenue requirements	3687.9	891.8	914.8	985.5	1030.7	1093.3
Expected revenues	3687.9	795.7	879.2	975.8	1096.9	1220.5
Difference (%)	0.00	–10.78	–3.89	–0.99	6.42	11.63

Source: Integral Energy confidential PTRM.

Key features of Integral Energy's revised regulatory proposal revenue requirements, relative to the draft decision, include:

- a $89.3 million increase in the proposed depreciation allowance, reflecting the re-instatement of $170 million of 'omitted' assets in its RAB that were not allowed for in the AER's draft decision
- a $106 million increase in the return on capital, reflecting a higher WACC (10.02 per cent compared to the draft decision of 9.72 per cent)

- declines in sales forecasts for the first (and to a lesser extent, the second) year of the next regulatory control period, requiring relatively higher average prices (and X factors) to ensure the recovery of revenue requirements.

16.4 Submissions

Submissions by the Energy Markets Reform Forum (EMRF), Public Interest Advocacy Centre (PIAC), Energy Users Association of Australia (EUAA), Anglicare and the City of Sydney all noted or expressed concerns about the significant increases in prices resulting from the NSW DNSPs' revised regulatory proposals.

The EMRF and EUAA urged the AER to be cognisant of the negative impact of increases in network charges on users in the context of deteriorating economic conditions, and other energy cost pressures arising from policies aimed at reducing reliance on non–renewable energy sources.[1022]

The EUAA considered there was a lack of transparency in how the regulatory process ensures tariffs are cost reflective, and suggested the AER consider tightening its oversight of this process to ensure that no cross subsidies were adopted into tariff design.[1023] It also sought clarification from the AER on whether it would act to create more certainty for users in dealing with increases in distribution prices.[1024]

The PIAC considered that the AER and the NSW DNSPs should model the full cost increase to different household classes of the NSW DNSP's proposed price increases as well as the other factors driving up electricity prices (e.g. the effects of any carbon emissions trading scheme, increases in transmission and retail charges, and the costs of drawing wholesale electricity from more expensive peaking generation plant). PIAC suggested this modelling should use up–to–date inputs and the data should be made available in the final decision.[1025]

Anglicare submitted a study of the circumstances of customers receiving Energy Accounts Payment Assistance (EAPA). The study was conducted to better understand the difficulties faced by low-income households in meeting their energy costs. Based on the findings of this study, Anglicare submitted several recommendations including:

- a low income household impact study should be undertaken before any rises in the price of electricity are approved
- ongoing price regulation of electricity is essential if low income households are to be guaranteed equity of access to electricity consumption
- compensatory measures for price rises, such as one off assistance to households to introduce more energy efficient systems to their home
- increased funding for the EAPA program

1022 EUAA, *Submission to the AER's draft decision and revised DNSP proposals,* pp. 5-6, 12; EMRF, *AER draft decision— A response by the Energy Markets Reform Forum,* p. 8.
1023 EUAA, p. 7.
1024 EUAA., p. 9.
1025 PIAC, pp. 2-3.

- the development of a 'no disconnections' policy in NSW that would require retailers to proactively inform customers about the forms of assistance they can access.[1026]

In an addendum to its main submission, Anglicare raised concerns regarding the introduction of smart meters and time of use (TOU) pricing, recommending that ToU tariffs be subjected to a proper analysis.[1027] The factors that Anglicare suggested should be considered by such an analysis included the ability of certain households to respond to ToU tariffs and the impacts of ToU tariffs on low income households. Anglicare also suggested that there needed to be an educational program for customers to accompany the introduction of ToU tariffs.[1028]

The City of Sydney recommended that the AER report on the implications of its determination for typical residential and business customers' bills over the full period of the determination.[1029] It noted that the proposed network price increases would particularly affect disadvantaged customers.[1030]

Country Energy, Integral Energy and EnergyAustralia submitted letters to the AER requesting it to consider an alternative approach to setting X factors, given the implications of the global financial crisis for network customers.[1031] In early April, each of the NSW DNSPs proposed that the AER consider the possibility of reducing the magnitude of X factors in the first year or years of the next regulatory control period, in accordance with the transitional chapter 6 rules' requirements and in seeking an appropriate balance between price impacts and the need to provide adequate funding for investments. EnergyAustralia noted that such an alternative approach to setting X factors would not affect its ability to deliver its proposed operating or capital investment plans.[1032]

Country Energy also provided an updated estimate of the balance of its transmission use of system (TUOS) overs and unders account as at 30 June 2009 ($44.9 million), to be deducted from its building block allowance in 2009–10.[1033] When taking this estimate into account, along with its suggestion of an alternative approach to setting X factors, Country Energy proposed X factors of roughly equal value for years 1 to 4 of the next regulatory control period, combined with a price decrease in the final year to align expected and required revenues for that year.

16.5 AER considerations

The following sections address the issue of X factors and price impacts, and then subsequently address each of the building blocks proposed by each NSW DNSP. Further details on the AER's consideration of the NSW DNSPs' proposed opex, corporate income tax and depreciation are contained in chapters 8, 9 and 10 respectively of this final

1026 Anglicare, *Submission in Relation to Energy Price and Low Income Households*, p. 5.
1027 Anglicare, *Addendum to the Anglicare Sydney Submission*, p. 1.
1028 Anglicare., p. 2.
1029 City of Sydney, *Submission to the Australian Energy Regulator on the NSW Draft Distribution Network Pricing Determination 2009–2014*, p. 1.
1030 City of Sydney., p. 2.
1031 Country Energy, *Letter to the AER*, 8 April 2009; Integral Energy, *Letter to the AER*, 7 April 2009; EnergyAustralia, *Letter to the AER*, 6 April 2009.
1032 EnergyAustralia, *Letter to the AER*, 14 April 2009.
1033 Country Energy, *Letter to the AER*, 8 April 2009.

decision. The return on capital using the WACC determined in chapter 11 of this final decision is outlined below.

16.5.1 Proposed X factors and price impacts

Clause 6.5.9 of the transitional chapter 6 rules requires the AER to set X factors subject to the following requirements:

- they must be set with regard to each NSW DNSPs' total revenue requirement for the next regulatory control period
- they must be set to minimise, as far as possible, the variance between the annual revenue requirement and expected revenue in the final year of the next regulatory control period
- they must be set to equalise, in NPV terms, the total revenue requirement and expected revenues over the next regulatory control period under the applicable form of control.

Clause 6.5.9(c) of the transitional chapter 6 rules also provides for different X factors to be set for each regulatory year.

In the context of stakeholder concerns and the NSW DNSPs' later submissions, the AER has considered the price impacts of various X factors and options to address this under clause 6.5.9 of the transitional chapter 6 rules.

At the request of the NSW DNSPs, the AER held further discussions with them on possible scenarios in setting X factors. The AER's considerations in setting X factors, including outcomes of these discussions, are:

- clause 6.5.9(b)(3) of the transitional chapter 6 rules represents a 'strict' requirement for the NPVs of expected revenues and the annual revenue requirements to be equal
- while the NSW DNSPs generally preferred expected revenues to align with annual revenue requirements, they recognised the need to address potential price shocks in the earlier years of the regulatory control period
- to provide for a deferral of price increases would likely result in the NSW DNSPs under–recovering their annual revenue requirements earlier in the next regulatory control period, requiring a corresponding over–recovery of revenues later in that period
- the AER did not consider it appropriate to provide for a price decrease in the final year of the next regulatory control period (following several large price increases) for the sole purpose of realigning expected revenues with annual revenue requirements
- in the draft decision, the AER considered that variances of up to 3.5 per cent between expected revenues and the revenue required in the final year of the next regulatory control period were reasonable under clause 6.5.9(b)(2) of the transitional chapter 6 rules.

These considerations are applied on a business specific basis in section 16.6.

With regards to further pricing analysis suggested by PIAC and Anglicare, the AER considers that its examination of price impacts for end use customers in this final decision is intended to be generally applicable to the typical customer connected to each NSW

DNSP's network. Further analysis of expected price trends for individual customers, including with respect to other possible impacts on energy costs, is beyond the scope of this final decision. The AER notes that the NSW DNSPs submitted expected prices for each year of the next regulatory control period with their regulatory proposals in June 2008, as required by the AER's regulatory information notice and templates, and in accordance with clause 6.8.2(c)(4) of the transitional chapter 6 rules. The AER will consider ways to make this information more accessible to users as part of future review processes to provide more certainty to users.

Regarding the comments made by the EUAA and the EMRF on the various other issues affecting users' energy costs, the AER does not have any explicit powers to consider or make judgements on the overall 'reasonableness' of prices that result from its decision, nor to make associated adjustments to regulated revenues. The AER has assessed each element of the NSW DNSPs' regulatory proposals and revised regulatory proposals without any preconceived notion of what might be regarded as acceptable price increases.

The AER also does not have any role in managing any price changes or making compensatory measures for disadvantaged users. The AER has, however, been able to use its discretion in deferring some price shocks through the setting of X factors as discussed above.

Regarding comments by Anglicare and the EUAA with respect to specific tariff issues, the AER will conduct an analysis of all prices proposed by the NSW DNSPs for 2009–10 under part I of the transitional chapter 6 rules when they are submitted in May 2009. For tariffs to be approved they will need to reflect (amongst other things) the principles in clause 6.18.5 of the transitional chapter 6 rules, which require prices to reflect marginal cost and to be free of cross subsidies.

16.5.2 Country Energy

Asset base roll forward and indexation

As discussed in chapter 5 of this final decision, the AER has determined the opening value of Country Energy's RAB to be $4319 million ($nominal) as at 1 July 2009. Based on this opening value, the AER has modelled Country Energy's RAB over the next regulatory control period using the PTRM and as shown in table 16.12.

Table 16.12: AER forecast roll–forward of Country Energy's regulatory asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	4319.4	4929.7	5563.3	6272.7	6986.6
Net capex[a]	764.4	810.3	850.9	875.0	917.1
Indexation of opening RAB	106.9	122.0	137.7	155.2	172.9
Straight-line depreciation	–261.0	–298.7	–279.2	–316.4	–353.7
Closing RAB	4929.7	5563.3	6272.7	6986.6	7722.9

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. Note this capex also includes equity raising costs (see section 8.5.6 for details).

The transitional chapter 6 rules require that the roll forward of Country Energy's RAB as at the end of each year of the next regulatory control period, be calculated by taking the opening RAB value, adjusting it for inflation, adding any additional capex, and subtracting disposals and depreciation for the year. The closing RAB value for one year then becomes the opening RAB value for the following year.

The AER has determined that the method for indexing Country Energy's RAB for each year of the next regulatory control period will be the same as that used to escalate its WAPC for that relevant year—that is, to apply the percentage change in the sum of four quarters to December consumer price index (CPI), all groups weighted average of eight capital cities, published by the Australian Bureau of Statistics (ABS). This method will be used to roll forward Country Energy's RAB for the purposes of the AER's distribution determination for the regulatory control period commencing on 1 July 2014.

Return on capital

The AER considers that Country Energy's proposed return on capital has been calculated in accordance with the PTRM, however it notes that this amount is affected by the AER's conclusions regarding other inputs to the PTRM, namely the opening RAB and capex allowance determined by the AER in chapters 5 and 7 of this final decision.

The AER has determined the annual return on capital allowance by applying the WACC to Country Energy's opening RAB for each year of the next regulatory control period. This amount is outlined in table 16.20.

The nominal vanilla WACC of 8.78 per cent is based on a post–tax nominal return on equity of 10.29 per cent and a pre–tax nominal return on debt of 7.78 per cent. These figures are calculated using observed market data as at 20 February 2009.

Depreciation

Using a post–tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the regulatory control period and to determine the depreciation allowance. Table 16.20 sets out the resulting figures for Country Energy.

Estimated taxes payable

Using the PTRM, the AER has modelled Country Energy's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than Country Energy's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause 6.5.3 of the transitional chapter 6 rules, 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 25.97 per cent for this final decision. Table 16.13 sets out the AER's estimate of Country Energy's tax payments.

Table 16.13: AER modelling of net tax allowance for Country Energy ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Tax payable	87.9	93.0	78.5	91.3	100.2
Value of imputation credits	–43.9	–46.5	–39.2	–45.6	–50.1
Net tax allowance	43.9	46.5	39.2	45.6	50.1

Operating and maintenance expenditure

As discussed in chapter 8, the AER has determined a forecast opex allowance for Country Energy of $2211 million ($nominal) during the next regulatory control period. Table 16.20 sets out the annual opex allowance, which equates to an average amount of $442 million per annum in nominal terms.

Revenue decrements arising from previous periods' control mechanisms

The AER notes that Country Energy's latest estimate of the balance of its TUOS overs and unders account as at 30 June 2009 is $44.9 million.[1034] As per the approach accepted in the draft decision, the AER has deducted this amount from Country Energy's revenue requirement for 2009–10. This will need to be reflected by Country Energy when proposing adjustments for TUOS recoveries in its pricing proposal for 2009–10.

[1034] Country Energy, *Letter to the AER*, 8 April 2009.

16.5.3 EnergyAustralia

EnergyAustralia's PTRM contains separate building block calculations for the purposes of creating X factors for the forms of control applying to its distribution services (WAPC) and transmission services (revenue cap). The AER has examined the amendments made by EnergyAustralia and considers the resulting calculations to be consistent with its PTRM.[1035]

Asset base roll forward and indexation

As discussed in chapter 5, the AER has determined the opening value of EnergyAustralia's transmission and distribution RABs as at 1 July 2009 to be $1028 million ($nominal) and $7297 million ($nominal) respectively. Based on these opening values, the AER has modelled EnergyAustralia's RABs over the next regulatory control period using the PTRM and as shown in tables 16.14 and 16.15.

Table 16.14: AER forecast roll–forward of EnergyAustralia's transmission regulatory asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	1028.5	1308.5	1488.6	1745.9	2090.6
Net capex[a]	284.0	187.5	268.2	359.0	228.8
Indexation of opening RAB	25.5	32.4	36.8	43.2	51.7
Straight-line depreciation	–29.5	–39.8	–47.8	–57.5	–65.2
Closing RAB	1308.5	1488.6	1745.9	2090.6	2306.0

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. Note this capex also includes equity raising costs (see section 8.5.6 for details).

[1035] AER, *Final decision, Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–14: Post–tax revenue model,* Canberra, January 2008, Appendix B.

Table 16.15: AER forecast roll–forward of EnergyAustralia's distribution regulatory asset base ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	7297.2	8433.0	9707.1	11 130.9	12 511.2
Net capex	1211.8	1373.6	1543.9	1522.6	1643.7
Indexation of opening RAB	180.6	208.7	240.2	275.5	309.6
Straight-line depreciation	–256.6	–308.2	–360.3	–417.8	–448.0
Closing RAB	8433.0	9707.1	11 130.9	12 511.2	14 016.5

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. Note this capex also includes equity raising costs (see section 8.5.6 for details).

The transitional chapter 6 rules require that the roll forward of EnergyAustralia'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.

The AER has determined that the method for indexing EnergyAustralia's transmission and distribution RABs for each year of the next regulatory control period will be the same as that used to escalate the respective forms of control (MAR and WAPC) for that relevant year. For distribution assets, this will be the percentage change in the sum of four quarters to December CPI, all groups weighted average of eight capital cities, published by the ABS. For transmission assets, this will be the annual percentage change in the same CPI measure to March quarter. These calculations will be used in the roll forward calculations in the AER's distribution determination for the regulatory control period commencing on 1 July 2014.

Return on capital

The AER considers that EnergyAustralia's proposed return on capital has been calculated in accordance with the PTRM, however it notes that this amount has been affected by its conclusions regarding other inputs to the PTRM, namely the opening RAB and capex allowance determined by the AER in chapters 5 and 7 of this final decision.

The AER has determined the annual return on capital allowance by applying the WACC to EnergyAustralia's opening transmission and distribution RABs for each year of the next regulatory control period. This amount is outlined in tables 16.23 and 16.24.

The nominal vanilla WACC of 8.78 per cent is based on a post–tax nominal return on equity of 10.29 per cent and a pre–tax nominal return on debt of 7.78 per cent. These figures are calculated using observed market data as at 20 February 2009.

Depreciation

Using a post–tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the regulatory control period and to determine the depreciation allowance. Tables 16.23 and 16.24 set out the resulting depreciation allowances for EnergyAustralia's distribution and transmission networks.

Estimated taxes payable

Using the PTRM, the AER has modelled EnergyAustralia's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than EnergyAustralia's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause 6.5.3 of the transitional chapter 6 rules, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Under the post–tax nominal framework, the application of the statutory tax rate generates an effective tax rate that can provide more appropriate and cost–reflective revenue outcomes. The effective tax rate is defined as the difference between pre–tax and post–tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Based on the approach to modelling the cash flows in the PTRM and using inputs from this final decision, the AER has derived effective tax rates for EnergyAustralia's distribution and transmission networks of 28.65 per cent and 23.77 per cent respectively. Tables 16.16 and 16.17 show the AER's estimate of EnergyAustralia's tax payments for distribution and transmission respectively.

Table 16.167: AER modelling of net tax allowance – EnergyAustralia distribution ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Tax payable	62.9	116.8	133.1	151.0	157.7
Value of imputation credits	–31.5	–58.4	–66.5	–75.5	–78.9
Net tax allowance	31.5	58.4	66.5	75.5	78.9

Table 16.17: AER modelling of net tax allowance – EnergyAustralia transmission ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Tax payable	5.1	12.3	14.4	17.1	18.3
Value of imputation credits	–2.6	–6.2	–7.2	–8.5	–9.2
Net tax allowance	2.6	6.2	7.2	8.5	9.2

Operating and maintenance expenditure

As discussed in chapter 8, the AER has determined a forecast opex allowance for EnergyAustralia's distribution and transmission networks of $2832 million ($nominal) during the next regulatory control period. Tables 16.23 and 16.24 show the annual opex allowances for distribution and transmission respectively.

16.5.4 Integral Energy

Asset base roll forward and indexation

The transitional chapter 6 rules require that the roll forward of Integral Energy's RAB, as at the end of each year of the next regulatory control period, be calculated by taking the opening RAB value, adjusting it for inflation, adding any additional capex, and subtracting disposals and depreciation for the year. The closing RAB value for one year then becomes the opening RAB value for the following year.

As discussed in chapter 5, the AER has determined the opening value of Integral Energy's RAB to be $3690 million ($nominal) as at 1 July 2009. Based on this opening value, the AER has modelled Integral Energy's RAB over the next regulatory control period using the PTRM and as shown in table 16.18.

Table 16.18: AER forecast roll–forward of Integral Energy's regulatory asset base ($m nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Opening RAB	3690.0	4148.6	4685.1	5166.1	5611.6
Net capex[a]	603.0	659.7	600.8	558.9	548.7
Indexation of opening RAB	91.3	102.7	115.9	127.9	138.9
Straight-line depreciation	–235.6	–225.9	–235.7	–241.2	–245.0
Closing RAB	4148.6	4685.1	5166.1	5611.6	6054.2

Note: The straight-line depreciation less the inflation adjustment on the opening RAB provides the regulatory depreciation building block allowance.

(a) In accordance with the timing assumptions of the PTRM, the nominal capex values include a half WACC allowance to compensate for the average six-month period before capex is added to the RAB for revenue modelling purposes. Note this capex also includes equity raising costs (see section 8.5.6 for details).

The transitional chapter 6 rules require that the roll forward of Integral Energy's RAB as at the end of each year of the next regulatory control period, be calculated by taking the opening RAB value, adjusting it for inflation, adding any additional capex, and subtracting disposals and depreciation for the year. The closing RAB value for one year then becomes the opening RAB value for the following year.

The AER has determined that the method for indexing Integral Energy's RAB for each year of the next regulatory control period will be the same as that used to escalate its WAPC for that relevant year—that is, to apply the percentage change in the sum of four quarters to December CPI, all groups weighted average of eight capital cities, published by the ABS. This method will be used to roll forward Integral Energy's RAB for the purposes of the AER's distribution determination for the regulatory control period commencing on 1 July 2014.

Return on capital

The AER considers that Integral Energy's proposed return on capital has been calculated in accordance with the PTRM, however it notes that this amount has been affected by its conclusions regarding other inputs to the PTRM, namely the opening RAB and capex allowance determined by the AER in chapters 5 and 7 of this final decision.

The AER has determined the annual return on capital allowance by applying the WACC to Integral Energy's opening RAB for each year of the next regulatory control period. This amount is outlined in table 16.27.

The nominal vanilla WACC of 8.83 per cent is based on a post–tax nominal return on equity of 10.32 per cent and a pre–tax nominal return on debt of 7.84 per cent. These figures are calculated using observed market data as at 20 March 2009.

Depreciation

Using a post–tax nominal framework, the AER has made allowances for nominal regulatory depreciation—also referred to as the return of capital—that sums the (negative) straight–line depreciation and the (positive) annual inflation effect on the opening RAB. Regulatory depreciation is used to model the nominal asset values over the regulatory control period and to determine the depreciation allowance. Table 16.27 sets out the resulting figures.

Estimated taxes payable

Using the PTRM, the AER has modelled Integral Energy's benchmark income tax liability during the next regulatory control period based on the tax depreciation and cash flow allowances provided in this final decision. The amount of tax payable is estimated using 60 per cent benchmark gearing, rather than Integral Energy's actual gearing, and a statutory company income tax rate of 30 per cent. In accordance with clause 6.5.3 of the transitional chapter 6 rules, the value of imputation credits (gamma) of 0.5 has been applied when calculating the net tax allowance.

Under the post–tax nominal framework, the application of the statutory tax rate generates an effective tax rate that can provide more appropriate and cost–reflective revenue outcomes. The effective tax rate is defined as the difference between pre–tax and post–tax rates of return. It is sensitive to several factors, including the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Based on the approach to modelling the cash flows in the PTRM, the AER has derived an effective tax rate of 28.83 per cent for this final decision. Table 16.19 sets out the AER's estimate of Integral Energy's tax payments.

Table 16.19: AER modelling of net tax allowance for Integral Energy ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Tax payable	69.7	76.9	76.2	74.6	74.9
Value of imputation credits	–34.9	–38.4	–38.1	–37.3	–37.5
Net tax allowance	34.9	38.4	38.1	37.3	37.5

Operating and maintenance expenditure

As discussed in chapter 8, the AER has determined a forecast opex allowance for Integral Energy of $1634 million ($nominal) during the next regulatory control period. Table 16.27 shows the annual opex allowance, which equates to an average amount of $327 million per annum in nominal terms.

16.6 AER conclusion

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

Country Energy

The final decision results in a total revenue requirement over the next regulatory control period of $5672 million as set out in table 16.20, compared to $6278 million proposed by Country Energy. The main reasons for this difference reflect:

- the $179 million reduction to opex
- a $428 million reduction to the return on capital, reflecting the AER's decision on Country Energy's WACC

Table 16.20: AER conclusion on Country Energy's annual revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		154.1	176.7	141.5	161.1	180.8
Return on capital		379.4	433.0	488.6	550.9	613.6
Tax allowance		43.9	46.5	39.2	45.6	50.1
Operating expenditure		405.4	424.0	442.8	461.2	477.9
TUOS adjustment		–44.9				
Annual revenue requirements		937.9	1080.2	1112.2	1218.9	1322.4
Expected revenues	732.3	856.8	1000.0	1153.0	1329.7	1370.4
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–13.41	–13.31	–12.00	–12.00	0.00

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

The AER saw merit in Country Energy's proposed approach of having X factors of similar value for years one to four of the regulatory control period as this would smooth out price shocks in the initial years. However, as noted in section 16.5.1, the AER considered that it would be an unusual outcome for users to face a series of relatively large price increases and then a price decrease in the final year of the next regulatory control period in order to align expected and required revenues in the final year of the next regulatory control period. Accordingly, the AER's decision is to generally maintain Country Energy's approach but allow for prices to remain constant in real terms for the final year of the next regulatory control period. The X factors required to equate expected revenues and revenue requirements in NPV terms under this approach are outlined in table 16.20.

The AER considers that Country Energy's X factors have been set to minimise as far as practicable, in the context of stakeholder preferences, the difference between expected and required revenues in the final year of the next regulatory control period. These differences are outlined in table 16.21.

Table 16.21: AER conclusion on Country Energy's annual revenue requirements and expected revenues ($m, nominal)

	NPV	2009–10	2010–11	2011–12	2012–13	2013–14
Annual revenue requirements	4377.4	937.9	1080.2	1112.2	1218.9	1322.4
Expected revenues	4377.4	856.8	1000.0	1153.0	1329.7	1370.4
Difference (%)	0.00	–8.64	–7.42	3.67	9.09	3.63

The resulting impact in terms of end use prices of the AER's decision to use these X factors, compared with Country Energy's proposal, is outlined in table 16.22.

Table 16.22: End use price impacts – Country Energy proposal and AER decision (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Country Energy proposal	9.85	4.31	4.53	4.74	4.96
AER final decision	5.36	5.77	5.54	5.88	0.00

Note: Calculations assume distribution costs contribute 40 per cent to end user bills.

EnergyAustralia

The final decision results in total revenue requirements over the next regulatory control period of $7843 million ($nominal) for distribution and $943 million ($nominal) for transmission as set out in tables 16.23 and 16.24, compared to $9118 million and $1117 million respectively proposed by EnergyAustralia. This reflects an overall difference of $1449 million in nominal revenue requirements for the combined transmission and distribution networks, and is mainly comprised of:

- a $401 million reduction to opex
- a $1037 million reduction to the return on capital, reflecting the AER's decision to apply a WACC of 8.78 per cent, compared to EnergyAustralia's proposed WACC of 10.16 per cent.

Table 16.23: AER conclusion on EnergyAustralia's annual revenue requirements and X factors – distribution ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		76.0	99.5	120.1	142.3	138.4
Return on capital		640.9	740.7	852.6	977.6	1098.9
Tax allowance		31.5	58.4	66.5	75.5	78.9
Operating expenditure		483.1	506.4	530.8	554.6	570.6
Annual revenue requirements		1231.4	1404.9	1570.0	1750.1	1886.7
Expected revenues	1023.5	1224.3	1382.7	1562.7	1758.7	1924.6
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–17.86	–12.00	–12.00	–12.00	–8.00

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

Table 16.24: **AER conclusion on EnergyAustralia's annual revenue requirements and X factors – transmission ($m, nominal)**

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		4.0	7.4	10.9	14.2	13.5
Return on capital		90.3	114.9	130.7	153.3	183.6
Tax allowance		2.6	6.2	7.2	8.5	9.2
Operating expenditure		35.9	36.5	37.3	38.3	38.5
Annual revenue requirements		132.8	165.0	186.2	214.4	244.7
Expected revenues	129.5	143.0	162.6	185.0	210.4	239.3
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–7.77	–11.00	–11.00	–11.00	–11.00

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

Regarding the X factors for EnergyAustralia's distribution and transmission network businesses, the AER sought to reduce the size of the X factor in year one while also considering that the annual revenue requirements for both network businesses increase at a relatively high rate. The AER considered a variety of scenarios and decided that the values in tables 16.23 and 16.24 adequately address stakeholder preferences to manage potential price shocks in the initial years of the next regulatory control period, as well as comply with the requirements of clause 6.5.9 of the transitional chapter 6 rules.

The AER's decision is to reduce EnergyAustralia's proposed X factors in 2009–10 from –39.29 per cent to –17.86 per cent for distribution, and from –17.08 per cent to –7.77 per cent for transmission. X factors for the remaining years have also decreased as a result of the final decision. The AER considers that EnergyAustralia's X factors have been set to minimise as far as practicable, in the context of stakeholder preferences, the difference between expected and required revenues in the final year of the next regulatory control period. These differences are outlined in table 16.25.

Table 16.25: AER conclusion on EnergyAustralia's annual revenue requirements and expected revenues ($m, nominal)

	NPV	2009–10	2010–11	2011–12	2012–13	2013–14
Transmission						
Annual revenue requirements	719.9	132.8	165.0	186.2	214.4	244.7
Expected revenues	719.9	143.0	162.6	185.0	210.4	239.3
Difference (%)	0.00	7.66	–1.45	–0.65	–1.86	–2.20
Distribution						
Annual revenue requirements	6027.0	1231.4	1404.9	1570.0	1750.1	1886.7
Expected revenues	6027.0	1224.3	1382.7	1562.7	1758.7	1924.6
Difference (%)	0.00	–0.58	–1.58	–0.46	0.49	2.01

The final decision X factors for EnergyAustralia's distribution network translate into a real increase of 7.15 per cent in end users' bills in 2009–10, an average of 5.26 per cent for each subsequent year of the next regulatory control period as set out in table 16.26.

Table 16.26: End use price impacts – EnergyAustralia proposal and AER final decision (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Distribution					
EnergyAustralia proposal	15.72	6.88	7.36	7.83	8.30
AER final decision	7.15	5.28	5.62	5.96	4.20
Transmission					
EnergyAustralia proposal	0.85	0.90	1.02	1.17	1.34
AER final decision	0.39	0.59	0.65	0.72	0.79

Note: Calculations assume distribution and transmission costs contribute 40 per cent and 5 per cent to end user bills respectively.

Integral Energy

The final decision results in a total revenue requirement over the next regulatory control period of $4485 million ($nominal) as set out in table 16.27, compared to $4916 million ($nominal) proposed by Integral Energy. The main reasons for this difference reflect:

- removal of the $170 million from Integral Energy's opening RAB, affecting mainly the depreciation and return on capital building blocks

- a $339 million reduction to the return on capital, which largely reflects the AER's decision to apply a WACC of 8.83 per cent, compared to a WACC of 10.02 per cent proposed by Integral Energy.

Table 16.27: AER conclusion on Integral Energy's annual revenue requirements and X factors ($m, nominal)

	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Regulatory depreciation		144.3	123.2	119.7	113.4	106.1
Return on capital		326.0	366.5	413.9	456.4	495.8
Tax allowance		34.9	38.4	38.1	37.3	37.5
Operating expenditure		304.8	314.8	327.4	339.7	346.8
Annual revenue requirements		809.9	843.0	899.2	946.8	986.1
Expected revenues	652.8	749.9	828.4	919.0	984.8	1024.3
Forecast CPI (%)		2.47	2.47	2.47	2.47	2.47
X factors[a] (%)		–12.58	–7.00	–7.00	–2.00	0.00

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

In deciding on Integral Energy's X factors the AER notes that the increases in revenue requirements resulting from its decision were relatively lower than for Country Energy and EnergyAustralia. By contrast, the sales forecasts accepted by the AER displayed declines early in the next regulatory control period with small increases thereafter. The X factor scenarios considered by the AER therefore all involved progressively lower X factors over the next regulatory control period in order to meet the requirements of clause 6.5.9 of the transitional chapter 6 rules and also to reduce price shocks in earlier years. The AER considers that Integral Energy's X factors have been set to minimise as far as practicable, in the context of stakeholder preferences, the difference between expected and required revenues in the final year of the next regulatory control period. This difference is illustrated in table 16.28.

Table 16.28: AER conclusion on Integral Energy's annual revenue requirements and expected revenues ($m nominal)

	NPV	2009–10	2010–11	2011–12	2012–13	2013–14
Annual revenue requirements	3474.0	809.9	843.0	899.2	946.8	986.1
Expected revenues	3474.0	749.9	828.4	919.0	984.8	1024.3
Difference (%)	0.00	–7.41	–1.73	2.20	4.02	3.87

The resulting impact in terms of end use prices of the AER's decision to use these X factors, compared with Integral Energy's proposal, is outlined in table 16.29 below.

Table 16.29: End use price impacts – Integral Energy revised regulatory proposal and AER final decision (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Integral Energy proposal	7.80	3.08	3.20	3.31	3.43
AER decision	5.03	3.00	3.12	0.92	0.00

Note: Calculations assume distribution costs contribute 40 per cent to end user bills.

The annual revenue requirements for each year of the next regulatory control period for each NSW DNSP are set out in table 16.30.

Table 16.30: AER conclusion on NSW DNSPs annual revenue requirements ($m, nominal)

	2009–10	2010–11	2011–12	2012–13	2013–14
Country Energy	937.9	1080.2	1112.2	1218.9	1322.4
EnergyAustralia (distribution)	1231.4	1404.9	1570.0	1750.1	1886.7
EnergyAustralia (transmission)	132.8	165.0	186.2	214.4	244.7
Integral Energy	809.9	843.0	899.2	946.8	986.1

The X factors for each year of the next regulatory control period for each NSW DNSP are set out in table 16.31.

Table 16.31: AER conclusion on NSW DNSPs' X factors (per cent)

	2009–10	2010–11	2011–12	2012–13	2013–14
Country Energy	–13.41	–13.41	–12.00	–12.00	0.00
EnergyAustralia (distribution)	–17.86	–12.00	–12.00	–12.00	–8.00
EnergyAustralia (transmission)	–7.77	–11.00	–11.00	–11.00	–11.00
Integral Energy	–12.58	–7.00	–7.00	–2.00	0.00

16.7 AER final decision

In accordance with clause 6.12.1(2)(i) of the transitional chapter 6 rules the AER refuses to approve the annual revenue requirement proposed by Country Energy.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the X factors to apply to Country Energy are as specified in table 16.31 of this final decision.

In accordance with clause 6.3.2(a)(1) of the transitional chapter 6 rules Country Energy's annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.30 of this final decision.

In accordance with clause 6.3.2(a)(2) of the transitional chapter 6 rules an appropriate methodology for indexation of Country Energy's regulatory asset base is as specified in section 16.5.2 of this final decision.

In accordance with clause 6.3.2(a)(5) of the transitional chapter 6 rules the other amounts, values or inputs on which Country Energy's building block determination is based are as specified in sections 16.5 and 16.6 of this final decision.

In accordance with clause 6.12.1(2)(i) of the transitional chapter 6 rules the AER refuses to approve the annual revenue requirement for distribution proposed by EnergyAustralia.

In accordance with clause 6.12.1(2)(i) of the transitional chapter 6 rules the AER refuses to approve the annual revenue requirement for transmission proposed by EnergyAustralia.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the distribution X factors to apply to EnergyAustralia are as specified in table 16.31 of this final decision.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the transmission X factors to apply to EnergyAustralia are as specified in table 16.31 of this final decision.

In accordance with clause 6.3.2(a)(1) of the transitional chapter 6 rules EnergyAustralia's distribution annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.30 of this final decision.

In accordance with clause 6.3.2(a)(1) of the transitional chapter 6 rules EnergyAustralia's transmission annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.30 of this final decision.

In accordance with clause 6.3.2(a)(2) of the transitional chapter 6 rules the appropriate methodologies for indexation of EnergyAustralia's transmission and distribution regulatory asset bases are as specified in section 16.5.3 of this final decision.

In accordance with clause 6.3.2(a)(5) of the transitional chapter 6 rules the other amounts, values or inputs on which EnergyAustralia's building block determination is based are as specified in sections 16.5 and 16.6 of this final decision.

In accordance with clause 6.12.1(2)(i) of the transitional chapter 6 rules the AER refuses to approve the annual revenue requirement proposed by Integral Energy.

In accordance with clause 6.12.1(11) of the transitional chapter 6 rules the X factors to apply to Integral Energy are as specified in table 16.31 of this final decision.

In accordance with clause 6.3.2(a)(1) of the transitional chapter 6 rules Integral Energy's annual revenue requirement for each regulatory year of the next regulatory control period is as set out in table 16.30 of this final decision.

In accordance with clause 6.3.2(a)(2) of the transitional chapter 6 rules an appropriate methodology for indexation of Integral Energy's regulatory asset base is as specified in section 16.5.4 of this final decision.

In accordance with clause 6.3.2(a)(5) of the transitional chapter 6 rules the other amounts, values or inputs on which Integral Energy's building block determination is based are as specified in sections 16.5 and 16.6 of this final decision.

17 Alternative control (public lighting) services

This chapter sets out the AER's consideration of issues raised in response to its draft decision and supplementary draft decision on alternative control (public lighting) services. It sets out the AER's decision on the fixed prices for public lighting services for 2009–10 and the price path to be applied to these prices for the remainder of the next regulatory control period. It also sets out how the AER will determine compliance with the control mechanism during the next regulatory control period.

17.1 Introduction

The transitional chapter 6 rules divide direct control services into standard control services and alternative control services and set out the provisions the AER must apply in regulating alternative control services.

According to clause 6.2.3B(b)(1) of the transitional chapter 6 rules, the services classified by IPART as excluded distribution services are deemed to be classified as an alternative control service for the next regulatory control period. Those services classified by IPART as excluded distribution services are the construction and maintenance of public lighting infrastructure. Under the regulatory arrangements administered by IPART, the construction and maintenance of public lighting infrastructure was treated as an excluded distribution service regulated under the Excluded Distribution Services Rule.

IPART defined public lighting infrastructure as:[1036]

> The structures, wiring, globes and other equipment:
>
> (1) used for, or associated with, the provision of public lighting to streets, roads and other public places; and
>
> (2) which are connected or attached to (or which form part of) a DNSPs distribution system (as that term is defined in the determination).

In January 2006, the NSW Department of Energy, Utilities and Sustainability (DEUS) (now the NSW Department of Water and Energy) introduced a voluntary code of practice for a range of public lighting services in NSW (the Public Lighting Code). Its purpose was to clarify the relationship between public lighting service providers and customers, and to that end sets out some benchmarks to assist customers. Relevantly, under the Public Lighting Code, 'Public Lighting' is defined as covering 'lighting schemes for the generality of roads and outdoor public area (for example, parks, reserves, pedestrian zones, footpaths, cycle paths, car parks and other public areas) that are managed by or on behalf of a Customer'. The Public Lighting Code defines a 'Customer' as 'a Council (as defined by the *Local Government Act 1993*), or Local, State or Federal Government agency that has authority over areas with Public Lighting'.[1037]

As part of the transfer of regulatory functions from IPART to the AER in February 2008, the AER issued a statement regarding the form of regulatory control mechanism to apply to public lighting.[1038] The AER concluded that public lighting would be subject to a fixed

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[1036] IPART, Regulation of Excluded Distribution Services Rule 2004, annexure 1, pp. 103–104.
[1037] DEUS, *NSW Public lighting code*, pp. 10–11.
[1038] AER, *Statement on control mechanisms for alternative control services for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008.

schedule of prices for the first year of the next regulatory control period (based on revenues determined from a limited building block approach) and a price path for the remaining years of the regulatory control period.[1039]

In June 2008, the NSW DNSPs submitted their regulatory proposals to the AER for the next regulatory control period. The proposals included a submission on public lighting charges.

17.2 AER draft decision

In the draft decision, the AER identified the following issues associated with the public lighting proposals submitted by the NSW DNSPs:

- the current pricing schedules did not reflect the actual cost of providing public lighting services as comparable prices were charged for new and aged assets
- construction and maintenance costs were not reflective of their current price schedules, nor was it possible to reconcile data on the disparity between construction and maintenance costs between the NSW DNSPs
- there was considerable uncertainty about the condition and age of public lighting assets
- there was evidence that some customers were cross subsidising other customers.

The AER considered that it was not desirable to pursue a form of regulatory control over public lighting where these issues were not adequately addressed. For this reason, the AER considered that it was necessary to revise its approach to regulating alternative control (public lighting) services to ensure that the regime provided transparency and certainty to customers while also allowing the NSW DNSPs access to a fair rate of return on their investment. In accordance with clause 6.12.1(12) of the transitional chapter 6 rules, the AER amended the control mechanism for alternative control services to:

- a schedule of fixed prices in the first year of the next regulatory control period for assets constructed before 1 July 2009 developed using a building block approach
- a schedule of fixed prices in the first year of the next regulatory control period for assets constructed after 30 June 2009 developed using an annuity capital charge approach
- a price path, such as CPI, for the remaining years of the next regulatory control period.

The AER required each NSW DNSP to resubmit its proposed prices by 16 January 2009, consistent with the revised approach. The draft decision also set out a proposed timetable for development and consultation on a supplementary draft decision setting out the AER's view on the revised prices and price paths proposed by the NSW DNSPs.

Integral Energy and Country Energy provided the AER with their revised prices consistent with the draft decision in January 2009. However, EnergyAustralia did not provide revised prices in its January submission as it did not consider that the AER's

[1039] AER, *Statement on control mechanisms for alternative control services for the ACT and NSW*, February 2008, pp. 4–5.

reasons for rejecting its annuity method contained in its June 2008 proposal were appropriate or robust.[1040] EnergyAustralia was requested by the AER to provide prices consistent with the AER's revised approach, which it subsequently provided in late January 2008.

17.3 AER supplementary draft decision

On 16 March 2009 the AER published its supplementary draft decision which included the AER's assessment of the NSW DNSPs' submissions on public lighting prices and price paths.

The proposed tariff classes and designations as set out in the supplementary draft decision are shown in table 17.1.

Table 17.1: AER supplementary draft decision public lighting tariffs

Tariff class	Description	Basis of tariff determination
Assets constructed prior to 1 July 2009		
1	Capital funded by DNSP	Annual efficient maintenance charge. Capital charge based on IPART approved RAB.
2	Capital not funded by DNSP	Annual efficient maintenance costs. DNSP not entitled to a return on or of capital.
Assets constructed after 30 June 2009		
3	Capital funded by DNSP	Annual efficient maintenance charge (same as those for tariff class 2). Annual capital charge (return of and on) based on efficient material and installation costs.
4	Capital not funded by DNSP	Annual efficient maintenance charge (same as those for tariff class 2). DNSP not entitled to a return on or of capital.
5	Capital funded by the DNSP but asset replaced at the request of the customer before the end of its economic life.	Tariff based on annual efficient maintenance charge (discount provided on maintenance costs if asset replacement is aligned with the DNSPs bulk maintenance cycle). Annual capital charge is to be based on whether or not the DNSP has funded the capital (that is, potentially tariff class 3). Residual asset charge calculated for replaced asset based on remaining life determined through an assessment of the assets condition or the AER default value.

Source: AER, *Supplementary draft decision*, p. 51.

Submissions on the supplementary draft decision closed on 27 March 2009. The AER received 11 submissions from stakeholders in response to the supplementary draft decision. The list of parties who made submissions is at appendix U.

[1040] EnergyAustralia, *Submission on public lighting*, contained in its revised regulatory proposal, 14 January 2009, p. 173.

Organisations representing NSW councils expressed concern about the proposed price increases under the AER's arrangements and considered that there remained large unexplained differences between the proposed costs of the NSW DNSPs.

Councils were particularly concerned that in the supplementary draft decision, the AER accepted prices for energy efficient lighting that they considered would make their uptake uneconomical. The councils also considered that as monopoly service providers, the NSW DNSPs should disclose their underlying modelling and cost information associated with public lighting.

Councils also expressed concerns over the structure and funding of the NSW DNSPs' opening regulatory asset bases (RAB), the standard and remaining lives of public lighting assets, the calculation of depreciation charges and the assumptions associated with the calculation of maintenance costs.

Integral Energy supported the consultative approach that the AER had taken but noted that the supplementary draft decision differed from Integral Energy's position on a number of key assumptions. Integral Energy reiterated its position on these matters.

Country Energy considered that the reductions in prices for tariffs 1, 2 and 4 were realistic and reasonable but did not support the reductions proposed for tariff 3. Country Energy's overall observation was that the supplementary draft decision may be based upon unrealistic expectations about the extent of achievable cost reductions.

EnergyAustralia does not agree with the draft decision or its supplementary draft decision for a number of reasons, including that it considers the AER has not given adequate consideration to the information provided by EnergyAustralia and has unreasonably substituted its own inputs and assumptions. It also considers that the AER has not provided EnergyAustralia with a reasonable opportunity to recover at least efficient costs.[1041]

17.4 General issues

A number of general issues were raised by both stakeholders and the NSW DNSPs that did not fall within the categories of maintenance charges, the building block approach or the annuity approach. These issues are discussed in the following sections.

17.4.1 AER review process

Submissions

The Trans Tasman Energy Group (TTEG) made a submission on behalf of a number of NSW councils.[1042] It stated that it was not aware of any opportunity within the regulations for the AER to review costs during the next regulatory control period. However, it submitted that due to the pricing uncertainties that exist within the supplementary draft decision, the AER should consider exploring alternatives to enable further sector

[1041] EnergyAustralia, *Submission on AER's public lighting supplementary draft decision,* 3 April 2009, p. 5.
[1042] The councils were Blacktown City Council, Blue Mountains City Council, Fairfield City Council, Liverpool City Council, Penrith City Council and the Hills Shire Council.

participation in establishing efficient public lighting charges for the next regulatory control period.[1043]

AER considerations

The AER has undertaken a rigorous review involving a thorough consultation process. In establishing efficient charges for public lighting assets the AER has made public, where possible, information on the key assumptions underlying the NSW DNSP's models to allow informed submissions from interested parties. While interested parties have differing views about what particular assumptions and inputs should be, the AER considers that the prices and charges established are at efficient levels. Notwithstanding this, TTEG correctly notes that the transitional chapter 6 rules do not allow the AER to review its distribution determination part way through the next regulatory control period.

Conclusion

The transitional chapter 6 rules do not allow the AER to review its distribution determination part way through the next regulatory control period.

17.4.2 Negotiable components of public lighting services

Given that the construction and maintenance of public lighting infrastructure will be a direct control service for the next regulatory control period, the AER is of the view that components of that service (including, without limitation, its prices and charges) can be negotiable components for the purposes of part DA of the transitional chapter 6 rules and, therefore, they can be negotiated in accordance with the framework set out in chapter 3 of this final decision. The AER has decided, however, that prices and charges for the construction and maintenance of public lighting infrastructure can only be negotiated below (but not above) the prices and charges for the service which are set out in this final decision.

17.4.3 Revised tariff classes and tariff class designations

AER draft decision

In its draft decision, the AER set out six tariff classes relating to public lighting assets. Tariff classes 1 and 2 related to assets constructed before 1 July 2009 and tariff classes 3, 4 and 5 related to assets constructed after 30 June 2009. Tariff class 6 related to the early replacement of assets at a customer's request.[1044]

Revised regulatory proposals

Country Energy stated that the tariff class designations should reflect varying arrangements for the funding of public lighting assets and that funding arrangements determined whether capital charges are applicable. It submitted that capital charges currently are and should continue to be based solely on whether the capital costs for public lighting assets were provided by the DNSP or the customer (regardless of ownership). Country Energy suggested that tariff classes 4 and 5 of the draft decision could be merged.[1045]

[1043] TTEG, *Submission on the supplementary draft decision*, March 2009, p. 4.
[1044] AER, *Draft decision*, pp. 340–341.
[1045] Country Energy, *Revised regulatory proposal*, pp. 77–78.

Integral Energy also considered that the key factor in terms of designating tariffs was whether the capital was funded by the DNSP or the customer.[1046] It stated its preference would be that the current designation of 'asset owned and constructed by the customer' be replaced with 'capital not funded by DNSP' and the current designation of 'asset owned and constructed by the DNSP' be replaced with 'capital funded by the DNSP'.

Integral Energy also noted that the AER's tariff class 5 referred to assets owned by the customer but maintained by the DNSP. Integral Energy stated that it considered public lighting maintenance to be contestable and therefore unregulated. On this basis Integral Energy did not propose a tariff class 5.[1047]

AER supplementary draft decision

The AER agreed with Integral Energy and Country Energy that the designation of a tariff class should be determined by who funded the capital for the asset as ownership did not always indicate this.

Submissions

Riverina Eastern Regional Organisation of Councils (REROC) stated that for councils on the new tariff class 2 there did not appear to be provisions in place for the council to engage DNSPs to replace the lights. It stated that future replacement of tariff 2 lights is a monopoly service, particularly in its region. REROC considered that the cost for replacement lighting should therefore be an explicit part of the final determination.[1048]

REROC considered it imperative that an additional tariff is included in the determination covering installation only by a DNSP, where the capital cost is met by the council and the DNSP provides the labour. It stated that the replacement light would be gifted to the DNSP and included on the DNSP's inventory for maintenance purposes. REROC stated that such a tariff would then allow a council to weigh the costs and benefits of continuing to fund the capital component of the new lights or of moving to the AER's tariff class 3.[1049]

TTEG supported the AER's approach to recognising tariff classes determined by funding rather than ownership. However, it noted that the price lists provided by the NSW DNSPs were complicated and could benefit from rationalisation.[1050]

AER considerations

The AER agrees with Integral Energy and Country Energy that the designation of a tariff class should be determined by who funded the capital.

With respect to an installation only tariff, the provision of public lighting has been defined as an alternative control service, with the potential for the development of competition. There is nothing to prevent a customer from engaging an accredited contractor, other than the NSW DNSPs, to supply, install and/or maintain a public lighting asset.

[1046] Integral Energy, *Public lighting pricing proposal to the AER*, table 1, p. 3.
[1047] Integral Energy, *Public lighting pricing proposal to the AER*, table 1, p. 3.
[1048] REROC, *Submission on the supplementary draft decision*, 27 March 2009. p. 5.
[1049] REROC, p. 5.
[1050] TTEG, *Submission to the AER in response to draft determination 2009-14 alternative controls (public lighting)*, March 2009, p. 4.

However, the AER acknowledges that there is not a great depth in the supply of providers capable of these delivering services at present. This occurs for a number of reasons ranging from the large scale and scope inherent in the DNSPs, the lack of accredited providers or simply the fact that many accredited providers may already be on sub-contract arrangements with the DNSPs.

Notwithstanding, the AER does acknowledge that there is a certain level of benefit to promoting competition by allocating a price to each component of a light's installation as it creates niches in the market. However, this level of disaggregation needs to be balanced against creating a cumbersome and costly regime to administer.

The AER considers that establishing maximum charges for constructing and maintaining a public lighting asset is a sufficient level of disaggregation to encourage potential entrants to provide either or both services and in publishing maximum charges establishes the market entry price.

As the next regulatory control period progresses the AER will endeavour to monitor how the market for the construction and maintenance of public lighting assets develops. Based on these observations, the AER may review the disaggregation of charges as part of the next distribution determination for the NSW DNSPs.

In the interim, the AER does not consider that it is necessary to provide an installation only tariff.

In terms of identifying the capital charge for public lighting, customers can obtain this charge by subtracting tariff class 4 from tariff class 3.

AER conclusion

For the reasons set out above, the AER maintains its supplementary draft decision regarding the designation of tariff classes. The tariff classes to apply to the alternative control services provided by the NSW DNSPs are set out in table 17.2.

Table 17.2: AER conclusion on public lighting tariffs and their determination

Tariff class	Description	Basis of tariff determination
Assets constructed prior to 1 July 2009		
1	Capital funded by DNSP	Annual efficient maintenance charge. Capital charge based on IPART approved RAB.
2	Capital not funded by DNSP	Annual efficient maintenance costs. DNSP not entitled to a return on or of capital.
Assets constructed after 30 June 2009		
3	Capital funded by DNSP	Annual efficient maintenance charge (same as those for tariff class 2). Annual capital charge (return of and on) based on efficient material and installation costs.
4	Capital not funded by DNSP	Annual efficient maintenance charge (same as those for tariff class 2). DNSP not entitled to a return on or of capital.
5	Capital funded by the DNSP but asset replaced at the request of the customer before the end of its economic life.	Tariff calculated by the DNSP at the time of agreement to replace the asset early using an agreed method for determining the residual capital value of the asset. The charge is to be paid up front. Residual asset charge calculated for replaced asset based on remaining life determined through an assessment of the assets condition and/or type or the AER default value.

17.4.4 Proposed price increases

AER supplementary draft decision

In terms of assets constructed before 1 July 2009, the AER estimated that the average charge for councils in Country Energy's and EnergyAustralia's networks in 2009–10 would be reduced on average by 33 per cent and 6 per cent respectively, compared with 2008–09 charges, while charges for Integral Energy's councils would increase by 4 per cent. The AER acknowledged that because the new regime establishes a cost reflective basis for charges, the outcomes for individual customers would vary.[1051]

In terms of new public lighting assets, the AER noted that the proposed prices for 2009–10 were 22 per cent, 10 per cent and 2 per cent lower on average than those proposed by Country Energy, EnergyAustralia and Integral Energy respectively.[1052]

Submissions

A large number of councils expressed concern about EnergyAustralia's proposed price increases relative to their current prices and charges. In addition, with respect to EnergyAustralia's proposed pricing for energy efficient lighting, South Sydney Regional Organisation of Councils (SSROC) considered that there were large unexplained

[1051] AER, media release, 13 March 2009.
[1052] AER, media release, 13 March 2009.

differences between the proposed costs for these lights and other less energy efficient lighting types between EnergyAustralia and other utilities.[1053]

EnergyAustralia stated that significant price increases were necessary to achieve cost reflectivity for public lighting services and added that councils were free to tender for public lighting services as they were not monopoly services.[1054] In addition, EnergyAustralia considered that the AER had deliberately chosen parameters to deliver the lowest prices for customers without sufficient regard to the costs in providing the service.[1055]

Campbelltown City Council stated that consideration should be given to ensuring that energy efficient lighting is not priced out as a viable option for upgrading less efficient luminaire types. It considered that the price differential between the T5 twin 14 watt (2 * 14W) luminaire and the less efficient equivalent 80 watt mercury vapour (80W MV) luminaire created a disincentive for the uptake of the more energy efficient luminaires.[1056]

TTEG supported the proposed reductions in charges for 2009–10 but proposed that tariffs must be further reduced to reflect fair and reasonable costs.[1057]

AER considerations

With respect to the increase in public lighting charges, the AER recognises that in achieving cost reflectivity and removing cross–subsidies there may be some re–balancing of tariffs which has resulted in price increases for certain customers.

While the AER recognises that customers would prefer not to incur price increases, the AER also considers that it is important that cross–subsidies are removed and that public lighting prices reflect the efficient cost of supply.

The AER examines the key drivers of maintenance costs and the differences in energy efficient lighting charges between Victoria and NSW in section 17.5.

AER conclusion

In section 17.6.4.9, the AER has examined price path options. The schedule of charges applicable to customers is discussed further in that section.

17.4.5 Information disclosure

AER supplementary draft decision

The supplementary draft decision contained data on the NSW DNSPs' capital costs, times to construct assets and labour rates.[1058]

1053 SSROC, *Submission on the supplementary draft decision*, 27 March 2009, p. 2.
1054 EnergyAustralia, *Response to stakeholders' submissions*, 6 March 2009, pp. 31–33.
1055 EnergyAustralia, *Submission on the supplementary draft decision*, 3 April 2009, p. 9.
1056 Campbelltown City Council, *Submission on the supplementary draft decision*, 27 March 2009, p. 1.
1057 TTEG, *Submission on the supplementary draft decision*, March 2009, p. 7.
1058 AER, *Supplementary draft decision*, sections 3.3, 3.4, 4.1, 4.2, 4.3 and 4.5

Submissions

SSROC considered that as a monopoly service provider, EnergyAustralia should disclose its underlying modelling, including key assumptions and cost information associated with public lighting.[1059]

EnergyAustralia indicated that it had provided a large amount of information to the AER in response to information requests. While the schedules of prices contained in the supplementary draft decision were derived using this data, EnergyAustralia noted that these outcomes were not part of its regulatory proposal. It stated that incorrect representations were made in some areas of the supplementary draft decision.[1060]

In addition, EnergyAustralia considered that the AER had not followed the steps set in the NEL regarding disclosure of confidential information and requested that certain information be removed from the supplementary draft decision on confidentiality grounds.[1061]

AER considerations

The AER considers a fundamental element of regulatory decision making is providing sufficient information to allow stakeholders to make informed contributions to the decision making process.

The AER must balance the needs of stakeholders to have more information, against the confidentiality requests made by network service providers. In this regard, the AER is disappointed that EnergyAustralia claimed confidentiality over information that both Integral Energy and Country Energy were prepared to make public. The AER considers that in the absence of competitive pressures, the NSW DNSPs should give greater consideration to their customers in an effort to ensure that they understand the basis on which their prices have been developed and to allow them to make informed submissions to the AER.

In the absence of full disclosure of information, the AER considers that the next best option is ensuring regulatory accountability through transparency of its own regulatory processes. The AER is hopeful that this will provide customers a degree of comfort that the information the AER has relied upon is both credible and consistent.

With respect to the misrepresentation of information, the AER accepts EnergyAustralia’s claim that the AER had not been clear in stating that while the price paths were derived using data requested by the AER, this information did not form part of EnergyAustralia’s regulatory proposal.

AER conclusion

The AER has accepted EnergyAustralia’s request for confidentiality over certain information but notes that neither Country Energy nor Integral Energy sought confidentiality over the same information. The AER also accepts that it had misrepresented certain data related to EnergyAustralia’s proposal and has rectified this matter in this final decision. Overall, the AER considers that the NSW DNSPs need to

[1059] SSROC, *Submission on the supplementary draft decision*, 27 March 2009, p. 11.
[1060] EnergyAustralia, *Submission on the supplementary draft decision*, p. 6.
[1061] EnergyAustralia, letter to the AER, 25 March 2009, pp. 2–3.

give greater consideration to ensuring that their customers understand the basis on which their prices have been developed.

17.4.6 Distribution use of system charges

AER supplementary draft decision

This issue was not discussed in the the supplementary draft decision.

Submissions

SSROC stated that EnergyAustralia had substantially increased its proposed network distribution charges for public lighting in its revised regulatory proposal. SSROC considered that public lighting was held to a very different and substantially lower reliability service standard than that for general network customers and for that reason, distribution network charges for public lighting may represent an inappropriate cross subsidy from public lighting customers to other classes of customers.[1062]

By way of example, SSROC noted that:[1063]

- public lighting supply interruptions are explicitly excluded from current network reliability measures
- reliability on EnergyAustralia's network is measured in minutes while public lighting reliability is measured in days
- there is no regulated reliability target for NSW public lighting with provisions of only limited effectiveness in the voluntary NSW Public Lighting Code.

SSROC stated that customers are still expected to pay for the full cost of public lighting, even in the case of prolonged public lighting outages.[1064]

SSROC also stated that, as a result of requests from councils, EnergyAustralia recently adopted default replacement lighting choices that will see a steady decline in the overall energy consumption of public lighting, with load expected to decline by approximately 35 per cent. However, SSROC considered that EnergyAustralia is proposing that public lighting customers cross subsidise other network customers for capex resulting from load growth that is not attributable to public lighting.[1065]

Another issue raised by SSROC related to councils access to a particular EnergyAustralia network tariff for council owned installations that have a load profile similar to public lighting. SSROC stated that the tariff definition for tariff 401 is 'available for metered and unmetered supplies that are deemed to have a similar usage profile to public lighting and have some form of on/off control'. It stated that, in practice, councils have been unable to

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1062 SSROC, *Submission on the draft decision and EnergyAustralia's revised regulatory proposal*, 12 February 2009, p. 8.

1063 SSROC stated that the NSW Public Lighting Code requires a minimum of 95 per cent availability at any given point in time but there is no penalty for failing to meet the availability standard. It also noted that the Code requires DNSPs to repair public lighting within an average of 8 working days of the fault being reported and that a $15 dollar penalty applies if the repair has not been completed in 12 working days. SSROC, *Submission on the draft decision and EnergyAustralia's revised regulatory proposal*, pp. 8–9.

1064 SSROC, *Submission on the draft decision and EnergyAustralia's revised regulatory proposal*, 12 February 2009, p. 9.

1065 SSROC, *Submission on the draft decision and EnergyAustralia's revised regulatory proposal*, pp. 9–10.

access this tariff and have been placed on the more expensive general supply tariff. SSROC considered this to be a significant barrier to consideration of competitive alternatives in the limited cases where councils are able to manage their own lighting independent of the distribution network poles (for example, parks, squares and certain underground-supplied installations).[1066]

AER considerations

The AER has considered the issues raised by SSROC. It understands that increasing distribution network charges are an important issue for public lighting customers and acknowledges that EnergyAustralia's distribution network charges will increase significantly over the next regulatory control period. The key drivers behind these increases include enhanced reliability targets and growth in maximum demand. The AER considers that public lighting customers should overall benefit from improvements in the reliability of the distribution network and therefore it is appropriate that they contribute to the costs associated with it. Nevertheless, given the prolonged outages experienced by public lighting customers, the AER considers that more robust service level arrangements need to be implemented.

The AER also notes SSROC's argument that public lighting customers are inappropriately subsidising other customers for increases in capex due to forecast increases in load growth when SSROC expects load growth associated with public lighting to decline over the next and subsequent regulatory control periods. The pricing arrangements under the NER require that revenues associated with the efficient costs of operating and maintaining the network be recovered from all users through network prices. This is on the basis that the network is a shared service. The AER also notes that network prices are partly based on consumption and therefore customers who consume less energy should receive lower overall charges compared to those whose consumption levels are increasing. The AER's assessment of the capex proposed by each of the NSW DNSPs and the potential impact on an average customer's prices is set out in chapters 7 and 16 respectively of this final decision.

In relation to tariff 401, the AER agrees that this appears to be a barrier to councils' consideration of developing council–owned lighting and could potentially raise issues of competitive neutrality. Nevertheless, the AER's role is to establish the efficient charges to apply to public lighting services. While the broader determination involves establishing the total revenues that NSW DNSPs are permitted to recover from their customers, the AER only makes a decision on distribution network prices after the release of its final distribution determination. The AER considers that the onus is on EnergyAustralia to provide the requested network tariff to its customers or otherwise explain to them why the tariff is not applicable to their particular circumstances.

AER conclusion

The pricing arrangements in the NER require that revenues associated with the efficient costs of operating and maintaining the network to mandated reliability levels be recovered from all users through network prices. In relation to tariff 401, the onus is on EnergyAustralia to provide the requested network tariff to its customers or otherwise explain to them why the tariff is not applicable to their particular circumstances.

[1066] SSROC, *Submission on the draft decision and EnergyAustralia's revised regulatory proposal*, p.10.

17.4.7 Perceived overlap with IPART pricing decision

Submissions

Both Blacktown City Council and The Hills Shire Council stated that on 21 December 2007, Integral Energy made a submission to IPART for an increase in its public lighting charges which equated to a 5.5 per cent increase from 1 February 2008 with further increases totalling 14.4 per cent over a five year period. Both councils stated that they made allowances in their budgets for the approved 5.5 per cent increase, noting that the remaining balance of 8.9 per cent would follow over 4 years commencing 2009–10. However, they stated that it appears that a further increase of 11 per cent for Blacktown City Council and 24 per cent for the Hills Shire Council for 2009–10 is now being recommended by the AER. They consider the price increases to be unreasonable, particularly if they are passed on in one year.[1067]

AER considerations

In respect to the claims made by Blacktown City Council and the Hills Shire Council, on 31 March 2009 the AER wrote to Integral Energy concerning the issues raised by the councils. Integral provided the following response:[1068]

> At the 2004 Determination IPART defined public lighting as an Excluded Service and determined that the public lighting prices would be regulated under Rule 2004/1 – Regulation of Excluded Distribution Services. Integral's understanding of these arrangements was that the public lighting prices that existed as at 1 July 2004 would remain in place until such time as Integral made an application for a price change under Rule 2004/1.
>
> On 1 June 2007 Integral lodged a pricing proposal seeking a CPI + 2% increase. As part of the pricing proposal Integral indicated that public lighting revenue of approximately $14m was below the cost reflective revenue by approximately $2m. It was never stated but the revenue was approximately 14% below cost reflective level and this may have been verbally communicated to Councils as part of the consultation process on the new prices. It should be noted that the 14% under cost reflective levels was based on the pricing models that existed at the time and are not reflective of the annuity based approach proposed by the AER. On 21 December 2007 Integral lodged a revised public lighting proposal for the CPI + 2% increase in public lighting prices. IPART approved a 5.5% (CPI + 2%) increase on 29 February 2008 which took effect from 1 March 2008. Integral did not propose a price path over the regulatory period.
>
> The 1 March 2008 prices are the current public lighting prices which remain in force until such time as the AER makes its final determination on the new prices to apply from 1 July 2009.

The AER has reviewed the submissions from Blacktown City Council and the Hills Shire Council, Integral Energy's response to the AER on this issue and IPART's statement of reasons.[1069] The AER notes that IPART approved Integral Energy's application to increase its prices by 5.5 per cent from 1 March 2008 but did not approve any further increases over the subsequent 4 years. Based on Integral Energy's comments, the 14 per cent increase referred to by the councils appear to have resulted from discussions between

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[1067] Blacktown City Council, *Submission on the supplementary draft decision*, 23 March 2009; and the Hills Shire Council, *Submission on the supplementary draft decision*, undated.

[1068] Integral Energy, email to AER, response to questions on public lighting, 2 April 2009.

[1069] IPART, *Statement of Reasons for Decision*, 27 February 2008.

the councils and Integral Energy representatives concerning price increases that could potentially occur over the subsequent five year period.

The AER acknowledges the concerns raised by Blacktown City Council and the Hills Shire Council concerning the price increases being proposed by the AER. The AER's considerations regarding smoothing of charges for existing assets can be found in section 17.6.4.9 of this final decision.

AER conclusion

IPART approved Integral Energy's December 2007 application for a 5.5 per cent nominal price increase but did not approve any increases for subsequent years. IPART's approved pricing increases will apply until the AER's final distribution determination takes effect. From 1 July 2009 the AER's determination on the prices and charges for public lighting services will take affect.

17.4.8 Comparisons between NSW DNSPs

AER supplementary draft decision

In the absence of meaningful external data against which to compare the NSW DNSPs proposed capital and maintenance costs, the AER made direct comparisons between the NSW DNSPs. In doing so, the AER was able to observe differences in costs and practices to obtain an understanding of efficient cost levels.

Submissions

EnergyAustralia considered that different circumstances apply to the provision of public lighting services in each franchise area and that there are often different individually negotiated supplier contracts, different component offerings and geographical considerations. For these reasons, it considered direct comparison of cost data across the NSW DNSPs was not meaningful. It stated that the presence of different costs was not an indicator that a price is inefficient or inappropriate.[1070]

Country Energy stated that its network is not comparable with other DNSPs in NSW or Victoria and that, as a result of its dispersed geographic area, it has higher costs at every stage relative to a more concentrated network.[1071]

The TTEG queried whether least cost should be considered for all DNSPs or at least a cost approaching lowest cost. It questioned why customers should be penalised if DNSPs are not purchasing at the lowest cost, or somewhere near it.[1072]

AER considerations

The AER considers it is practical and sensible to directly compare the performance of the NSW DNSPs against one another, on the basis that direct comparison provides a reasonable gauge of the NSW DNSPs' respective efficiency. In doing so, the AER accepts that public lighting services in each distribution area are different for a number of reasons including geographical and operating environment considerations.

[1070] EnergyAustralia, *Submission on supplementary draft decision*, 27 March 2009, pp. 9–10.
[1071] Country Energy, *Submission on supplementary draft decision*, 27 March 2009, pp. 7–8.
[1072] TTEG, *Submission on the supplementary draft decision*, p. 2.

In making comparisons, the AER has been mindful of these differences rather than simply identifying and applying the lowest cost of performing an activity. The objective of the AER is to ensure that each NSW DNSP is provided with only efficient costs for their specific circumstances. For example, in terms of Country Energy's maintenance costs the AER has allowed premiums on top of benchmark rates, recognising the geographical spread of its network and the additional storage costs that result from that operating environment. While this means that Country Energy is not at lowest cost, the AER considers it is at an efficient cost, given its operating environment.

AER conclusion

In making comparisons between the NSW DNSPs, the AER has been mindful of the differences rather than identifying and applying least costs. The AER's objective is to provide each DNSP with efficient costs for their particular circumstances.

17.5 Maintenance charges

The following section addresses issues raised in response to the derivation of the maintenance charge (tariffs 2 and 4) as presented in the supplementary draft decision.

There are four key components that influence how the maintenance charge is calculated:

1. the length of the cycle between bulk lamp replacements
2. the number of lamps that can be replaced per day under a bulk lamp replacement regime
3. the expected spot (intermittent) lamp failures between bulk lamp replacements and the relationship between the length of a bulk lamp replacement cycle and the number of spot lamp failures
4. the number of spot lamp replacements that can be completed per day.

17.5.1 Issues and considerations

17.5.1.1 Bulk lamp replacement cycles

AER supplementary draft decision

In its supplementary draft decision, the AER considered that a 3 year cycle for bulk lamp replacement was appropriate. The AER required EnergyAustralia to remodel its maintenance charges using a 3 year bulk lamp replacement cycle rather than a 2.5 year cycle.[1073]

Submissions

SSROC stated that EnergyAustralia's proposed 2.5 year cycle should be rejected. It considered that EnergyAustralia's approach to determine a 2.5 year bulk lamp replacement cycle was based on a portfolio of 110 000 – 120 000 obsolete and unreliable florescent luminaires and the use of less reliable mono–phosphor lamps. SSROC stated

[1073] AER, *Supplementary draft decision*, p. 28.

that this portfolio was no longer relevant as the obsolete population has now reduced by some 50 per cent and EnergyAustralia now use more reliable tri–phosphur lamps.[1074]

SSROC encouraged the AER to examine EnergyAustralia's proposed lamp failure rates against the claims of the lamp manufacturers and the AER's results from its decision on energy efficient lighting in Victoria.[1075]

TTEG considered that based on practice in other jurisdictions and accepted Australian Standards, a general 3 year bulk replacement cycle would appear to over service. It considered that a 3.5 year cycle for mercury vapour (MV) lamps and 5 year cycle for high pressure sodium (HPS) lamps should be used to establish a fair and reasonable maintenance charge.[1076]

EnergyAustralia stated that its bulk lamp replacement cycle at 2.5 years had been established following a detailed assessment of asset types and failure rates. It considered that the AER's decision, in the supplementary draft decision to extend EnergyAustralia's bulk lamp replacement cycle from 2.5 years to 3 years provided no technical justification for the change but rather it was based on a high level comparison of bulk lamp replacement cycle period applied in other networks. It submitted that the AER should change its assumption for bulk lamp replacement for EnergyAustralia's network area and if it does not do so it must increase its operating costs to cater for higher operating costs from higher spot lamp replacements.[1077]

EnergyAustralia noted that it introduced its bulk lamp replacement program for the Sydney region in 2006 (the majority of its network) and that one full cycle of bulk lamp replacement had already been completed. It considered that once established, the total operating costs that result from a bulk lamp replacement program of optimal length can be considered as efficient.

AER considerations

There is a direct relationship between the length of a bulk lamp replacement cycle and the number of spot failures that can be expected to occur. In general, the longer the bulk lamp replacement cycle the higher the spot failures that can be expected.

All the NSW DNSPs undertake bulk lamp replacement programs. The public lighting models provided by Country Energy, Integral Energy and EnergyAustralia contain assumptions about the period that bulk lamp replacements are to be conducted and the number of spot failure rates that can be expected. Country Energy's bulk lamp replacement cycle is 3 years for standard lights and 5 years for twin arc lights,[1078] Integral Energy has a 3 year bulk lamp replacement cycle and EnergyAustralia has a 2.5 year cycle.

1074 SSROC, *Additional Submission on supplementary draft decision*, 8 April 2009, pp. 4–5.
1075 SSROC, *Submission on supplementary draft decision,* 27 March 2009, p. 11
1076 TTEG, *Submission on AER Draft Determination 2009-14 Alternative Controls (Public Lighting)*, March 2009, p.15.
1077 EnergyAustralia, *Submission on supplementary draft decision*, 27 March 2009, pp. 12–13.
1078 Country Energy's twin arc lights are located in the Coffs Harbour area.

The AER has obtained and analysed the mortality rates of the most common lamp types in NSW.[1079] Lamp mortality information was provided by Sylvania Lighting Australasia Pty Ltd (Sylvania Lighting) which supplies many of the lighting fixtures used by the NSW DNSPs. The AER has analysed this data conservatively so as to not compromise accepted industry standards.[1080]

A calculation was performed for commonly used lamp types to determine the spot failure rates and the luminous flux rates (a quantitative expression of the brilliance of a source of visible light) of lamps at the end of specific bulk lamp replacement periods. The spot failure and luminous flux rates were determined using an annual lamp operating time of 4 357 hours. The lamps were assessed under 3 and 4 year bulk lamp replacement cycles where the total number of hours under each program were 13 071 and 17 428, respectively. Table 17.3 sets out the results of the AER's assessment.

Table 17.3 indicates that at the end of a three year cycle, spot failure rates vary from as low as 1 per cent per annum for the compact fluorescent and fluorescent lamps up to 9 per cent per annum for the HPS 70W and 100W lamps. Under a 3 year bulk lamp replacement cycle, all lamps retained a luminous flux above 80 per cent. At the end of a 4 year period, spot failure rates for the lamps examined varied from 2 per cent for the fluorescent lamp up to 19 per cent for the tri–phosphor lamps. These findings are consistent with the general principle that as the length of the bulk replacement cycle increases, the number of spot failures increases.

Table 17.3: Spot failure and luminous flux rates of commonly used lamps (%)

	3 year bulk lamp replacement period		4 year bulk lamp replacement period	
Lamp type	**Spot failure p.a**	**Luminous flux**	**Spot failure p.a**	**Luminous flux**
HPS - 70W	9	85	15	84
HPS - 100W	9	85	15	84
HPS - 150W	2	93	5	92
HPS - 250W	2	93	5	92
HPS - 400W	2	93	5	92
HPS - 1000W	8	82	12	71
MV - 50 to 400W	2	81	4	78
Compact fluorescent	1	82	5	80
Tri-phosphor	11	90	19	90
Fluorescent	1	97	2	93

Source: Assumptions for fluorescent lamps sourced from *Evaluation of Low Energy Lights for Minor Road Lighting*, Final report, 12 March 2008, Appendix 2 - Lamp failure rates. All other data sourced from technical data information sheets supplied by Sylvania Lighting.

[1079] Lamp data source: Sylvania Lighting; fluorescent lamp data source: Victorian Sustainable Public Action Group, *Evaluation of Low Energy Lights for Minor Road Lighting*, Final report, 12 March 2008, appendix 2 - Lamp failure rates.

[1080] AS/NZS1158, *Lighting for roads and public spaces*.

The failure rates calculated by the AER from the mortality data support a conclusion that under a 4 year cycle the MV lamps would fall below an 80 per cent luminous flux and the failure rates per annum of the 70W, 100W and 1000W HPS lamps would increase above 10 per cent. However, under a 3 year bulk lamp replacement period these lamps retained a luminous flux of between 81 and 90 per cent and spot failure rates of 2 to 11 per cent.

Based on the above analysis, the AER considers that a 3 year bulk lamp replacement period is appropriate for the MV, tri–phosphor and the 70W, 100W and 1000W HPS lamps because the failure and/or luminous flux rates under a 4 year cycle would compromise the NSW DNSPs ability to meet accepted industry standards.[1081] However, the AER notes that the failure rates and the luminous flux values for the 150W, 250W and 400W HPS, compact fluorescent and fluorescent lamps do not diminish to the same extent as the other lamps under a 4 year bulk replacement cycle. In most instances they do not fall below the rates of the MV and the other HPS lamps under the 3 year bulk lamp replacement cycle. Based on this analysis, the AER considers that these lamps (shaded in table 17.3), should have a 4 year bulk lamp replacement cycle.

EnergyAustralia stated that the AER had not provided technical justification for a change to the period of EnergyAustralia's bulk lamp program. Further, it considered that its cycle of 2.5 years was based on an extensive technical review of lamp failure rates and costs which has been provided as an attachment to its submission.

The AER does not accept that EnergyAustralia has provided sufficient information to support its claims that a bulk lamp replacement cycle of 2.5 years is currently, or expected to be, an efficient bulk lamp replacement cycle. The AER notes that the technical report provided by EnergyAustralia as an attachment to its submission on the supplementary draft decision was completed in January 2004 and is based on information that is now over five years old.[1082] As a consequence, the report does not factor in a number of important changes in EnergyAustralia's public lighting operations.

As a result of EnergyAustralia's concerns, the AER has assessed the mortality curves of common lamps used by the NSW DNSPs. The lamps included in the AER's assessment comprise approximately 67 per cent of EnergyAustralia's total luminaire inventory. The AER's analysis of the technical information indicates that for those lamps commonly installed in EnergyAustralia's luminaires, a bulk lamp cycle of 3 years is appropriate and that for some of these lamps a 4 year cycle may be the optimum cycle.

The AER is also aware from the information provided by EnergyAustralia and submissions from SSROC that it has substantially increased the number of bulk luminaire replacements it has undertaken on its network in the current regulatory control period. This program has resulted in EnergyAustralia replacing less energy efficient and unreliable luminaires with more efficient and reliable luminiares. As a consequence, the AER does not consider that maintenance costs based on a 2.5 year bulk lamp replacement program are efficient, particularly in the next regulatory control period as more modern luminaires and their more reliable lamps are increasingly installed.

[1081] AS/NZS1158, *Lighting for roads and public spaces*.

[1082] EnergyAustralia, *Network maintenance standards, street lighting analysis report*, 9 January 2004.

The AER also notes that a 3 year bulk replacement cycle appears to be the minimum standard applied by other NSW DNSPs and in some cases (for example, lamps on Country Energy's twin arc lights) the bulk lamp replacement cycle is 5 years.

In other jurisdictions, bulk replacement programs are also less frequent than 3 years. For example, a report prepared in 2005 on public lighting for the then Australian Greenhouse Office indicates that DNSPs in Queensland and Western Australia carried out bulk lamp replacement programs consisting of 4 year cycles.[1083] Further the AER's final decision on energy efficient lighting in Victoria applied a 4 year bulk lamp replacement period for energy efficient lamps.[1084] It also noted that the ESCV adopted a 4 year cycle in its 2004 final decision on public lighting charges for all lamps except the 150W and 250W HPS where a 5 year period was applied.[1085] These benchmarks suggest that EnergyAustralia's bulk lamp replacement cycle is not consistent with accepted industry practice.

EnergyAustralia states that if the AER does not agree to maintain its current bulk lamp replacement cycle of years then the AER must increase its operating costs to cater for the higher spot lamp replacements that result. The AER accepts the general principle that a longer bulk lamp replacement program will result in higher lamp failure rates. However, it considers that over the current regulatory control period EnergyAustralia's failure rates would have been falling due to the installation of new, more reliable, luminaires and the use of more reliable lamp technologies in old luminaires. The AER considers that EnergyAustralia's operating costs do not need to be increased as a result of the change in the bulk replacement cycle.

Overall, the AER considers that it is appropriate that EnergyAustralia's maintenance costs be calculated using a 3 year bulk lamp replacement cycle. However, for the compact fluorescent, fluorescent and the 150W, 250W and 400W HPS lamps, the AER considers that a 4 year bulk lamp replacement cycle is appropriate. The AER has come to this conclusion on the basis of its analysis of technical information, submissions from interested parties, the AER's recent public lighting determination in Victoria and the bulk lamp replacement cycles used by other NSW DNSPs and DNSPs other jurisdictions.

Country Energy's bulk lamp replacement cycle is 3 years for standard lights and 5 years for twin arc lights and Integral Energy has a general 3 year bulk lamp replacement cycle. Given the above analysis, the AER has applied a 4 year bulk lamp replacement cycle to Integral Energy's 150W, 250W and 400W HPS, compact fluorescent and fluorescent lamps and a 3 year bulk lamp replacement cycle to the remainder of its lamps. The AER has also applied a 4 year bulk lamp cycle to Country Energy's 150W, 250W and 400W HPS, compact fluorescent and fluorescent lamps and a 5 year bulk lamp replacement period to its twin arc lights.

AER conclusion

In calculating the NSW DNSPs' maintenance charges, the AER has applied a 4 year bulk lamp replacement cycle to the NSW DNSPs' 150W, 250W and 400W HPS, compact

[1083] Kevin Poulton and Associates, Genesis Automation, and Deni Greene Consulting Services for the Australian Greenhouse Office, Department of the Environment and Heritage, *Public Lighting in Australia – Energy Efficiency Challenges and Opportunities*, Final Report, 2005, p. 12.
[1084] AER, *Energy Efficient Public Lighting Charges – Victoria*, Final decision, February 2009, p. 33.
[1085] ESCV, *Review of Public Lighting Excluded Service Charges*, August 2004, p. 20.

fluorescent and fluorescent lamps and a 3 year bulk lamp replacement cycle to all other lamps.

17.5.1.2 Number of bulk lamp replacements made per day

AER supplementary draft decision

In its supplementary draft decision, the AER compared the cost per lamp under a bulk lamp replacement program between the NSW DNSPs and found the costs to be similar for EnergyAustralia and Integral Energy. However, the AER found that the cost per lamp of bulk lamp replacement for Country Energy to be more than double that of EnergyAustralia. From its review of the NSW DNSPs' public lighting models, the AER found that Country Energy took 2.5 times longer to change a lamp under its bulk replacement program than Integral Energy. Country Energy also added a travel time labour cost to the bulk lamp replacement costs increasing its total bulk lamp replacement costs.

In its supplementary draft decision, the AER required Country Energy to reduce the time it takes to replace a lamp under bulk replacement to 8.22 minutes.

Submissions

WSROC stated that it is unclear why labour assumptions for NSW DNSPs should be at much lower levels than the Victoria DNSPs and that if these significantly different labour productivity rates are maintained then the reasons for the discrepancy should be explained.[1086]

TTEG noted that the bulk lamp replacement costs for Integral Energy and EnergyAustralia appeared reasonable but that Country Energy should be required to reduce its charges to a level approaching Integral Energy and EnergyAustralia's rates.

AER considerations

The AER has compared the number of bulk lamp changes made per day by each of the NSW DNSPs and those contained in the AER's final decision on energy efficient lighting in Victoria. Table 17.4 sets out this comparison.

The comparison indicates that Country Energy is significantly less productive when compared to Integral Energy and rural zones in Victoria. However, the AER is also mindful that Country Energy has a unique network and that other rural distributors are unlikely to have the geographical spread of Country Energy's network.

Table 17.4 indicates that Country Energy undertakes 31 bulk lamp replacements per day while Integral Energy undertakes 73 per day. These replacement rates per day also include the time it takes to travel between lamps. EnergyAustralia's model does not indicate how many bulk lamp replacements are undertaken per day as this activity is contracted out to a third party.

[1086] WSROC, *Submission to the AER Draft NSW Distribution Determination (Public Lighting),* March 2009, p.4.

Table 17.4: Comparison of bulk lamp replacement costs and replacements per day

	Country Energy	EnergyAustralia	Integral Energy	Victoria
Number of bulk replacements per day	31	N/A	73	Urban 77[a] Rural 64[a] Remote 51[a] Urban 90[b] Rural 75[b] Remote 60[b]

Source: AER, *Energy Efficient Public Lighting Charges–Victorian Final Decision*, February 2009; and ESCV, *Review of public lighting charges excluded service charges, Final decision*, August 2004.

Note: Number of bulk replacements per day - Country Energy, Pre 1 July 2009 public lighting model; and Integral Energy, Pre 1 July 2009 public lighting model.

(a) Relates to the 2 *14W TF lamp and the 2 * 24W T5 lamp.

(b) Relates to the 80W MV lamp.

The AER's final decision for energy efficient lighting in Victoria contains benchmark bulk lamp replacement rates for the 2 *14W TF and the 2 * 24W T5 lamps. The ESCV's final decision on public lighting excluded services charges provides benchmark bulk lamp replacement rates for the 80W MV. Table 17.4 shows the ranges for the bulk lamp replacement benchmarks varying from 51 to 77 for the energy efficient lamps and 60 to 90 for the 80W MV lamps. The ranges depend upon whether the lamp is located in an urban, rural or remote area.

On the basis of the above comparisons, the AER notes that the bulk replacements per day approved in Victoria are higher than those applied by Integral Energy and significantly higher than Country Energy's. It considers that Country Energy's greater network area does not adequately explain the full discrepancy between it and the Victorian rural networks. The AER considers it is appropriate that the Victorian benchmarks be applied to Country Energy's and Integral Energy's models to calculate their public lighting tariffs. Specifically, the AER will apply the urban benchmarks to Integral Energy and an average of the rural and remote benchmarks to Country Energy.

AER conclusion

The AER has applied the bulk lamp replacement benchmarks approved in Victoria to calculate Country Energy's and Integral Energy's maintenance charges. That is, for energy efficient luminaires the urban benchmark (77) has been applied to Integral Energy and an average of the rural and remote benchmarks (67.5) has been applied to Country Energy. For the 80W MV lamp the AER has applied the urban benchmark (90) to Integral Energy and an average of the rural and remote benchmarks (67.5) to Country Energy. These benchmarks include the time it takes to travel between bulk lamp replacements.

In the absence of benchmark data, the AER has applied a bulk lamp replacement rate of 73 and 62 lamps per day to Integral Energy and Country Energy respectively for other lamp types. These rates are based on Integral Energy's existing assumption of 73 lamps replaced per day with a 15 per cent reduction to recognise the nature of Country Energy's network.[1087]

For the purpose of modelling these assumptions, an average bulk lamp replacement rate of 62.4 for Country Energy and 80 for Integral Energy has been developed and used for all lamps.[1088]

17.5.1.3 Lamp failure rates

A significant component of maintenance costs relate to the assumptions associated with spot maintenance (repair) assumptions. The AER has focused on the two key drivers of spot maintenance costs – the percentage of spot lamp repairs that are required to be undertaken annually and the number of spot lamp replacements that are undertaken per day.

AER supplementary draft decision

The AER did not consider the lamp spot failure rate assumptions of specific lamps in its supplementary draft decision. However, it did consider that EnergyAustralia's approach to calculating the spot replacement costs in its public lighting model was not reasonable and required EnergyAustralia to remodel its maintenance charges based on a reduction in the number of spot replacements of 20 per cent. This was on the basis that the application of a bulk lamp replacement program could reasonably be expected to result in such a reduction.[1089]

Submissions

SSROC considered that EnergyAustralia's spot repair rates have declined and expected them to continue to decline. Based on information provided to it by EnergyAustralia, SSROC considered that EnergyAustralia's actual spot repair rates were significantly higher than its assumed rate of spot repairs used to develop its proposed public lighting prices.[1090]

SSROC noted that the paper *Energy Efficient Luminaires for Local Road Lighting – a Trial* prepared about EnergyAustralia's experience with energy efficient luminaires, found that energy efficient luminaires with electronic ballasts and on long switching cycles were 31 to 38 per cent more reliable than 80W MV luminaires in terms of failure rates. SSROC stated that this finding was similar to the AER's Victorian decision. However, in its supplementary draft decision, the AER did not appear to have accepted this approach.[1091]

TTEG considered that the failure rates claimed by EnergyAustralia were not representative of properly maintained assets.[1092]

[1087] This is based on the percentage differences (15–20 per cent) between the urban and rural rates of bulk lamp replacements made per day as approved by the AER Victoria.

[1088] Average bulk replacement rates have been calculated as follows: Country Energy – rural / remote (64+51+75+60+62)/5=62.4 and Integral Energy – urban (77+90+73)/3=80.

[1089] AER, *Supplementary draft decision*, p. 25–26, 28.

[1090] SSROC, *Submission,* 27 March 2009, p. 8.

[1091] SSROC, *Submission*, 27 March 2009, p. 3.

[1092] TTEG, p. 15.

EnergyAustralia stated that the AER had proposed that spot lamp replacement costs should reduce by 20 per cent as a result of the bulk replacement program being introduced. It stated that for this to be the case, a comparison must be made between the costs of spot lamp replacement with and without bulk lamp replacement.

EnergyAustralia stated that as the costs of bulk replacement are already included in its actual costs and therefore its forecast costs, the comparison is irrelevant. Further it considered that as its public lighting model already includes all non–bulk lamp replacement opex in the spot lamp replacement category, the comparison is not valid unless all other operating costs are removed and all spot replacement operating costs vary as a result of the bulk replacement program. EnergyAustralia believes that its cost allocation methodology is cost reflective and that its spot lamp replacement rate should not be reduced.[1093]

AER considerations

In reviewing the NSW DNSP's spot lamp failure assumptions the AER has considered its earlier conclusions on the appropriate bulk lamp replacement cycle assumptions to be applied to the NSW DNSPs.

The annual spot failure rates applied by the NSW DNSPs in their public lighting models are compared in table 17.5 against the annual spot failure rates calculated by the AER for common lamp types used by the NSW DNSPs. The AER has calculated annual lamp failure rates based on a 3 year bulk lamp replacement cycle and a 4 year bulk lamp replacement cycle. The annual lamp failure rates have been calculated using technical (mortality curve) information. Table 17.5 also sets out the luminaire types to which the lamps relate.

[1093] EnergyAustralia, *Submission on the AER's public lighting supplementary draft decision*, 3 April, p. 15.

Table 17.5: Comparison of per annum spot failure rates (%)

Lamp type	Luminaire type	Country Energy 3 yr BLR (ST) 5 yr BLR (TA)	Energy Australia 2.5 yr BLR	Integral Energy 3 yr BLR	AER 3 yr BLR	AER 4 yr BLR
High pressure sodium - 70W	70 W HPS	3.2/ 2	17	4	9	–
High pressure sodium - 100W	100W HPS	3.2/2	15	4	9	–
High pressure sodium - 150W	150W HPS	3.2/2	15	4	–	5
High pressure sodium - 250W	250W HPS	3.2/1.5	15	4	–	5
High pressure sodium - 400W	400W HPS	3.2/1.5	15	4	–	5
High pressure sodium - 1000W	1000W HPS	3.2	15	4	8	–
Mercury vapour - 50 to 400W	Mercury Vapour	4	6 to 20	4	6	–
Compact fluorescent	42 CFL	4	15	4	–	5
T8 Tri-phosphor	TF 2*20	10	40	4	11	–
T5 Fluorescent	T5	4	22	4	-	2

Source: Country Energy, public lighting model, EnergyAustralia, public lighting model and Integral Energy, public lighting model.

Note: ST means standard light.
TA means twin arc.
BLR means bulk lamp replacement.

The AER's analysis indicates that the lamps associated with the energy efficient luminaires, that is the fluorescent and the compact fluorescent, are relatively reliable lamps, having reasonably low failure rates, even under a four year bulk lamp replacement regime. The 150W, 250W and 400W HPS lamps also appear to be relatively reliable lamps and can reasonably be expected to have a four year cycle. The remaining lamps are less reliable, but under a three year bulk lamp replacement cycle are expected to meet general industry lighting standards.[1094]

The AER has reviewed the annual failure rate assumptions modelled by each of the NSW DNSPs against the outcomes in table 17.5.

The AER considers that the failure rates modelled by Country Energy are reasonable assumptions if the AER's bulk lamp replacement cycle conclusions are applied.

[1094] AS/NZS1158, *Lighting for roads and public spaces*.

The AER notes that Integral Energy has applied a consistent annual lamp failure rate across its lamp stock of 4 per cent. The AER considers this to be reasonable as long as the AER's conclusions regarding bulk lamp replacement cycles are also applied. That is, a four year bulk lamp cycle for the fluorescent, compact fluorescent and the 250W and 400W HPS lamps with all other lamps having a three year bulk lamp replacement cycle.

The AER notes that, even though EnergyAustralia has a shorter bulk lamp replacement cycle than the other NSW DNSPs, its failure rates for the lamps examined are significantly higher than those calculated by the AER and those assumed by Integral Energy and Country Energy. Based on its analysis, the AER has applied the annual failure rates for the lamps contained in table 17.5 to calculate EnergyAustralia's maintenance prices. In respect of the lamp types not shown in the table, the AER considers that a reduction in EnergyAustralia's assumed spot failure rates is appropriate. The rate of spot lamp replacement reduction applied by the AER to these lamps is 20 per cent, consistent with the supplementary draft decision.

With respect to EnergyAustralia's position on the inclusion of its actual costs being incorporated into forecast and also comparisons between spot and bulk, the AER reiterates that one of its principal objectives in the assessment of public lighting was to provide customers a degree of confidence that future charges will be reasonable and that the process in assessing these charges will be both rigorous and transparent.

The AER does not consider that the building block model provided by EnergyAustralia provided the AER with the ability to fully inform customers of the drivers and relationships in costs between different maintenance programs. Specifically, the AER is critical of the EnergyAustralia model's approach of recovering a fixed predetermined level of maintenance costs irrespective of the maintenance program undertaken.

AER conclusion

Overall, from its assessment of the technical data the AER considers that, if the changes to the bulk lamp replacement periods indicated in section 17.5.1.1 are made, then the failure rates assumed by Integral Energy and Country Energy are generally reasonable. However, for the reasons discussed the AER does not consider that the failure rates proposed by EnergyAustralia are reasonable. In calculating EnergyAustralia's maintenance charges the AER has applied the lamp failure rates contained in table 17.5 in conjunction with the bulk lamp replacement cycles in section 17.5.1.1. For those lamp types not included in table 17.5, the AER has reduced EnergyAustralia's spot failure rates by 20 per cent.

17.5.1.4 Spot lamp replacements per day

Submissions

WSROC stated that it is unclear why labour assumptions for NSW DNSPs are out of line with the Victoria DNSPs and that if these significantly different labour productivity rates are maintained then the reasons for the discrepancy should be explained.[1095]

[1095] WSROC, *Submission to the AER Draft NSW Distribution Determination (Public Lighting),* p. 4.

AER considerations

The AER has compared the spot lamp replacements applied by the NSW DNSPs to other spot replacement benchmarks in other jurisdictions. The spot lamp replacements per day applied by the NSW DNSPs in their models are compared in table 17.6 to those approved by the AER in its recent final decision on energy efficient lighting in Victoria and in the ESCV's 2004 determination on public lighting charges.

Table 17.6: Comparison of the number of spot lamp replacements made per day

	Country Energy	EnergyAustralia	Integral	Victoria
Number of spot lamp replacements per day (8.33 hour day)	18.94	Traffic route: 8.33 Streetlight: 12.50	18.75	26 urban[a] 21 rural[a] 17 remote[a] 30 urban[b] 25 rural[b] 20 remote[b] 20 urban[c] 16 rural[c] 12 remote[c]

Source: Country Energy, public lighting model; EnergyAustralia, public lighting model; Integral Energy public lighting model; and AER, *Final decision, Energy efficient public lighting charges – Victoria*, January 2009.

(a) Spot repair rate for energy efficient lighting, relates to the 2*14W and 2*24W T5 lamps. Source: AER, *Energy efficient public lighting charges – Victoria.*

(b) Relates to 80W Mercury Vapour lamps. Source: ESCV, *Review of public lighting charges excluded service charges,* August 2004.

(c) Relates to 150W and 250W HPS lamps. Source: ESCV, *Review of public lighting charges excluded service charges,* August 2004.

Country Energy and Integral Energy both assume around 19 spot replacements per day and EnergyAustralia assumes 8 spot replacements per day for traffic routes and 13 spot replacements per day for street lights.

The rates approved in the AER's Victorian final decision for energy efficient lights (that is, the 2 * 14W and 2 *24W T5 lights) vary between 17 and 26 spot replacements per day depending on the area of the network where the replacements are being undertaken. The replacement rates approved in the ESCV's 2004 final decision for the 80W Mercury Vapour lamp range from 20 to 30 spot replacements per day depending on the area of the network involved, while the daily spot replacement rate for the 150W and 250W HPS lamps ranged from 12 to 20.

While recognising the differences in Country Energy's network as opposed to the rural Victorian DNSPs, the AER considers that it is reasonable to require Country Energy to achieve the ESCV and the AER's rural benchmarks for daily spot lamp replacements for the lamps contained in table 17.6. The AER considers that while some areas of Country Energy's network are remote in nature, others are more rural in nature and therefore it is reasonable that an average of both a rural and a remote benchmark be applied.

In relation to Integral Energy and EnergyAustralia, the AER considers that it is reasonable to require them to achieve the ESCV's and the AER's urban benchmarks for daily spot lamp replacements for the lamps contained in table 17.6.

AER conclusion

The AER considers that the NSW DNSPs maintenance charges should be calculated by applying the relevant Victorian spot replacements per day benchmarks for the lamps set out in table 17.6. For the purpose of modelling these assumptions, a simplified approach has adopted, using an average spot lamp replacement rate of 18.5 for Country Energy and 25.33 for EnergyAustralia and Integral Energy, to be applied across all lamp types.[1096]

17.5.1.5 Pricing of energy efficient lighting

Submissions

SSROC stated that EnergyAustralia's proposed pricing for energy efficient lighting is a major concern. It considered that there were large and unexplained differences between the proposed costs for these lights and other lighting types between EnergyAustralia and other utilities. It stated that the ESCV's draft decision on energy efficient lighting provided an important benchmark for NSW public lighting pricing. In particular, it noted that the recommended maintenance charges for these new lighting types in the ESCV's draft decision were broadly half the amount proposed by EnergyAustralia.[1097]

Campbelltown City Council requested that consideration be given to ensuring that energy efficient lighting was not priced out as a viable option to replacing less efficient luminaire types. It considered that the price differential between energy efficient lighting and the less efficient equivalent created a disincentive for the uptake of more efficient lamps.[1098]

WSROC requested that the pricing of the T5 and the CFL lights be reviewed and the prices in the final determination reduced to correspond with pricing in Victoria. It noted that if pricing parity could not be achieved for energy efficient lighting then WSROC sought information justifying this discrepancy. WSROC stated that inappropriately high pricing is a disincentive to the adoption of energy efficient lighting and the achievement energy efficiency and greenhouse abatement policy priorities.[1099]

AER considerations

The AER recognises the concerns raised by stakeholders regarding the prices of energy efficient lighting opposed to other lighting types. The AER's principal concern is that prices should be cost reflective and each individual lighting type assessed on its merits. Where a lighting type requires less maintenance, then the AER considers that the charge for that asset should reflect this, irrespective of whether it is an energy efficient luminaire or not.

The AER has compared the maintenance tariffs for the 80W MV and the energy efficient luminaires approved in its January 2009 Victorian decision with those approved in this final decision for the NSW DNSPs (tariff class 4). Table 17.7 shows this comparison.

1096 Average spot lamp replacement rates have been calculated as follows: Country Energy – rural / remote (21+17+25+20+16+12)/6=18.5, EnergyAustralia and Integral Energy – urban (26+30+20)/3=25.33.

1097 SSROC, *Submission on the AER's Draft Distribution Determination 2009-2014 and EnergyAustralia's Revised Regulatory Proposal*, p. 7.

1098 Campbelltown City Council, *Submission on AER supplementary draft decision on public lighting*, 27 March 2009.

1099 WSROC, *Submission to the AER Draft NSW Distribution Determination (Public Lighting),* p. 6–8.

Table 17.7: AER approved maintenance tariffs in Victoria and NSW ($)

	80W MV	2*14W T5	2*24W T5
Country Energy	29.84	33.96	40.88
EnergyAustralia	39.40	37.62	–
Integral Energy	33.00	39.07	40.64
Jemena	15.92	19.22	–
CitiPower	17.28	20.67	–
Powercor	16.33	20.09	–
SP AusNet (nth/east)	16.87	20.74	23.50
SP AusNet (central)	15.15	18.37	21.05
United Energy Distribution	15.22	18.55	–

Source: AER, *Final decision, Energy efficient public lighting charges – Victoria*, January 2009 and AER, *Final decision, NSW distribution determination*, April 2009.

Note: Integral Energy's tariffs have been reduced by the tax recovery component on gifted assets. A tariff comparison of 42W CFL public lighting was not included because a tariff for this light type was not approved in the AER's Victorian decision.

The differences in the maintenance tariffs between the two jurisdictions result principally from variations in assumed labour rates and overheads. These variations occur for a number of reasons as discussed in this chapter, however, the AER stresses that it considers that the NSW tariffs represent cost reflectivity given the specific market and operating conditions prevalent in NSW.

The AER has also examined the differences in the capital charges for these luminaires types with the charges of the Victorian DNSPs. The tariffs presented in table 17.8 are representative of both capital and maintenance costs, that is, the AER's tariff 3.

Table 17.8: Comparison of AER approved tariffs in Victoria and NSW – capital and maintenance components ($)

	80W MV	2*14W T5	2*24W T5
Country Energy	86.13	108.41	119.87
EnergyAustralia	68.63	82.50	–
Integral Energy	67.42	85.75	88.24
Jemena	27.85	23.10	–
CitiPower	38.10	26.50	–
Powercor	31.17	25.21	–
SP AusNet (nth/east)	30.76	27.71	30.47
SP AusNet (central)	28.33	25.26	27.94
United Energy Distribution	31.95	23.38	–

Source: AER, Final decision models—energy efficient public lighting charges, February 2009 and AER, *Final decision, NSW distribution determination*, April 2009.

Note: A tariff comparison of 42W CFL public lighting was not included because a tariff for this light type was not approved in the AER Victorian decision.

When comparing the tariffs from the Victorian decision with the NSW tariffs, it is necessary to recognise that they do not represent a like for like comparison.

While the actual uninstalled cost per luminaire proposed by the NSW DNSPs is broadly consistent with those contained in its Victoria decision, the charges for the luminaires in Victoria do not include a construction component, which broadly accounts for 50 per cent of the total cost of a constructed luminaire, do not reflect a full depreciation charge and have been established using a different discount rate (WACC) to that applied in NSW.

Interested parties also raised the issue that the prices the AER had established for energy efficient luminaires for the NSW DNSPs had created a disincentive for customers to install new energy efficient luminaires. As stated previously, the AER's objective has been to set cost reflective prices for the assets contained within the NSW DNSPs' asset bases.

In terms of the maintenance component, the AER has assessed the relative costs of each type of luminaire type. For energy efficient luminaires, the AER concluded that they were more cost effective to maintain than non-energy efficient luminaires. This is reflected in the AER's decision to calculate the prices for energy efficient luminaires using a bulk lamp replacement cycle of 4 years rather than 3 years.

In terms of the capital component, in some instances the cost of purchasing an energy efficient luminaire is greater than a non-energy efficient luminaire. These are market prices and beyond the control of both the AER and the DNSPs. On the basis that costs should be cost reflective, the AER does not consider that it is appropriate to impose additional costs over those provided by a competitive market (that is, the supply of luminaires) to create behavioural incentives in the DNSPs customers. However, notwithstanding the AER's position on establishing cost reflective tariffs, there would be nothing to prevent a DNSP offering incentives either through lower tariffs or other means for customers to take up energy efficient lumianires.

The AER also notes that the prices that it has established for energy efficient luminaires have been reduced compared with those contained in its supplementary draft decision. While the total (capital and maintenance) prices for energy efficient luminaires may still be above that of other types of luminaires, the AER notes that when maintenance costs, energy savings and greenhouse gas reductions are taken into consideration, these luminiares may still represent an economic choice for customers.

AER conclusion

The AER has examined the differences in tariffs between its final Victorian decision on energy efficient lights and its final decision for the NSW DNSPs. The AER acknowledges that the tariffs that it has established for the NSW DNSPs, while reduced from its supplementary draft decision, remain higher than those approved by it for the Victorian DNSPs for energy efficient lights. However, care needs to be taken in comparing the charges between NSW and Victoria and adjustments need to be made in order to obtain a like for like comparison. Where differences between the Victoria and NSW public lighting tariffs remain, the AER considers that these result from the different inputs and assumptions but that these have been reviewed by the AER in the context of the NSW DNSPs' operating environment and found to be reasonable.

17.6 Assets constructed before 1 July 2009

17.6.1 AER draft decision

In the draft decision, the AER required the NSW DNSPs to develop a proposed schedule of charges for public lighting assets constructed before 1 July 2009 by applying a limited building block approach that would establish:[1100]

- an annual capital charge for each individual customer
- an annual maintenance charge for each individual customer
- a total annual charge for each individual customer.

The AER also required the NSW DNSPs to determine their public lighting RAB by using IPART's 2004 opening RAB plus actual capex in the current regulatory control period less an allowance for depreciation.[1101]

The asset base was required to be allocated to individual customers thereby allowing charges to reflect the age of the customer's public lighting assets.[1102]

The AER required the NSW DNSPs to calculate an annual maintenance charge for each asset based on efficient labour and materials costs assuming a 3 year bulk lamp replacement cycle with a provision for spot lamp replacements. The AER considered that the same maintenance charges would apply to both new and existing assets.[1103]

[1100] AER, *Draft decision*, pp. 339–340.
[1101] AER, *Draft decision*, pp. 329–330.
[1102] AER, *Draft decision*, p. 339.
[1103] AER, *Draft decision*, pp. 338–339.

17.6.2 Revised regulatory proposals

Country Energy

Country Energy proposed a public lighting RAB of $16 million as at 30 June 2009.[1104]

To derive its capital charge, Country Energy applied a pre–tax real weighted average cost of capital (WACC) of 8.11 per cent to its asset base and applied a half life assumption to calculate the depreciation on public lighting assets constructed before 1 July 2009. The half life assumption was proposed by Country Energy because it could not identify age related information for every public lighting asset in service.[1105]

Country Energy calculated annual maintenance charges for every asset type using a 3 year bulk lamp replacement program for standard lights and a 5 year bulk lamp replacement program for twin arc lights.[1106]

On the basis that a significant amount of public lighting costs are driven by labour costs, Country Energy proposed to index its 2009–10 prices each year by the annual real increase in the NSW EGW wages.[1107]

EnergyAustralia

Following a request from the AER, EnergyAustralia provided a public lighting RAB value of $111 million as at 30 June 2009.[1108] EnergyAustralia noted that this information did not form part of its revised regulatory proposal.

To derive a capital charge, EnergyAustralia applied a nominal vanilla WACC of 9.72 per cent and calculated depreciation by applying actual asset lives for all assets constructed after 1 July 2004 and a half life assumption for assets constructed before 1 July 2004.[1109]

EnergyAustralia's inventory database is maintained using replacement cost values. To determine an allocation of the rolled forward RAB to each customer, EnergyAustralia derived each individual customer's percentage of the total inventory database at replacement cost. It then applied these percentages to the 1 July 2009 written down RAB to obtain an individual customer's allocation of the RAB.[1110]

In addition, EnergyAustralia's database only contained the date the original asset was installed, rather than specific individual asset age information. To derive the remaining lives of its public lighting assets, assets that had installation dates that were more than 20 years old had multiples of 20 years subtracted from the installation date until the age was less than 20 years. EnergyAustralia used the residual age as an estimate of the asset's current age.[1111]

[1104] Country Energy, *Revised regulatory proposal*, p. 82.
[1105] Country Energy, *Revised regulatory proposal*, p. 82.
[1106] Both these programs include a spot within bulk component.
[1107] Country Energy, *Revised regulatory proposal*, p. 81.
[1108] EnergyAustralia, *Revised regulatory proposal*, p. 174.
[1109] EnergyAustralia, Annuity model.
[1110] EnergyAustralia, Annuity model.
[1111] EnergyAustralia, *Revised regulatory proposal*, p. 175.

EnergyAustralia calculated annual maintenance charges for every asset type using a 2.5 year bulk lamp replacement program.[1112]

In terms of escalating future tariffs, EnergyAustralia proposed escalating its maintenance costs by the EGW NSW wages escalation rate and the capital charge by CPI.[1113]

Integral Energy

Integral Energy proposed a public lighting RAB of $38 million as at 30 June 2009.[1114]

To derive its capital charge, Integral Energy applied a nominal vanilla WACC of 10.02 per cent and a half life assumption to calculate depreciation on public lighting assets prior to 1 July 2004 and a 20 year remaining life for all new public lighting assets installed after 1 July 2004 on a straight line basis.[1115]

Integral Energy's inventory database is maintained using written down values according to estimated remaining lives. To derive an allocation of the RAB to each customer, Integral Energy derived each individual customer's percentage of the total inventory database at its written down value and then applied these percentages to the RAB to obtain an individual customer's allocation of the RAB.[1116]

Integral Energy's maintenance charge is based on a 3 year spot within bulk lamp replacement program.[1117]

Integral Energy proposed CPI as the escalation rate to apply to future prices.[1118]

17.6.3 AER supplementary draft decision

The AER concluded that the public lighting opening RABs proposed by Country Energy and Integral Energy were reasonable estimates and that the approaches used to calculate remaining lives and depreciation were also reasonable.[1119]

The AER also considered that the public lighting RAB submitted by EnergyAustralia also represented a reasonable estimate.[1120]

The AER was of the view that the approach taken by Country Energy and Integral Energy to allocate their 2009 closing RABs using a ratio of an individual customer's written down asset valuation to the total written down value was reasonable given the data limitations that existed.[1121] With respect to EnergyAustralia, the AER decided that the RAB should be allocated based on a ratio of a customer's written down assets rather than the replacement value as provided by EnergyAustralia.[1122]

[1112] EnergyAustralia, *Revised regulatory proposal*, p. 190.
[1113] EnergyAustralia, *Revised regulatory proposal*, p. 173 and EnergyAustralia, Annuity model.
[1114] Integral Energy, *Revised regulatory proposal*, p. 94.
[1115] Integral Energy, *Revised regulatory proposal*, pp. 95–96.
[1116] Integral Energy, *Revised regulatory proposal*, pp. 94–96.
[1117] Integral Energy, *Revised regulatory proposal*, pp. 94–96.
[1118] Integral Energy, *Revised regulatory proposal*, pp. 94–96.
[1119] AER, *Supplementary draft decision*, p. 16.
[1120] AER, *Supplementary draft decision*, p. 16.
[1121] AER, *Supplementary draft decision*, p. 18.
[1122] AER, *Supplementary draft decision*, p. 18.

The AER maintained its view that a 3 year bulk lamp replacement cycle was appropriate. As a result, the AER required EnergyAustralia to remodel its maintenance prices based on a 3 year bulk replacement lamp cycle. In addition, the AER requested EnergyAustralia to remodel its maintenance prices incorporating a spot replacement improvement rate of 20 per cent.[1123]

The AER considered that Country Energy had the capacity to significantly improve the time it modelled to undertake a bulk lamp replacement. It therefore required Country Energy to remodel its annual maintenance prices using the assumption that under a bulk lamp replacement regime a replacement time per lamp of 8.22 minutes rather than every 16.8 minutes.[1124]

The AER accepted the overhead rates proposed by EnergyAustralia and Integral Energy.[1125] However, the AER considered that Country Energy's plant overhead rate and materials overhead rate were not reasonable and required these each to be reduced to 25 per cent.[1126]

The AER considered that the approach used by EnergyAustralia and Integral Energy to inflate their price paths was reasonable, while Country Energy was required to remove a double counting that existed in the escalation of its capital charge.[1127]

The AER requested the NSW DNSPs to recalculate their 2009–10 tariffs and price paths for assets constructed prior to 1 July 2009 based on the inputs and assumptions contained in table 17.9.

[1123] AER, *Supplementary draft decision*, pp. 25–26.
[1124] AER, *Supplementary draft decision*, pp. 26–27.
[1125] AER, *Supplementary draft decision*, p. 29.
[1126] AER, *Supplementary draft decision*, pp. 28, 44.
[1127] AER, *Supplementary draft decision*, p. 31.

Table 17.9: AER supplementary draft decision key inputs and assumptions

	Country Energy	EnergyAustralia	Integral Energy
Nominal vanilla WACC	9.72 %	9.72 %	9.72 %
Pre–tax real WACC	7.65 %	7.69	7.71
Bulk lamp replacement rate	3 years	3 years	3 years
Time taken to replace a lamp under a bulk lamp replacement	8.22 minutes	–	6.85 minutes
Spot lamp failure rate	–	Amended to reflect spot failure rates under a bulk replacement program	–
Percentage of real labour escalation rate applied to maintenance charge	60 %	60 %	60 %
NSW EGW real labour growth rate	3.9 %	3.9 %	3.9 %
Forecast inflation	3 %	3 %	3 %
Materials overhead	25 %	20 %	–
Plant overhead	25 %	–	–

Source: AER, *Supplementary draft decision*, p. 32.

17.6.4 Issues and considerations

17.6.4.1 AER's use of a building block approach for pre 1 July 2009 assets

AER statement of approach

Clause 6.2.5(e) of the transitional chapter 6 rules provides:

> The AER must, before 1 March 2008 or the date that is one month after the commencement date (whichever is the later), publish a statement indicating its likely approach to the control mechanisms for alternative control services. In preparing the statement, the AER may carry out such consultation as the AER thinks appropriate and may take into consideration any consultation carried out before the commencement date.

In its February 2008 statement indicating the likely approach to the control mechanism for alternative control services (statement on alternative control services), the AER proposed to apply the following form of control to public lighting services over the next regulatory control period:[1128]

- a schedule of fixed prices in the first year of the regulatory control period
- a price path (such as CPI–X) for the remaining years of the regulatory control period.

The AER proposed to determine the initial price levels and the price path with reference to the efficient costs of providing public lighting services. The statement on alternative control services indicated that a limited building block analysis would be employed to determine efficient prices.[1129]

The AER is able to make amendments to its likely approach to the control mechanism for alternative control services in the distribution determination. However, if the AER does make any amendments to the control mechanism for alternative control services it is required to provide its reasons for doing so.[1130]

AER draft decision

The draft decision modified the approach set out in the statement on alternative control services. Under the modified approach, the AER requested each NSW DNSP to develop two schedules of fixed prices for the first year of the next regulatory control period and a price path for the remaining years of the next regulatory control period. The first schedule of prices related to public lighting assets constructed before 1 July 2009 and was to be developed using a limited building block method. This approach is consistent with the statement on alternative control services. The second schedule of prices related to public lighting assets constructed after 30 June 2009 and was to be developed using an annuity capital charge method.[1131] The adoption of an annuity model for assets constructed after 30 June 2009 is a modification of the statement on alternative control services. The AER's reasons for making this modification are set out in sections 17.6.5 and 17.6.11 of the draft decision.

AER supplementary draft decision

The supplementary draft decision confirmed the draft decision that the NSW DNSPs were to use a limited building block approach for assets constructed before 1 July 2009 and an annuity method for assets constructed after 30 June 2009.[1132] The supplementary draft decision set out the draft decision on the schedules of prices and price paths proposed by the NSW DNSPs.

Submissions

EnergyAustralia stated that the use of a building block model has brought with it unnecessary complexity and created additional problems that cannot be solved without detailed asset and age related information, which the AER is aware does not exist. EnergyAustralia stated that the AER's approach unnecessarily requires it to develop a different price list based on a different methodology for the same service.

[1128] AER, *Statement on control mechanism for alternative control services for the ACT and NSW 2009 distribution determinations*, February 2008, pp. 4–5.

[1129] AER, *Statement on control mechanism for alternative control services*, February 2008, pp. 4–5.

[1130] AER, *Statement on control mechanism for alternative control services*, February 2008, p. 7; and NER, transitional chapter 6 rules, clause 6.2.8(c).

[1131] AER, *Draft decision*, sections 17.6.11 and 17.8.

[1132] AER, *Supplementary draft decision*, pp. 12, 34.

EnergyAustralia submitted that the AER has not had sufficient regard to the factors listed in clause 6.2.5(d) of the transitional chapter 6 rules.[1133]

EnergyAustralia considered that the AER based its rejection of its annuity model methodology for assets constructed before 1 July 2009 on the fact that it objected to an input used in the methodology (that is, the use of replacement cost for assets instead of depreciated historical costs) rather than an objection to the methodology itself, which the AER accepts for assets constructed after 30 June 2009. EnergyAustralia submitted that if the AER refuses to approve a methodology, value or amount, the substitute must be determined on the basis of the current regulatory proposal and amended from that basis only to the extent necessary to enable it to be approved in accordance with the rules (clauses 6.12.1 and 6.12.3 of the transitional chapter 6 rules). EnergyAustralia submitted that the AER had exceeded its permitted discretion by rejecting the model rather than addressing the input in the model.[1134]

EnergyAustralia also considered that its annuity method was more consistent with the national electricity objective than the RAB roll-forward approach proposed by the AER.[1135]

SSROC stated that the application of an annuity basis was correctly rejected by the AER in the draft decision and supplementary draft decision. It considered that such an approach would create significant distortions and a windfall gain for EnergyAustralia.[1136] SSROC stated that:[1137]

- there is no precedent for the application of an annuity approach to existing assets
- EnergyAustralia's previous proposal was rejected by IPART
- the model previously provided to IPART treated existing assets as if they were new, significantly overstating the capital costs
- IPART's consultants in the 2004 review cautioned against several aspects of the annuity approach (including changing depreciation methodologies part way through).

SSROC noted that EnergyAustralia asserts that customers are purchasing a lighting service rather than paying for a particular set of assets and that the cost of this service is not related to the age of the asset providing the service. SSROC stated that councils strongly reject the implicit EnergyAustralia claim that there is equivalency of service between different lighting types and ages of assets. It noted that charges have not historically been based on providing a particular standard of lighting service nor has EnergyAustralia claimed that it delivers a particular standard of service.[1138]

SSROC stated that it would be entirely inappropriate to now switch to an untested annuity pricing methodology on the basis of an assumed equivalence in service levels between historical and new assets that is not reflective of the service levels being delivered. It

1133 EnergyAustralia, *Submission on the supplementary draft decision*, 3 April 2009, p. 8.
1134 EnergyAustralia, *Submission on the supplementary draft decision*, 3 April 2009, p. 8.
1135 EnergyAustralia, *Submission on the supplementary draft decision*, 3 April 2009, p. 10.
1136 SSROC, *Supplementary submission*, 8 April 2009, pp. 1–3.
1137 SSROC, *Supplementary submission*, 8 April 2009, pp. 1–3.
1138 SSROC, *Supplementary submission*, 8 April 2009, pp. 2–3.

considered that this is particularly the case for EnergyAustralia with a considerably larger legacy of obsolete public lighting assets than other DNSPs.[1139]

TTEG stated that, in the absence of competition, adopting a building block approach to analysis is reasonable.[1140]

AER considerations

Consideration of factors listed in clause 6.2.5(d)

In its statement on alternative control services, the AER stated that it had considered the issues it was required to have regard to under clause 6.2.5(d) of the transitional chapter 6 rules in determining an appropriate form of regulation (that is, which of the control mechanisms set out in clause 6.2.5(c2) of the transitional chapter 6 rules is likely to apply).[1141]

The AER's consideration of the factors set out in clause 6.2.5(d) of the transitional chapter 6 rules is contained in section 7 of the final decision which accompanied the statement on alternative control services (final decision on alternative control services).[1142] In the draft decision, the AER noted that it had regard to the factors set out in clause 6.2.5(d) and that the AER had not changed its position from that set out in the final decision on alternative control services. The AER considered that a schedule of fixed prices and price path continued to be the appropriate form of control for the reasons set out in the final decision on alternative control services.[1143]

In light of EnergyAustralia's submissions, the AER has had further regard to the factors in clause 6.2.5(d) of the transitional chapter 6 rules. It notes that the NER does not set out any specific factors the AER should have regard to when assessing and deciding on the methodology on which the control mechanism is to be based (for example, a building block or annuity model). In the circumstances, however, the AER considers that it is appropriate to be guided by and apply its assessment of the appropriate methodology against the factors set out in clause 6.2.5(d).[1144] The AER's consideration of these factors is set out below.

Potential for the development of competition and how the capital charge methodology might influence that potential

EnergyAustralia considered that the use of depreciated costs and an asset roll forward approach ensures that the costs of public lighting services provided by existing assets will always be lower than the costs of services provided by new assets and therefore customers have an incentive to stay with the current service provider. However, it states that if prices were set using replacement costs, the costs to the customer of choosing

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1139 SSROC, *Supplementary submission*, 8 April 2009, pp. 1–3.

1140 TTEG, *Submission on AER Draft Determination 2009-14 Alternative Controls (Public Lighting)* March 2009, p.7.

1141 AER, *Statement on control mechanism for alternative control services*, February 2008, p. 4.

1142 AER, *Final decision, Control mechanisms for alternative control services for the ACT and NSW 2009 distribution determinations*, February 2008, pp. 18–19.

1143 AER, *Draft decision*, p. 338.

1144 The appropriateness of using the criteria in clause 6.2.5(d) as a guide is supported, in particular, by clause 6.2.5(d)(5) which allows for consideration of 'any other factor'.

another lighting provider would be equivalent and is therefore more likely to encourage wider competition in the market for public lighting services.[1145]

Under the price cap control mechanism, the objective is to cap prices at efficient levels and if other providers are able to provide the service more efficiently then a customer is able to choose that provider. Both an annuity approach and the building block approach can be used to establish efficient prices.

In relation to existing assets, it is noted that the assets have already been constructed (that is, the service has already been provided), however, the provision of maintenance on these existing assets can potentially be delivered by other providers. The AER notes that maintenance costs under its regime are the same under either the building block approach or the annuity approach and therefore competitive outcomes should be the same under either approach. The AER also notes that for the construction of new assets, where both competition in construction and maintenance is possible, an annuity approach based on replacement costs is required by the AER and, consistent with EnergyAustralia's comments, should encourage competitive outcomes for these assets.

Possible effects of the capital charge methodology on the administrative costs to the AER, the DNSP and users or potential users

EnergyAustralia argued that the AER's building block approach will result in higher administrative costs. In particular, it considers that the need for two price lists, the need for detailed asset age information and the case by case assessment of what it refers to as the retrofit tariff will increase its, the AER's and customers administrative costs.

The AER notes that Country Energy, Integral Energy and other interested parties did not raise any concerns about the administrative impact of the methodology proposed by the AER. Nevertheless, the AER agrees that the upfront costs for the building block approach will be slightly higher for all parties than an annuity approach based on replacement costs. However, the AER considers that these costs are more than offset by the benefits to customers from paying depreciated historical costs rather than replacement costs for their existing assets.

The regulatory arrangements (if any) applicable to the relevant service immediately before the commencement of the distribution determination

IPART has used a building block approach to assess and approve applications for price increases from the NSW DNSPs during the current regulatory control period. The AER is also aware that EnergyAustralia previously proposed prices based on an annuity approach but that this approach was rejected by IPART. The AER's annuity approach will only apply to new assets, that is, assets constructed after 30 June 2009.

The desirability of consistency between regulatory arrangements for similar services (both within and beyond the relevant jurisdiction)

The AER is a national regulator operating under a national regime. The different regulatory regimes which existed in the various states and territories constituted a substantial impediment to the development of a national energy market and resulted in significant costs being imposed on industry participants (with those costs typically being

[1145] EnergyAustralia, *Submission on the AER's public lighting supplementary draft decision*, 3 April 2009, pp. 17–18.

passed on to end users).[1146] One of the reasons for the establishment of the national regime was to minimise the complexities for DNSPs associated with dealing with more than one regulator and differing interpretations of the rules.[1147]

Similar reasoning can be applied to the customers of the DNSPs. The adoption of consistent methodologies by all NSW DNSPs assists public lighting customers to more effectively comment on NSW DNSPs' regulatory proposals. For example, the AER is aware one NSW regional organisation of councils has members that operate in two of the NSW DNSPs' network areas. The AER considers it is important under the national regime to maintain a consistent approach wherever possible across all NSW DNSPs and has determined that it is appropriate that the same methodology be used by all NSW DNSPs to calculate charges for public lighting assets constructed before 1 July 2009.

The AER also considers that a building block approach to calculate the public lighting charges for existing assets may also be appropriate in other jurisdictions where similar circumstances to that in NSW exist.

Other relevant factors

The AER considers that when a change in the asset valuation approach and/or price setting methodology occurs part way through the life of a regulated asset, and the age and value of the assets are not treated consistently, then a consequence can be excess or deficient returns, or the assessment of such returns could be obscured.

In the case of EnergyAustralia, the public lighting charges set by IPART in the current regulatory control period have been established from an asset base that was assumed to be half way through its useful life.[1148] In its regulatory proposal, EnergyAustralia calculates its charges based on an annuity approach that relies on replacement costs.[1149] The AER is concerned that in changing from a building block method to a replacement cost annuity method customers will pay charges beyond what is efficient on EnergyAustralia's existing stock of assets.

Under a building block method with depreciation calculated on a straight line basis allowable revenues will be greater at the outset of the asset's life and will diminish as the asset ages. In other words, charges are at their highest for the first half of an asset's life under a building block approach.

With respect to EnergyAustralia's current charges and proposed asset lives, the AER considers that customers should be entitled to receive lower capital charges in recognition that they have already paid higher charges in the past. Such an approach does not prevent EnergyAustralia from recovering the efficient costs of new public lighting assets installed after 30 June 2009 (as these are captured under the AER's tariff 3) or restrict its ability to recover the efficient cost of maintaining these assets.

Maintaining a building block approach for assets constructed before 1 July 2009 draws a 'line in the sand', allowing the NSW DNSPs to achieve a normal return on, and of, capital over the life of their existing public lighting assets while at the same time allowing

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1146 MCE, *National Framework for electricity and gas distribution and retail regulation*, Foreword and issues paper, August 2004, p. 12 of issues paper prepared by Allens Arthur Robinson.
1147 MCE, p. 12 of issues paper prepared by Allens Arthur Robinson.
1148 EnergyAustralia, *Revised regulatory proposal*, p. 174.
1149 EnergyAustralia, *Revised regulatory proposal*, p. 177.

customers to receive reduced prices to reflect the fact that they have already paid higher costs. In short, it is not appropriate to change to an annuity method part way through an assets life and not preserve age and value assumptions as this can result in windfall gains and losses for DNSPs and customers, primarily from differences in the profile of depreciation under the two approaches. Fundamentally, this is why the AER requires different approaches to the calculation of capital charges for new and existing assets.

The AER notes that neither Country Energy, Integral Energy, or other interested parties, raised concerns with the AER's decision to require the use of a building block approach for public lighting assets constructed before 1 July 2009.

In preparing the statement on alternative control services, the AER followed the procedure set out in clause 6.2.5(e) of the transitional chapter 6 rules. As part of the consultation undertaken by the AER, it sought submissions on using a building block approach for determining the prices for alternative control services.[1150] The AER received a number of submissions including submissions from EnergyAustralia. EnergyAustralia submitted that it had no fundamental concerns with a building block approach.[1151] EnergyAustralia noted it is 'likely that IPART would have used a building block assessment to ensure prices signal the economic cost of service provision (required under the Excluded Services Rule)'.[1152] EnergyAustralia also stated that it supported:

> the AER in maintaining a consistent approach to the regulation of Alternative Control Services, principally public lighting, by setting a price cap for this service. A building block assessment will be the most appropriate way to determine the cost of this service, with a roll forward estimate of the asset value. The AER must recognise the linkages between: the cost of service; the prices paid; and the service levels provided, in making its public lighting determination.[1153]

The AER notes that neither of EnergyAustralia's submissions canvassed the adoption of an annuity approach.

Based on its analysis of the factors in clause 6.2.5(d) of the transitional chapter 6 rules the AER considers that a building block approach should be used to calculate public lighting charges for assets constructed before 1 July 2009.

Consistency with the national electricity objective

The national electricity objective, as stated in the NEL is to promote efficient investment in, and efficient operation and use of, electricity services for the long-term interests of consumers of electricity with respect to:[1154]

- price, quality, safety, reliability, and security of supply of electricity
- the reliability, safety and security of the national electricity system.

[1150] AER, *Issues paper, Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–2014, Demand management incentive scheme, Control mechanisms for alternative control services, Approach to determining materiality for possible pass through events*, November 2007; and AER, *Preliminary positions, Matters relevant to distribution determinations for ACT and NSW DNSPs for 2009–2014, Demand management incentive scheme, Control mechanisms for alternative control services, Approach to determining materiality for possible pass through events*, December 2007.

[1151] EnergyAustralia, *Submission on the AER issues paper*, December 2007, p. 9.

[1152] EnergyAustralia, *Submission on the AER issues paper*, pp. 9–10.

[1153] EnergyAustralia, letter to the AER, 29 January 2008, p. 1.

[1154] NEL, Part 1, section 7.

The AER does not consider that its building block approach departs from these objectives. The approach does not inhibit a NSW DNSP's ability to set prices to achieve at least an efficient rate of return on, and of, capital over the life of their public lighting assets, it promotes efficient investment in and use of public lighting services and does not constrain the DNSPs from providing a secure, safe and reliable service.

AER's exercise of its discretion

The AER is of the view that it has correctly exercised its discretion in requiring EnergyAustralia to use a limited building block model to calculate a schedule of fixed prices and price path for assets constructed before 1 July 2009.

In accordance with clause 6.12.3(f) of the transitional chapter 6 rules, the AER's refusal to approve EnergyAustralia's proposed annuity model is based on EnergyAustralia's regulatory proposal (which uses an annuity model) and the methodology has been amended from that basis only to the extent necessary to enable the methodology for the control mechanism to be approved in accordance with the transitional chapter 6 rules.

Clause 6.2.8(a)(2) of the transitional chapter 6 rules allows the AER to publish a guideline on the control mechanisms for direct control services. The construction and maintenance of public lighting infrastructure is an alternative control service[1155] which is a sub–class of direct control services.[1156] The statement on alternative control services was published in accordance with clause 6.2.5(e) of the transitional chapter 6 rules and indicated that a limited building block analysis would be employed to determine efficient prices.[1157] EnergyAustralia did not follow that approach for assets constructed before 1 July 2009 and, as a consequence, the AER has amended EnergyAustralia's methodology.

In relation to assets constructed after 30 June 2009, the AER, in the draft decision, decided to modify the basis on which the schedule of fixed prices and price path for those assets is determined. The capital component of those prices will be determined using an annuity method rather than a building block method. The AER noted that it may decide to depart from the statement on alternative control services and if it does so, it must state its reasons.[1158] The reasons for the AER adopting an annuity model for assets constructed after 30 June 2009 are set out in sections 17.6.5 and 17.6.11 of the draft decision.

The AER is not departing from the statement on alternative control services for assets constructed before 1 July 2009, therefore, the AER must change EnergyAustralia's methodology to enable the methodology for the control mechanism to be approved in accordance with the transitional chapter 6 rules.

It is also noted that despite acknowledging that historical asset values could be used within the annuity model,[1159] EnergyAustralia did not submit a revised regulatory proposal which replaced the replacement cost values for assets constructed before 1 July 2009 with depreciated historical cost values.

1155 AER, *Final decision*, section 2.7.
1156 NER, transitional chapter 6 rules, clause 6.2.3A(b)(2).
1157 AER, *Statement on alternative control services*, pp. 4–5.
1158 NER, transitional chapter 6 rules, clause 6.2.8(c).
1159 EnergyAustralia, *Submission on the AER's public lighting supplementary draft decision*, p. 17.

AER conclusion

In light of the submissions made by EnergyAustralia, the AER has reviewed its application of the building block approach to assets constructed before 1 July 2009. Its assessment of the approach against the factors in clause 6.2.5(d) of the transitional chapter 6 rules indicates that a building block approach is an appropriate methodology to calculate capital charges for assets constructed before 1 July 2009. The AER considers that its building block approach better meets the national electricity objective than EnergyAustralia's annuity approach for existing assets as it avoids the windfall gains that would result from that approach while allowing the NSW DNSPs to recover a reasonable return on their investment. The AER also considers that it has correctly exercised its discretion in requiring EnergyAustralia to use a limited building block model to calculate a schedule of fixed charges and price path for assets constructed before 1 July 2009.

17.6.4.2 Capital charge - original funding of the assets in the NSW DNSPs' regulatory asset bases

Under the AER's building block approach, public lighting charges are separated into a capital and maintenance price (tariff 1) and a maintenance only price (tariff 2).

The capital component of tariff class 1 is derived by applying a WACC to the RABs proposed by the NSW DNSPs plus a provision for depreciation. The following sections contain issues raised in relation to the calculation of the capital charge.

AER draft decision

This issue was not discussed in the draft decision.

AER supplementary draft decision

This issue was not discussed in the supplementary draft decision.

Submissions

SSROC noted that the AER has proposed that existing lighting owned and constructed by the NSW DNSPs be classified as tariff class 1. It estimated that more than 95 per cent of EnergyAustralia's public lighting assets are classified as rate 1 which broadly has the same definition as the AER's tariff class 1.[1160]

SSROC claimed that the vast majority of lights on EnergyAustralia's network were first lit by Council Electricity Departments or by County Councils in the decades prior to the creation of the corporatised electricity companies such as Sydney Electricity (1990) and Shortland Electricity (1993). It stated that in most cases the original capital was provided by councils or the county councils and at corporatisation no compensation was paid for those assets (including the public lighting assets) transferred to the new State–owned entities.[1161]

SSROC submitted that it was not clear that EnergyAustralia provided the original capital for the vast bulk of lighting installations in the distribution area and questioned the appropriateness of applying tariff class 1 to the majority of its assets.[1162]

[1160] SSROC, *Submission on EnergyAustralia's revised proposal*, 12 February 2009, p. 5.
[1161] SSROC, 27 March 2009, pp. 5–6.
[1162] SSROC, 27 March 2009, pp. 5–6.

TTEG stated that it was its understanding that the DNSPs had only paid for lights since 1996 and that a significant number of assets in their RABs were customer funded. It expected a reduction of around 23 per cent of the proposed RABs when this was taken into consideration.[1163]

AER considerations

The AER accepts the principle that where a party has funded an asset then that party should not be expected to pay a capital charge. However, the AER has not been provided with sufficient evidence to support the claim that councils had originally funded assets and the date at which this occurred. If the proposed funding occurred in the decade prior to corporatisation then it would seem unlikely that these assets would have a material remaining life.

Further, the onus rests upon the councils to provide evidence that they originally funded the assets and when this occurred. Without any evidence to the contrary, the AER is unable to exclude the asset values from a NSW DNSP's public lighting asset base.

AER conclusion

In circumstances where there is a dispute regarding the original funding of an asset and the time funding occurred, the claimant must present evidence to support their claim. In the absence of evidence, the AER accepts the basis of funding as proposed by the NSW DNSPs with respect to tariff class 1.

17.6.4.3 Capital charge - calculation of the regulatory asset base

AER supplementary draft decision

The AER noted that the opening RABs proposed by Integral Energy and Country Energy and provided by EnergyAustralia and the benchmark RAB's estimated by the AER in its supplementary draft decision were not significantly different. The AER concluded that the approaches used by the NSW DNSPs and provided by EnergyAustralia to calculate remaining lives and depreciation were reasonable and therefore the public lighting opening RABs of the NSW DNSPs were reasonable estimates.[1164]

Submissions

EnergyAustralia stated that as part of its 2005 public lighting decision, IPART rejected its original proposal for depreciation and instead adopted a significant downward revision of the depreciation allowance based on a deferral of depreciation. EnergyAustralia cited a report by Allen Consulting Group to IPART that to back end depreciation may imply much lower prices than would have occurred under the alternative regime and higher prices in the future.[1165]

As a result, EnergyAustralia considered that applying a straight line depreciation approach under values the true cost of its assets as it assumes a higher return of capital

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[1163] TTEG, March 2009.
[1164] EnergyAustralia, *Submission on the AER's supplementary draft decision*, p. 11.
[1165] AER, *Supplementary draft decision*, p. 16.

has been actually received. To remedy this EnergyAustralia stated that the AER must establish the RAB using actual depreciation over the current regulatory control period.[1166]

Table 17.10 shows the derivation of EnergyAustralia's revised closing RAB of $143 million developed using its suggested deferred depreciation.

Table 17.10: EnergyAustralia's proposed public lighting RAB ($m, nominal)

	2004–05	2005–06	2006–07	2007–08	2008–09
Opening RAB	97.8	105.0	113.8	124.6	130.8
Plus indexation	2.9	2.9	3.5	2.1	2.5
Plus capex	9.7	12.1	13.8	11.2	16.9
Less depreciation	–5.4	–6.4	–7.0	–7.5	–8.0
Closing RAB	105.0	113.8	124.6	130.8	142.8

Source: EnergyAustralia, *Submission on the AER's supplementary draft decision*, p. 11.

Integral Energy stated that its 2008–09 RAB was derived by applying a notional inflation rate of 3 per cent, subject to final calculation once the 2008 December quarter data became available. Integral Energy has now calculated the 2008–09 inflation rate to be 4.35 per cent and updated its RAB to $38.0 million.[1167]

REROC expressed concern over the method used by Country Energy to allocate its 2009 closing RAB to individual customers. Based on its own investigations, REROC states that it has discovered a number of inaccuracies with inventories maintained by Country Energy. It considered that Country Energy has had sufficient time since it was established as an entity to organise its data to ensure accurate allocations to customers. REROC requested that the AER, as a condition of agreeing to Country Energy's approach to allocating its RAB, require that Country Energy provide accurate geographic information system based records on the inventory held for each customer within the next 12 months.[1168]

From its analysis, TTEG considered Country Energy's RAB to be reasonable but that the RABs proposed by the other NSW DNSPs were excessive and in the case of EnergyAustralia extremely excessive.[1169]

AER considerations

EnergyAustralia claims that the AER was aware that IPART, when making its determination for public lighting in 2005, set prices based on a deferral of depreciation charges. The AER rejects EnergyAustralia's suggestion that it was aware that IPART had accepted a downward revision of depreciation for EnergyAustralia. The AER stated in its draft decision that 'for the purposes of pricing services provided by existing assets the AER prefers a valuation derived from the previous determination utilising the AER's

[1166] EnergyAustralia, *Submission on the AER's supplementary draft decision,* p. 11.
[1167] Integral Energy, *Submission on the AER's supplementary draft decision,* p. 2.
[1168] TTEG, March 2009, p. 12.
[1169] REROC, pp. 2–3.

formula, on the basis that it is consistent with previous regulatory decisions and the depreciation that has occurred'.[1170]

In addition, in its supplementary draft decision the AER stated that the approaches used by the NSW DNSPs to calculate remaining lives and depreciation were reasonable.[1171]

The AER considers that the suggestion by EnergyAustralia that its previous charges were derived applying deferred depreciation is new information of which EnergyAustralia has not previously sought the AER's consideration of. The AER notes that EnergyAustralia has not provided evidence to support its assertion. The AER also notes that the Allen Consulting Group 2003 report was a discussion note on the 'guidance that may be obtained from economic and other principles for derivation of the allowance for regulatory depreciation to be factored into revenue benchmarks'. The report is not an analysis of the actual depreciation that has occurred within EnergyAustralia's business.

Notwithstanding, the AER notes the findings of Wilson Cook in IPART's 2005 review of EnergyAustralia's public lighting capex where it stated that 'the lack of replacement expenditure in the period 1999 to 2004 in comparison with the depreciation charge taken…ought to be taken into account when fixing prices for the coming period.'[1172]

The depreciation noted in Wilson Cook's report as public lighting depreciation taken from IPART's financial model and the depreciation accepted by the AER is shown in table 17.11.

Table 17.11: Depreciation from IPART's financial model ($m, nominal)

	1998-99	1999-2000	2000-01	2001-02	2002-03	2003-04
Capex	6.5	7.5	5.7	4.7	4.2	10.0
IPART Depreciation	12.6	13.3	14.4	15.1	15.8	16.5
	2004–05	**2005–06**	**2006–07**	**2007–08**	**2008–09**	
AER accepted depreciation	10.9	11.8	12.8	14.0	14.9	

Source: Wilson Cook, *Review of EnergyAustralia's Public Lighting Capital Expenditure and Operating Expenditure*, August 2005, p. 15.

It is difficult for the AER to accept that in the face of the data in table 17.11 that there had been a deferral of depreciation to the magnitude suggested by EnergyAustralia. On the contrary, it would appear there may have been a front loading of depreciation over the previous regulatory control period, 1998–99 to 2003–04.

While the AER acknowledges the concerns of REROC regarding the accuracy of Country Energy's asset allocation, the AER does not consider that revisiting charges

1170 AER, *Draft decision*, p. 330.

1171 AER, *Supplementray draft decision*, p. 13.

1172 Wilson Cook, *Review of EnergyAustralia's Public Lighting Capital Expenditure and Operating Expenditure*, August 2005, p. 16.

within the next 12 to 24 months to account for a re–allocation of assets provides regulatory certainty to customers and Country Energy, or is permitted under the NER.

Notwithstanding, the AER takes very seriously that customers should only be paying cost reflective prices for those assets from which they are receiving services. In balancing the need for cost reflective pricing with the issues of regulatory certainty the AER considers that it is appropriate that Country Energy, Integral Energy and EnergyAustralia provide their public lighting customers with geographic based information on the inventory held for each customer before the end of the next regulatory control period. This will allow customers, and the AER, to verify that the inventory lists are accurate.

AER conclusion

EnergyAustralia's claim for deferred depreciation is new information and not supported by evidence. On this basis, the AER does not accept EnergyAustralia's claim for the inclusion of deferred depreciation to be included in its 1 July 2009 opening RAB.

The AER notes that Integral Energy's 2008–09 RAB was derived by applying a notional inflation rate of 3 per cent subject to final calculation, once the 2008 December quarter data became available. The AER accepts that each NSW DNSP will calculate its 2008–09 closing RAB by applying the actual 2008 December quarter CPI data.

The AER also considers that it is appropriate that Country Energy, Integral Energy and EnergyAustralia provide each of their public lighting customers with geographic based information on the inventory held for each customer before the end of the next regulatory control period.

17.6.4.4 Capital charge – estimation of remaining lives used to calculate depreciation

AER draft decision

In the draft decision, the AER required the NSW DNSPs to allocate their 2009 closing RABs to individual public lighting customers using each customers' individual asset inventories.[1173]

AER supplementary draft decision

In its supplementary draft decision, the AER considered that the approaches adopted by each of the NSW DNSPs to determine their remaining lives was reasonable given the data and time limitations they faced.[1174]

Submissions

SSROC expressed concern about the approach taken by EnergyAustralia to estimate the remaining lives of its assets and that the approach may lead to a higher remaining life for assets than should otherwise be the case.

SSROC stated that EnergyAustralia's submission to IPART's 1998 inquiry on street lighting indicated that the energised date in EnergyAustralia's asset register for street lights is manifestly incorrect. SSROC considered the EnergyAustralia approach to deduct

[1173] AER, *Draft decision*, p. 339.
[1174] It is noted that the AER did not agree with EnergyAustralia using a proportion of the RAB value based on replacement costs.

standard ages from the initial installation date until the asset age fell under the standard life to be inappropriate. It stated that the approach assumes that assets are replaced on a timely basis, which it did not consider to be supported by available evidence and results in a material under–estimation of average asset lives.

SSROC contended that total replacement expenditure as identified in the distribution determination indicated a period of significant under–investment from 1999 to 2003 and higher than expected opex in 2004 to 2008. SSROC contend that this is consistent with having an older than expected asset portfolio.[1175]

EnergyAustralia stated that its asset records show the date on which each public light in service was initially constructed. However, it noted that it did not have sufficiently reliable data about when each public light had been subsequently replaced. It acknowledged that this approach would not be robust for an individual light because some components are replaced before and some are replaced after they reach their standard life. However, EnergyAustralia considered that when applied across 1.3 million public lighting components this assumption was robust.[1176]

AER considerations

The objective for the AER in allocating the closing RAB to individual customers was to produce tariffs that more closely reflect the age of the assets contained in an individual customer's asset inventory. The AER accepted that due to a lack of records relating to public lighting assets installation and replacement it was not possible for the NSW DNSPs to produce this information from actual data sets. For this reason, the AER was prepared to accept an approach that produced a reasonable approximation.

The AER acknowledges SSROC's concerns that assets are not always replaced on the expiry of their useful life. However, the AER accepts the method and asset lives derived by EnergyAustralia because the approach provides a reasonable approximation given the data limitations and that the data used from EnergyAustralia's public lighting database is verifiable.

AER conclusion

The AER does not require a change in the remaining lives of assets estimated by EnergyAustralia for its customers.

Taking into account the AER's considerations on the RAB, depreciation and remaining lives, the AER's RABs for each NSW DNSP to be applied in the calculation of tariffs for assets constructed prior to 1 July 2009 are presented in table 17.12. These values will be updated when the NSW DNSPs final inventories for 2008–09 are known.

1175 SSROC, confidential submission, 3 March 2009, p. 4.
1176 EnergyAustralia, letter to AER, Public lighting schedules calculated for the AER, 30 January 2009.

Table 17.12: AER conclusion on opening RABs of the NSW DNSPs as at 1 July 2009 ($m, nominal)

	Opening RAB proposed by the NSW DNSPs	AER conclusion
Country Energy	15.9	15.9
EnergyAustralia	111.3	111.3
Integral Energy	37.5	38.0

17.6.4.5 Capital charge - rate of return

Consistent with the draft decision, the AER has applied the rates of return applicable to standard control services in calculating the public lighting prices and charges for the NSW DSNPs for this final decision. Issues surrounding the rates of return to be applied to the NSW DNSPs are discussed in chapter 11.

17.6.4.6 Overhead rate assumptions

AER supplementary draft decision

While the AER accepted that there was a case for an overhead premium to reflect the rural nature of Country Energy's network, it did not consider the difference in Country Energy's proposed overhead rates compared to the other NSW DNSPs' rates to be reasonable. The AER considered a 5 per cent premium over and above the plant rate and the materials rate applied by urban DNSPs was reasonable and therefore required Country Energy to remodel its charges applying a plant overhead rate of 25 per cent and materials overhead rate of 25 per cent.[1177]

With respect to the overhead rate for materials, the AER required that the NSW DNSPs demonstrate that the majority of purchases were made in bulk quantities.[1178]

The overhead rate applied to maintenance costs by EnergyAustralia was considered reasonable by the AER.[1179]

Submissions

Country Energy maintained that its material overhead of 48 per cent and plant overhead of 56 per cent were both realistic and reasonable. It stated that its network was the largest by length in Australia and that a just in time approach to asset replacement was not feasible and therefore assets were purchased in bulk and stored in one of three bulk storage facilities. In addition, because of the diversity of assets in place, stocks need to include a variety of different asset types which may often be bulky and require significant storage space. For these reasons, Country Energy claimed that the costs of managing its public lighting inventory are substantial.[1180]

[1177] AER, *Supplementary draft decision*, p. 28.
[1178] AER, *Supplementary draft decision*, p. 29.
[1179] AER, *Supplementary draft decision*, p. 29.
[1180] Country Energy, *Submission on supplementary draft decision*, pp. 7–8.

With respect to its plant overhead, Country Energy claimed that the internal charges applied to public lighting are the same as other network operations and include costs of fuel and maintenance, insurance and other overheads.[1181]

Integral Energy applied a labour content of 65 per cent of operating costs but noted that the AER applied 60 per cent without providing any basis.

AER considerations

The AER acknowledges that as a rural distribution business, Country Energy faces costs that would not be experienced by an urban counterpart. The AER acknowledges that it is clearly more dispersed than the rural networks in Victoria and this of itself would mean that certain costs would be greater. For this reason, the AER considers that a premium of 10 per cent would more reasonably reflect the costs associated with operating in its environment. The AER considers a plant overhead rate of 30 per cent and materials overhead rate of 30 per cent for Country Energy is reasonable.

Integral Energy has calculated and applied a labour content of 65 per cent of operating costs consistent with its standard control services. EnergyAustralia calculated a labour content of 64 per cent of its operating costs. In assessing these proposed labour percentages, the AER considers a labour content of operating costs of 65 per cent to be reasonable and should be used to calculate the NSW DNSPs'tariffs.

AER conclusion

Given the dispersed nature of Country Energy's network the AER considers a plant overhead rate of 30 per cent and materials overhead rate of 30 per cent for Country Energy are reasonable.

The AER considers it reasonable to apply a labour content of 65 per cent of operating costs in calculating the NSW DNSPs tariffs.

17.6.4.7 Taxation

AER draft decision

This issue was not discussed in the draft decision.

AER supplementary draft decision

The AER noted that where an asset has been gifted, Integral Energy had developed an additional charge to allow for the recovery of the tax cost incurred by it for receiving the asset.[1182]

Submissions

WSROC questioned why there was a significant difference between Integral Energy's tariff classes 2 and 4 for a variety of lighting types when the maintenance costs for existing and new assets of the same type should be the same.[1183]

1181 Country Energy, *Submission on supplementary draft decision*, p. 8.
1182 AER, *Supplementary draft decision*, pp. 11, 35.
1183 WSROC, *Submission to the AER Draft NSW Distribution Determination (Public Lighting)*, p. 4.

AER considerations

The differences between Integral Energy's tariff class 2 and tariff class 4 can be attributed to tax.

Where an asset has been gifted to Integral Energy that gift is treated as income for tax purposes. As a result, Integral Energy has made provision for the recovery of this tax liability. The AER considers that where Integral Energy incurs an external tax liability from receiving a gifted asset then it should be entitled to recover that cost from the customer of the services provided by that asset.

Integral Energy stated that there was sufficient uncertainty with respect to the historic arrangements with customers for the recovery of tax on assets gifted in the past and therefore it believed that it was inappropriate to apply a tax recovery component to tariff class 2.

The AER considers that in the absence of customers being aware of the tax liability associated with assets gifted in the past that Integral Energy's approach to these assets is appropriate.

The AER has examined the proposed tariff class 4 to determine if the difference between tariff 2 and tariff 4 is commensurate with a corporate tax rate of 30 per cent. The AER has determined that for each luminaire type, the tax component represents between 27.78 per cent and 28.28 per cent of Integral Energy's tariff class 3 (that is, the capital charge). On this basis, the AER is satisfied that Integral Energy's proposed tax recovery charge in its tariff class 4 is appropriate.

However, this rate should not apply to all customers. The recovery of tax must be only recovered from those customers who receive services from the gifted asset. It is a matter for Integral Energy to satisfactorily disclose and apply the tax element associated with its tariff class 4. It should be noted that the AER's tariff class 4 for Integral Energy, contained in appendix R, includes the tax component set out in appendix S.

AER conclusion

The AER considers that Integral Energy's approach to recover tax associated with gifted assets is appropriate.

To ensure tax is only recovered from those customers who receive services from the gifted asset, Integral Energy will be required to separately publish its maintenance tariff (tariff 4) as prescribed by the AER and the charge relating to the recovery of tax. Integral Energy will be required to apply the latter tariff only to those customers that have gifted an asset. The tax liability associated with gifted assets, as provided in Integral Energy's public lighting model is replicated at appendix S.

17.6.4.8 Past technology decisions

AER draft decision

The AER considered that if the DNSPs had installed lights that were clearly outdated technology and not consistent with good industry practice then there may be a case for recourse. However, the AER noted this is difficult to prove and it had not been provided with any evidence that substantiated claims made by stakeholders.[1184]

The AER also noted that under section 14 of the Public Lighting Code, public lighting customers are to be provided with a choice when a new light is to be installed or an existing one replaced. The AER required the NSW DNSPs to advise customers three months in advance of the need for replacement, so that the customer is able to choose the replacement asset from the list of standard luminaires, and is made aware of the tariff associated with its replacement decision.[1185]

AER supplementary draft decision

This issue was not discussed in the supplementary draft decision.

Submissions

SSROC stated that EnergyAustralia had failed to meet its obligations to ensure that lighting technology practices were efficient and current. It considered that as a result EnergyAustralia has a high cost bulk lamp replacement cycle on residential roads for tubular florescent lighting and high wattage MV lighting on main roads. For example, SSROC stated that for decades EnergyAustralia has installed the 2*20W TF luminaire type and similar luminaires beyond what it considered to be an acceptable time period.[1186] As a result of the installation of the 2*20 TF, there is a high incidence of outage rates and high cost maintenance associated with this luminaire type.

SSROC noted that the AER had accepted significant increases in maintenance costs of EnergyAustralia's TF2*20 watt luminaires and considered that it would be inequitable to reward EnergyAustralia for this past mis–investment by approving these price increases.[1187]

AER considerations

The AER acknowledges SSROC's concerns regarding the higher maintenance costs associated with older technology. To address this issue, the AER has examined the expected failure rates proposed by the NSW DNSPs and has compared these against the proposed improvements in failure rates under a bulk replacement regime.

The AER has assessed maintenance costs on an efficient cost basis irrespective of the choice of technology. This is discussed in greater detail in section 17.5.

AER conclusion

The AER has assessed the maintenance costs associated with all asset types on an efficient cost basis irrespective of the choice of technology.

[1184] AER, *Draft decision*, pp. 332–333.
[1185] AER, *Draft decision*, pp. 332–333.
[1186] SSROC stated that the TF2*20 luminaire was developed around 1958 and the optical characteristics had changed little since then. It claimed that EnergyAustralia continued to install TF2*20 TF lighting until July 2004 when Councils wrote to EnergyAustralia requesting the installation of this lighting type be stopped. SSROC noted that in Victoria, the SECV began a proactive removal program for TF2*20 luminaires in the mid 1980s and completed this by 1990. SSROC, *Submission on EnergyAustralia's revised regulatory proposal*, 12 February 2009, pp. 4–6.
[1187] SSROC, 12 February 2009, pp. 4–6 and SSROC, 27 March 2009, p. 6.

17.6.4.9 Prices and price path (existing assets)

AER supplementary draft decision

The AER requested the NSW DNSPs to recalculate their 2009–10 tariffs and price paths for assets constructed prior to 1 July 2009 based on the inputs and assumptions contained in the supplementary draft decision and presented these results at appendices A, B, and C of the supplementary draft decision for the NSW DNSPs.[1188]

Submissions

REROC stated that they were not convinced that the inflation rate should apply to 100 per cent of maintenance costs if there has already been a price uplift for 60 per cent maintenance costs through the application of a labour escalator. It stated that its members were concerned about possible double counting in the application of labour escalators and inflation to the price path.[1189]

Both Blacktown City Council[1190] and the Hills Shire Council[1191] submitted that the increase proposed in relation to existing assets of 11 per cent and 24 per cent respectively were unreasonable and were of major concern to the councils, particularly if the increase was passed on in one year.

AER considerations

In relation to the concerns raised by REROC, the AER notes that the application of the labour escalator to maintenance costs does not result in a double counting when inflation is applied to the price path. This is because the labour escalator is a real escalator and does not include inflation.

A number of submissions raised significant concerns regarding the proposed price increases. Based on information provided to it by the NSW DNSPs, the AER is of the understanding that the costs approved in the supplementary draft decision would result in initial price decreases for the majority of customers.

However, the AER accepts that an explanation of how prices would move year on year over the next regulatory control period was not satisfactorily explained in the supplementary draft decision.

For the purposes of this final decision, the AER has stipulated an initial annual charge for each customer with fixed annual changes inclusive of forecast inflation specified for each year of the next regulatory control period.

In establishing the fixed rate at which customers' total charges will change annually, the AER has considered a range of different smoothing options to obtain a constant profile to charges. In considering these options, the AER has sought to balance three issues:

[1188] AER, *Supplementary draft decision*, p. 31.
[1189] REROC, 27 March 2006, p.6.
[1190] Blacktown City Council, *Submission on Draft Decision New South Wales Draft Determination 2009-10 to 2013-14 Alternative Control (Public Lighting) Services*, 23 March 2009, pp. 1–2.
[1191] The Hills Shire Council, *Submission on Draft Decision New South Wales Draft Determination 2009-10 to 2013-14 Alternative Control (Public Lighting) Services*, 23 March 2009, pp. 1–21.

- the impact on first year charges stemming from significant step changes from the previous regulatory control period
- allowing for NPV neutral revenue recovery for the DNSPs
- eliminating a significant step change at the end of the next regulatory control period.

Given the profile of the proposed charges it became apparent that the AER would not be able to achieve preferred outcomes on each of the three issues simultaneously. As a result, it has been necessary for the AER to prioritise these issues in order of importance. For this reason, the AER made moving to cost reflective price paths and ensuring NPV neutral cost recovery by the DNSPs to be its principle objectives in establishing a price path.

To achieve this outcome, the AER has developed a price path using a backsolving approach. This approach involved adopting the AER's approved charge for the last year of the next regulatory control period and then developing the lowest straight line path to the first year that would also preserve NPV revenue recovery for the DNSPs.

The approach ensures that there is consistency and certainty between regulatory control periods and allows for a continuation of the existing building block model until all assets have been fully depreciated at which time charges for assets constructed prior to 1 July 2009 will effectively reach a zero value.

The approach results in a relatively flat and stable price path for most customers, however, the downside is that it also results in significant changes in 2009–10 charges compared to 2008–09 charges for some customers. The AER has listed the percentage changes for all customers at appendix Q.

Under the AER's approach some of the DNSPs' customers will experience initial increases in charges for 2009-10. However, the majority of DNSPs' customers will experience initial price decreases and most will receive real decreases in charges over the next regulatory control period.

For Country Energy, the AER expects annual changes for individual customers between 1.5 per cent and 3.9 per cent per annum in nominal terms. For EnergyAustralia, the AER expects annual changes of between –9.5 per cent and 1.1 per cent per annum and for Integral Energy of between 4.0 per cent and 3.6 per cent per annum in nominal terms.

AER conclusion

Based on its smoothing approach, the AER has calculated that charges for most customers will decrease in the first year of the next regulatory control period and then assume a constant year on year change. The schedule of charges applicable to the NSW DNSPs for assets constructed before 1 July 2009 is contained in appendix P.

A comparison of each NSW DNSP's customers estimated total charges for 2009–10 against their estimated 2008–09 charges is contained at appendix Q.

17.7 Assets constructed after 30 June 2009

17.7.1 AER draft decision

In developing their proposed schedule of charges for assets constructed after 30 June 2009, the NSW DNSPs were required to calculate capital charges using an annuity approach. The AER's objective in requiring the NSW DNSPs to use an annuity approach was to convert the capital investment of an individual light into an annual charge that remains constant over the life of the asset. This approach provides certainty and transparency in terms of prices to customers, while at the same time allowing a DNSP to recover an appropriate return on its investment.

The annual annuity capital charge for each public lighting asset was required to be derived adopting the following assumptions:

- efficient material and installation costs
- a standard life of luminaires and brackets of 20 years
- a standard life of poles of 35 years
- a discount rate equivalent to that applied by the AER to standard control services.

In the draft decision, the AER required that the maintenance charges for assets constructed after 30 June 2009 to be the same as that for assets constructed before 1 July 2009.[1192]

17.7.2 Revised regulatory proposals – annuity approach

The NSW DNSPs provided the AER with their respective annuity models. Within these models Country Energy applied a real WACC of 8.11 per cent, EnergyAustralia 7.69 per cent and Integral Energy 8.09 per cent.[1193]

The NSW DNSPs' proposed capital costs for key luminaire types and brackets are presented in table 17.13 and their proposed construction costs for each component are set out in table 17.14.

[1192] AER, *Draft decision*, pp. 340–341.
[1193] Country Energy, *Revised regulatory proposal*, p. 82; EnergyAustralia, *Annuity pricing model; and* Integral Energy, *Annuity pricing model*.

Table 17.13: NSW DNSPs' proposed uninstalled cost per luminaire and brackets ($)

Asset	Country Energy	EnergyAustralia[a]	Integral Energy
80W MBF/MV	101.58	N/A	79.00
2*14W T5	246.00	[redacted]	208.00
42W CFL	153.60	[redacted]	145.00
150W SON/HPS	250.74	[redacted]	196.00
250W SON/HPS	241.58	[redacted]	198.50
Bracket – minor roads (3 meters)	79.12	[redacted]	80.30
Bracket – major roads	289.64	[redacted]	486.04

Sources: NSW DNSPs, *Annuity pricing models*.
(a) EnergyAustralia requested this information be kept confidential.

Table 17.14: NSW DNSPs' proposed construction costs including overheads ($)

	Country Energy	EnergyAustralia	Integral Energy
Luminaire – minor roads	73.26	17.88 + 20% OH on uninstalled luminaire	208.17
Bracket – minor roads	230.42	160.90 + 20% OH on uninstalled cost per bracket	–
Luminaire – major roads	–	35.76 + 20% OH on uninstalled luminaire	217.06
Bracket – major roads	–	321.80 + 20% OH on uninstalled cost per bracket	–
Design	177.30	N/A	N/A

Sources: NSW DNSPs, *Annuity pricing models*.

17.7.3 AER supplementary draft decision

The AER was satisfied that the models provided by the NSW DNSPs correctly calculated an annuity capital charge for public lighting assets to be constructed after 1 July 2009. However, it noted that the models applied different assumptions regarding construction costs and overheads and were not consistent with the draft decision requirements regarding the rate of return to be applied to public lighting.

The AER accepted that the cost of supply of luminaires resulted from a competitive market and that the costs of the associated components (which are part of the purchased luminaire) were reasonable.

The AER noted that Integral Energy's labour rate appeared high, however, when assessed in combination with its labour hours to perform the activity, the AER considered Integral Energy's overall construction costs were reasonable.

Similarly, the AER considered that, in combination, EnergyAustralia's costs were reasonable. However, with respect to major roads, the AER required EnergyAustralia to remodel its tariffs applying a labour duration of 2 hours per light (that is, the same number of hours to construct lights for minor roads).

With respect to Country Energy, the AER did not accept its proposed effective labour rate for design costs. The AER required Country Energy to remodel its charges applying an effective labour rate (that is $79.76/hr) consistent with the labour rate used to construct a light.

The AER did not consider Country Energy's proposed overhead rates to be reasonable. It considered a 5 per cent premium over and above the materials rate applied by urban DNSPs was reasonable and therefore required Country Energy to remodel its charges applying a plant overhead rate of 25 per cent and materials overhead rate of 25 per cent.

Consistent with standard control services, the AER decided the rates of return to apply in the annuity model were the following real rates of return: 7.65 per cent for Country Energy; 7.69 per cent for EnergyAustralia; and 7.71 per cent for Integral Energy.

The AER requested the NSW DNSPs to remodel their capital charges in their annuity models using these rates of return and any revised cost inputs, as noted above.

17.7.4 Issues and consideration

17.7.4.1 Costs associated with an installed luminaire

AER supplementary draft decision

The AER noted that when a luminaire is purchased from a supplier it is often shipped to the DNSP with lamp, photoelectric cell and connection wiring pre-installed. On that basis, the AER did not separately assess these components, rather, it assessed a luminaire as an assembled item.[1194]

The AER considered that the price obtained by the NSW DNSPs from suppliers was reflective of a market price. To substantiate the NSW DNSPs' costs, the AER sought copies of invoices relating to the purchase of luminaires from each NSW DNSP. The invoices indicated that the costs paid by the NSW DNSPs for luminaires were generally consistent with the costs included in their annuity models.[1195]

With respect to Country Energy, the AER did not accept its proposed effective labour rate for design costs and required it to remodel its charges, applying an effective labour rate consistent with the labour rate to construct a light.[1196]

While the AER considered that the total costs of the construction of a luminaire proposed by Integral Energy and EnergyAustralia were reasonable, the AER sought clarification on

[1194] AER, *Supplementary draft decision,* p. 38.
[1195] AER, *Supplementary draft decision,* p. 39.
[1196] AER, *Supplementary draft decision,* pp. 42–43.

the components of Integral Energy's labour rate. With respect to major roads the AER also required EnergyAustralia to remodel its tariffs applying a labour duration of 2 hours.[1197]

Submissions

SSROC stated that EnergyAustralia's luminaire costs were 20 per cent higher than prices obtained by SSROC directly from suppliers. SSROC considered that EnergyAustralia's inclusion of electronic control gear[1198] in its capital cost assumptions was not supported by market information. It noted that the manufacturer's data on ballast lives is rated at 20 years given the operating temperature the ballasts experience in the field. It also stated that EnergyAustralia's own trials of T5 and CFL luminaires indicate ballast failure rates of 0.5 per cent per annum which is below the failure rates predicted by manufacturers. SSROC noted that in its decision on energy efficient lighting in Victoria, the AER found that fair and reasonable capital charges should include a bulk replacement of ballasts at the end of 20 years when the luminaire had reached the end of its depreciable life.[1199]

In terms of the construction costs of a luminaire, SSROC considered that EnergyAustralia's labour assumptions for luminaire replacements appear to be based on those replacements happening on a spot basis (that is, a two person crew doing eight replacements per day). SSROC considered that up to 40 000 bulk luminaire replacements have been made by EnergyAustralia on residential roads since the last pricing review was undertaken (that is, a two person crew doing up to 30 replacements a day in a contiguous area).[1200]

SSROC noted a material difference in the labour assumptions approved by the AER in its decision on energy efficient lighting in Victoria and the assumptions supported in the supplementary draft decision. SSROC noted that 13 to 16 luminaire replacements per day were supported in Victoria whereas 4 to 8 replacements per day were accepted for EnergyAustralia and 16 to 30 fault repairs per day accepted for Victoria and only 8 to 12 for EnergyAustralia.[1201]

AER considerations

The AER's decision on energy efficient public lighting in Victoria concluded that the costs incurred by Victorian DNSPs in providing public lighting services for spot replacement were $193.00 for a 2 x 14W T5 luminaire, $8.00 for a lamp and $13.50 for a photoelectric cell.[1202] These costs do not include installation costs.

The AER considers that the uninstalled costs per luminaire proposed by the NSW DNSPs are broadly consistent with the Victorian decision.

1197 AER, *Supplementary draft decision,* p. 43.
1198 Most artifical light sources other than incandescent lamps require special control gear to start the lamp and control the current after starting. Depending on the type of lamp included, the control gear can take the form of ballasts, igniters or transformers.
1199 SSROC, 27 March 2009, p. 2.
1200 SSROC, 27 March 2009, p. 8.
1201 SSROC, 27 March 2009, pp. 8–9.
1202 AER, *Final decision*, *Energy efficient public lighting charges – Victoria*, February 2009, p. 29.

In addition, the AER has examined the invoices for luminaire costs paid by the NSW DNSPs and is satisfied that these costs are consistent with the luminaire costs proposed by the NSW DNSPs and the costs contained in its Victorian decision.

The AER acknowledges SSROC's concerns regarding EnergyAustralia's proposed ballast lives. In its decision on energy efficient lighting in Victoria, the AER considered that ballasts would perform to a degree that permitted a replacement cycle over a period longer than 8 years but noted that there was also a risk to the distributor of a 20 year replacement cycle.

Due to the limited and disputed evidence on ballast performance, the AER considers that customers should not pay for replacement of ballasts that remain in good working order. Equally, it is important to ensure that the NSW DNSPs are not exposed to undue risk of ballast failure, through non-recovery of expenditure on replacements.

In its Victorian decision the AER accepted the initial costs of replacing ballasts, both for intermittent failure and at the end of their economic life as a capital item. However with respect to the NSW DNSPs the AER considers that further information is required before it can reject EnergyAustralia's position of an eight year life.

For this reason, ballast lives will be further examined as part of the 2014–2019 distribution determination, at which time the DNSPs will need to provide evidence supporting any position with respect to the expected life of ballasts.

In terms of the construction of a luminaire, the AER's decision on energy efficient lighting in Victoria stated that the lack of certainty about the volume of lights to be constructed makes it problematic to assess the fairness and reasonableness of an installation charge.[1203]

The AER notes that the revised labour costs in the Victorian decision provide for an hourly rate of $71.41.

The AER does not consider that there has been sufficient new evidence presented that would cause it to change its views from its supplementary draft decision on the NSW DNSPs proposed labour rates.

The AER notes that the luminaire installation rates suggested by SSROC (30 in a day) are significantly higher than those accepted by the AER in the supplementary draft decision. The AER has also further considered its Victorian decision and considers that 2 luminaire replacements under a bulk replacement program per hour including travelling from pole to pole to be reasonable. Assuming an 8 hour day with travel time of 0.75 hour to and from the depot and 1.25 hours for labour breaks this leaves a productive time of 6 hours. Based on a replacement of 2 luminaires per hour, and a productive time of 6 hours the AER considers 12 luminaire replacements per day as reasonable, or an effective replacement rate of 1.39 hours.

This contrasts with the proposed installation rates on minor roads of 2.75 hours for Country Energy and 2 hours for EnergyAustralia but is consistent with Integral Energy's proposed installation rates.

[1203] AER, *Final decision*, *Energy efficient public lighting charges – Victoria*, February 2009, p. 29.

AER conclusion

The AER is satisfied that the NSW DNSPs labour and capital costs associated with the construction of a luminaire are reasonable.

With respect to ballast replacement, the AER considers that further information is required before it can reject EnergyAustralia's position of an 8 year life. Ballast lives will be further examined at the next regulatory reset where the NSW DNSPs will need to provide evidence in relation to the expected life of ballasts. In the interim, the AER has accepted the DNSP's proposals on ballast lives. The AER considers the efficient rate of bulk luminaire replacement per day is 12 luminaires.

17.7.4.2 Assumed standard lives of brackets and supports

AER draft decision

This issue was discussed in the draft decision in the context of brackets being changed with the replacement of luminaires.[1204] A decision was not made in respect of the standard life of a bracket.

AER supplementary draft decision

The AER noted that an assessment of bracket costs should be considered in conjunction with luminaires as both assets have the same asset life, that is, when a luminaire was originally installed it was done so with a bracket of equal expected life.[1205]

Submissions

SSROC stated that it has not been EnergyAustralia's practice to replace brackets in conjunction with bulk luminaire replacements, that is, every 20 years. With respect to main roads, SSROC claimed that the luminaire and bracket replacements do not coincide. In support of its claim, SSROC stated that in 2003, EnergyAustralia's capex figures were not large enough to support a number of bracket replacements consistent with the 8252 luminaires that were replaced.[1206]

SSROC noted that in the Essential Services Commission of Victoria's (ESCV) draft decision on energy efficient public lighting charges, an age of 35 years was accepted as the reasonable economic life of a bracket. SSROC considered that there did not appear any inherent technical reason why a vertical galvanised pole should have a life of 35 years and that a galvanised piece of tubing (the bracket) should have a life of only 20 years. SSROC stated that proper treatment of the average asset life of brackets, particularly those on main roads with high capital costs, was essential to the calculation of efficient prices.[1207]

[1204] AER, *Draft decision*, pp. 330–331.

[1205] AER, Supplementary d*raft decision*, p. 39.

[1206] SSROC, *Submission on AER draft decision*, 2 February 2009, p. 6; and SSROC, *Submission on supplementary draft decision*, 27 March 2009, pp. 7–8.

[1207] SSROC, *Submission on AER draft decision*, 2 February 2009, p. 6; and SSROC, *Submission on supplementary draft decision*, 27 March 2009, pp. 7–8.

TTEG did not support brackets being attributed a 20 year life to match the luminaire. TTEG also considered that long-lived assets such as poles and columns, which may contribute up to 50 per cent of the RAB, may have a 35 year life or longer.[1208]

EnergyAustralia did not accept the AER's view that supports should have a standard life of 35 years instead of 20 years. It claimed that in extending the asset lives of supports it would require opex in addition to its original forecast in its June 2008 regulatory proposal.[1209]

AER considerations

The AER notes SSROC's claim of an inconsistency between the number of bracket replacements and the number of luminaire replacements in EnergyAustralia's 2003 capex data. Based on data provided by EnergyAustralia, the AER has not been able to substantiate SSROC's claim. Notwithstanding, the AER does consider that there is sufficient evidence to warrant re-examination of bracket and support lives.

The AER notes the findings of Wilson Cook in IPART's review of EnergyAustralia's public lighting capex that concluded that 'brackets arms and steel standards ought to be assigned longer lives with a consequential reduction in replacement expenditure and in depreciation charges'.[1210] Similarly, in its 2005 review for EnergyAustralia of its public lighting costs, PB Associates concluded that the range of standard lives for public lighting assets ranged from 20 to 60 years with an average of 30 years and considered that EnergyAustralia's average asset lives to be at the lower end of the average.[1211]

The AER has also considered the findings of the ESCV in its 2004 review of public lighting charges[1212] and the ESCV's 2008 draft decision on energy efficient lighting charges[1213] which both concluded that a bracket age of 35 years was appropriate. The AER also found the 35 year standard life for brackets was also applied to public lighting assets in the ACT.

In addition, information obtained from EnergyAustralia suggests that only one recent bulk luminaire replacement program incorporated a standard bulk replacement of associated brackets.

With respect to assets constructed prior to 30 June 2009, the AER understands that the previous regulator, IPART, allowed the NSW DNSPs to apply a standard life of 20 years for brackets. For reasons of regulatory certainty the AER does not consider that it is appropriate to reverse a decision that has already been accepted and implemented by the previous regulator and for that reason accepts an asset life of 20 years for brackets installed prior to 30 June 2009.

However, it is the AER's view that the life of a bracket should be 35 years for the reasons discussed above. While it has accepted a different age for assets constructed prior to

1208 TTEG, p.12.

1209 EnergyAustralia, revised regulatory proposal, p. 190.

1210 Wilson Cook, *Review of EnergyAustralia's Public Lighting Capital Expenditure and Operating Expenditure*, August 2005.

1211 PB Associates letter to EnergyAustralia, 2 June 2005, PBA ref 158314-001 see http://www.ipart.nsw.gov.au/search/search_results.asp?sidebarSearchTextBox=lighting

1212 ESCV, *Final Decision - Review of Public Lighting Excluded Service Charges*, August 2004

1213 ESCV, *Draft Decision – Energy Efficient Public Lighting Charges*, November 2008, p. 24.

1 July 2009, the AER considers that it is now appropriate to differentiate between its views and those of IPART and to provide customers with future certainty. For that reason, the AER considers a 35 year standard life for brackets constructed after 30 June 2009 is reasonable.

AER conclusion

With respect to assets constructed prior to 1 July 2009, the AER considers that the standard lives of brackets should remain at 20 years. However, in regard to assets constructed after 30 June 2009, the AER considers that the standard life of brackets and supports should be consistent with the 35 year standard life used in other jurisdictions.

17.7.4.3 Early replacement of assets at a customer's request

AER draft decision

In the draft decision, the AER established a tariff class (tariff class 6) for public lighting assets owned by a NSW DNSP but replaced at the request of a customer before the end of their economic lives. The AER indicated that this tariff would be based upon a residual asset value calculated for the replaced asset using remaining lives determined through an assessment of the asset's condition and type, or a default position would apply. The default position was that, unless it could be demonstrated that the remaining life of an asset was more than 10 years, the residual asset value was to be based on a default age of at least three quarters of its economic life.[1214]

Revised regulatory proposals

Country Energy agreed that, where an assets classification is subject to tariff class 1 or 3 and early replacement has been requested by the customer, residual asset charges would be payable by customers.[1215]

Integral Energy stated that the rates for tariff class 6 would be either tariff class 3 or 4 (depending on who funded the capital) with an upfront payment for the residual capital value determined at the time of the customer's request for early replacement. Integral Energy noted that it had not submitted charges for tariff class 6, as it believed there were too many variables relating to the residual asset charge to be able to develop an appropriate tariff to cover all scenarios.

EnergyAustralia accepted that there were better approaches to calculate a proxy for the residual asset value due to early replacement of a public lighting component than that proposed by it in its June 2008 regulatory proposal.[1216] It proposed a new approach to calculate its rate 4 tariff (the equivalent to the AER's tariff class 6). Under its proposed approach, the replacement cost for each component is depreciated by 75 per cent to take into account the likely age of assets that are replaced under rate 4. The remaining capital value is then converted to an annuity. This capital charge was to be added to EnergyAustralia's rate 1 prices (equivalent to AER's tariff class 3) for brackets and luminaires to produce a new rate 4 price. That is, EnergyAustralia's proposed rate 4 prices were 25 per cent higher than its rate 1 prices.[1217]

[1214] AER, *Draft decision*, p. 340.
[1215] Country Energy, *Revised regulatory proposal*, p. 79.
[1216] EnergyAustralia, *Revised regulatory proposal*, p. 191.
[1217] EnergyAustralia, *Revised regulatory proposal*, p. 191.

EnergyAustralia considered its approach to be a fair and reasonable method of estimating the lost depreciation associated with the early replacement of public lighting components. It also considered that its proposed approach was consistent with the draft decision and that this method should apply unless data is found that suggests that the remaining life of the asset in question is more than 10 years.[1218]

AER supplementary draft decision

The AER accepted that there were a number of variables relating to the calculation of the residual capital value for an asset being replaced early at a customers request and therefore did not require the NSW DNSPs to publish tariffs for tariff class 6 (now tariff class 5) upfront.[1219] The AER considered that these tariffs, primarily the residual capital value, would need to be calculated at the time of agreement with the customer to undertake the replacement.

The AER did not consider that the approach proposed by EnergyAustralia to calculate its rate 4 tariff (equivalent to the AER's tariff class 6) in its revised regulatory proposal was appropriate as it used a current replacement value for the asset that is being replaced early rather than the depreciated original capital cost of the asset. The AER stated that its tariff class 6 (now tariff class 5) was the combination of:[1220]

- an annual charge to recover the residual capital value of the asset to be replaced
- the efficient maintenance costs associated with the new asset
- the relevant annual capital charge associated with the new asset.

Once the residual value of the asset has been returned to the NSW DNSP, tariff class 6 (now tariff class 5) would no longer apply and the appropriate tariff would be tariff class 3 or 4, depending upon who funded the capital associated with the new asset.[1221]

The AER considered that when a customer requests replacement of existing assets before the end of their economic life, the NSW DNSP would calculate a residual capital charge for the asset being replaced. This residual capital charge is to be calculated by the NSW DNSP based on the depreciated value of the assets original cost and a remaining life determined through an assessment of the assets type and/or condition or by the application of the AER's default remaining life value. The AER indicated that the residual capital charge for the asset being replaced early could be either a one–off charge or an annual charge calculated for the duration of the remaining life of the asset.[1222]

Submissions

Integral Energy considered that the payment for the residual value of the assets replaced early at a customer's request should be an upfront payment, as an annual payment for the residual asset charge would require the creation of a series of prices for individual replacement projects which will need to be tracked until they reach zero. It stated that

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[1218] EnergyAustralia, *Revised regulatory proposal*, p. 191.

[1219] In its supplementary draft decision, the AER decided to change its tariff class designations to reflect the fact that tariff class designation is primarily driven by the capital funding arrangements and not necessarily ownership arrangements. As a result the AER decided to merge tariff classes 4 and 5 into tariff class 4 and tariff class 6 therefore became tariff class 5.

[1220] AER, *Supplementary draft decision*, pp. 46–47.

[1221] AER, *Supplementary draft decision*, p. 47.

[1222] AER, *Supplementary draft decision*, p. 47.

such an approach would be difficult to implement using its current systems and that an upfront payment means that the billing system would only need to accommodate tariff classes 3 and 4.[1223]

Country Energy agreed that the residual capital charges should be calculated at the time of agreement with the customer and with the method proposed in the draft decision. It understood that residual capital charges for early replacement of the luminaire would be recovered immediately.[1224]

SSROC stated that it welcomed the AER's conclusions in relation to potential double counting and arbitrary age assignments with regards to EnergyAustralia's proposed rate 4 tariff (equivalent to the AER's tariff class 6). However, SSROC stated that it had continuing concerns about EnergyAustralia's use of current (replacement) costs rather than the actual depreciated cost of the original installation to calculate residual capital charges.[1225]

SSROC also queried why councils would be liable for higher on–going tariff for a new asset (than would otherwise be the case) if they had agreed to pay for the residual condition based capital charge on the asset being replaced before the end of its useful life.[1226]

AER considerations

In its draft decision, the AER indicated that the residual charge for the replacement of assets before the end of their useful life could be paid upfront or through annual payments. However, having reviewed the issues raised by Integral Energy and EnergyAustralia regarding the complexities posed by annual payments for the NSW DNSPs billing systems, the AER accepts that the payment for the residual value of assets replaced at a customer's request should be an upfront payment only.

Tariff class 6 (now tariff class 5) will be defined as the amount payable by a customer based on an agreed method between it and the relevant NSW DNSP for determining the residual capital value of the assets to be replaced. The amount will need to be paid upfront by the customer at the time an agreement is entered into to undertake early replacement of the asset in question. The residual capital value is to be based on the depreciated original capital cost of the assets to be replaced. The remaining life may need to be determined through a review of the type of asset being replaced and its condition. However, unless a review of the type of asset and its condition can demonstrate that the remaining life of an asset is more than 10 years, the residual capital value of the asset should be based on a default age of at least three quarters of its economic life.

This approach means that the new asset replacing the old asset will simply be charged for under tariff class 3 or tariff class 4, depending upon who funded the capital for these assets. The AER considers that this approach addresses the issues raised by Integral Energy and EnergyAustralia regarding the complexity of billing arrangements and also avoids any confusion as to the tariffs to be paid for those assets replaced before the end of their standard lives at the request of a customer.

1223 Integral Energy, *Submission on supplementary draft decision*, 27 March 2009, attachment 1, p. 2.
1224 Country Energy, *Submission on AER Supplementary draft decision*, 27 March 2009, p. 10.
1225 SSROC, *Submission on AER draft decision*, 12 February 2009, p. 8.
1226 SSROC, *Submission on AER draft decision*, 12 February 2009, p. 8.

The AER shares the concerns raised by SSROC regarding EnergyAustralia's proposal to use replacement costs to calculate the residual asset charge. In its supplementary draft decision the AER stated that it did not consider it was appropriate to use current replacement costs to calculate tariff class 6 (now tariff class 5).

SSROC also queried why councils would be liable for a higher on–going tariff for a new asset if they had agreed to pay for the residual condition based capital charge on the asset being replaced before the end of its useful life.[1227] In its supplementary draft decision, the AER stated that it would allow the residual capital value of the assets replaced early to be paid for upfront or paid through an annual payment. If a customer elected to pay through an annual payment this would have resulted in tariff class 6 (now tariff class 5) being higher than the tariffs applying to new assets (either tariff class 3 or tariff class 4). However, as the AER has now decided to only allow an upfront payment for the residual capital charge on assets replaced early, the relevant tariffs for the new assets will now be tariff class 3 or tariff class 4, depending upon who provides the capital funding.

To assist in calculating any future residual charges, the AER requires all new assets to have their type, cost and date of installation recorded on each NSW DNSPs public lighting asset register. The AER also considers a discount should be provided on maintenance costs if asset replacement is aligned with a DNSP's bulk maintenance cycle.

AER conclusion

Tariff class 6 (now tariff class 5) is defined as the charge calculated at the time of agreement by a customer to replace the asset early using a method agreed with the NSW DNSP for determining the residual capital value of the asset (table 17.2). The charge is to be paid for upfront. The residual asset value calculated for the replaced asset is to be based on the depreciated original capital cost of the asset, with the remaining life determined through an assessment of the asset type and/or condition or the AER default value. The new asset will attract tariff class 3 or tariff class 4, depending upon who funded the capital for these assets.

17.7.4.4 Prices and price paths (new assets)

AER draft decision

The draft decision indicated that following the calculation of an annuity charge for 2009-10, subsequent price changes are to be calculated multiplying the first year's schedule of charges by an appropriate escalator (for example, CPI). It required each NSW DNSP to nominate an escalator.[1228]

Revised regulatory proposals

Country Energy did not provide an escalation rate.

EnergyAustralia proposed an escalation rate based on a ratio of labour costs relative to the expected revenue from public lighting services multiplied by the real labour escalation rate in NSW for the electricity, gas and water (EGW) sector.[1229]

[1227] SSROC, *Submission on AER draft decision*, 12 February 2009, p. 8.
[1228] AER, *Draft decision*, p. 339.
[1229] EnergyAustralia, *Revised regulatory proposal*, p. 173.

Integral Energy proposed an escalation rate weighted according to the movement in capital costs and CPI.[1230]

AER supplementary draft decision

The AER stated that it would apply CPI as defined in its draft decision as the annuity tariff escalator. It accepted that a composite escalator may be appropriate but did not consider it had sufficient information to assess EnergyAustralia's and Integral Energy's escalators.[1231]

Submissions

Integral Energy sought clarification regarding the proposed price paths. It believed that the draft decision reflected a nominal price path. Integral Energy considered that this approach was inconsistent with the application of real escalators in the decision on standard control services and could lead to confusion among stakeholders. Integral Energy believed that a price path should be expressed in real terms with the CPI adjustment made annually, consistent with standard control services.[1232]

Integral Energy agreed with the AER's position that escalators should reflect the movement in input costs. It stated that it would accept the principle of escalating public lighting capex by 50 per cent of the NSW EGW real labour escalation rate in addition to inflation.[1233]

REROC supported the AER's proposal that the forecast CPI be used as the appropriate escalator for the price path to apply to charges for assets constructed after 30 June 2009.[1234]

TTEG supported the AER's approach of applying CPI until it had a full understanding of cost impacts.[1235]

AER considerations

Under an annuity approach the charges developed by the models are fixed maximum prices in that they remain constant for the life of the asset with the exception of escalation applied.

The AER has reviewed the escalation, or inflation, rates proposed by the NSW DNSPs to apply to each year's prices developed under the annuity model.

The AER acknowledges Integral Energy's claim that 50 per cent of the capital costs of a public light are labour. However, the AER considers that such costs were likely to be included in base cost estimates of its construction costs of new assets and that departures from CPI escalation for the purposes of the annuity model were not warranted.

With respect to maintenance charges on the other hand, the AER considers that for a pure labour activity where the base cost is not fixed, that it is appropriate for these costs to be

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[1230] Integral Energy, *Revised regulatory proposal*, p. 96.
[1231] AER, *Supplementary draft decision*, p. 49.
[1232] Integral Energy, *Submission on supplementary draft decision*, 27 March 2009, p. 2.
[1233] Integral Energy, *Submission on supplementary draft decision*, 27 March 2009, p. 2.
[1234] REROC, p. 8.
[1235] TTEG, p. 19.

indexed applying a rate more specific than general price movements. For this reason, the AER has accepted maintenance charges escalated by the forecast NSW EGW real labour escalation rate in addition to inflation.

AER conclusion

The schedule of prices for 2009–10 applicable to the NSW DNSPs for assets constructed after 30 June 2009 is contained in appendix R.

These prices will be adjusted annually by December quarter CPI data as published by the Australian Bureau of Statistics with the maintenance component indexed by the AER's forecast real labour escalators (table 17.16).

The AER has accepted maintenance charges indexed with the forecast NSW EGW real labour escalation rate in addition to CPI.

17.8 Transitional issues

17.8.1 Timing of application of new tariffs

AER draft decision

In the draft decision, the AER stated that different tariffs would apply to assets constructed before 1 July 2009 compared with those assets constructed after 30 June 2009.[1236]

Revised regulatory proposals

In its revised regulatory proposal, Integral Energy stated that there is a potential for some customers to commit to new public lighting installations before the new rates are finalised, but for construction not to be completed until after 1 July 2009. It sought clarification as to whether the post July 2009 rates apply to assets commissioned after the cut off date, substantively constructed but not commissioned or committed via acceptance of a quotation.

AER supplementary draft decision

In its supplementary draft decision, the AER stated that new tariffs will apply if a customer accepts a quotation for construction of new assets from the relevant NSW DNSP after 30 June 2009.[1237]

Submissions

Integral Energy stated that where it and a public lighting customer agree on a bulk luminaire replacement program, the arrangements detailed in the supplementary draft decision should apply. However, it stated that the new public lighting tariffs should also apply in situations where an individual existing luminaire is replaced after 30 June 2009 for reasons including vandalism, motor vehicle accidents or obsolete fittings with no available spares.[1238]

[1236] AER, *Draft decision*, p. 337.
[1237] AER, *Supplementary draft decision*, p. 52.
[1238] Integral Energy, *Submission on supplementary draft decision*, 27 March 2009, attachment 1, p. 3.

TTEG supported the AER's approach that the new tariffs will apply if a customer accepts a quotation of new assets from the relevant NSW DNSP after 30 June 2009.[1239]

AER considerations

The AER agrees with Integral Energy that where it and a public lighting customer agree on a bulk luminaire replacement program, the arrangements detailed in the supplementary draft decision should apply. That is, if the date of acceptance of the quotation for construction of the new assets is after 30 June 2009 then tariff class 3 or 4 will apply, depending upon who has funded the capital.

Spot replacements may be undertaken by NSW DNSPs during maintenance cycles and an inoperable asset may be replaced by a NSW DNSP at that time. The AER agrees with Integral Energy that either tariff class 3 or 4 (depending upon who funds the capital) should apply in these situations where an individual asset is replaced after 30 June 2009.

AER conclusion

Either tariff class 3 or 4 (depending upon who funds the capital) will apply if a customer accepts a quotation for construction of new assets (for example, a bulk luminaire replacement program) from a NSW DNSP after 30 June 2009. Similarly in relation to the individual replacement of assets, tariff class 3 or 4 will apply if the asset is replaced after 30 June 2009.

17.8.2 Introduction of new assets during the next regulatory control period

Revised regulatory proposals

EnergyAustralia asked what approval process will operate in relation to the tariffs to apply to new types of public lighting assets introduced by a NSW DNSP during the next regulatory control period.[1240]

AER supplementary draft decision

The AER concluded that if a NSW DNSP wishes to offer a new public lighting asset during the next regulatory control period it will need to make an application to the AER for approval of the efficient capital and maintenance charges associated with the asset, prior to the asset being offered to the NSW DNSP's customers.[1241]

Submissions

Integral Energy considered that a six month time frame for a decision on the price for a new type of public lighting asset was too long and would impact on its ability to respond to customer requests for the new installation of energy efficient luminaires in a timely manner. It believed that the time taken to make a decision on any application should be three months and that this timeframe could be extended if required with the agreement of the NSW DNSP and the AER.[1242]

[1239] TTEG, p. 4.
[1240] EnergyAustralia, discussion with the AER, 23 February 2009.
[1241] AER, *Supplementary draft decision*, p. 53.
[1242] Integral Energy, *Submission on AER draft public lighting determination*, attachment 1, p. 3.

TTEG supported the AER's approach to the introduction of new assets over the period.[1243]

AER considerations

The AER considers that a period of up to six months is required to properly assess a NSW DNSP's proposal and consult with interested parties on the tariff applicable. Such a period allows for the AER to undertake a transparent process and allows all interested parties to inform the AER's considerations. The AER notes that the conclusions reached in reviewing the efficient maintenance and capital costs associated with the asset are likely to have broader implications in that it may establish a benchmark by which the AER will assess later proposals.

The AER will make a decision on the timetable for consideration of the application at the time it is received. Subsequent applications on a similar asset type may be able to be assessed in a shorter timeframe without any reduction in the efficiency or transparency of the process. However, the period of time needed to assess a pricing application will depend upon the quality of information provided by the NSW DNSP. Robust and independently corroborated data will assist in speeding up the assessment process.

AER conclusion

The AER will make a decision on the timetable for consideration of an application on a new public lighting asset when the application is received from the NSW DNSP. The AER notes, however, that AER considers that a period of up to six months may be required to properly assess the tariffs applicable to a new asset (for example, a new energy efficient luminaire).

17.8.3 Transition from Country Energy's tariff type 2 to AER tariff classes

AER supplementary draft decision

This issue was not discussed in the AER's supplementary draft decision.

Submissions

REROC stated that most lighting in the Riverina (southern NSW) region is currently priced under a Country Energy tariff known as tariff type 2. Under this tariff the initial capital costs are paid for by councils or developers and the ongoing charges for the asset include components for the maintenance and replacement of the asset.[1244]

REROC referred to monies that Country Energy had collected through its current rate 2 tariff and believes that up to half of the public lighting charges collected by Country Energy and its predecessor organisations should have been held in trust, for the purpose of asset replacement. It stated that the funds should be substantial and unless this issue is addressed in the final determination it was concerned that Country Energy will view those funds as windfall profits. It sought an indication from Country Energy on the amount of funds it has collected from councils and how it intends to apply these funds to the replacement of the pre–1 July 2009 assets.[1245]

[1243] TTEG, p. 4.
[1244] REROC, p. 4.
[1245] REROC, p. 5.

REROC stated that the draft decision did not include a tariff offering similar provisions, as the AER's tariff class 2 is a maintenance only tariff and therefore tariff type 2 assets would become stranded. As such, it considered that councils will have to pick up the cost of capital replacement and transition to the new tariff class 2 or be forced to transition to tariff class 1. It stated that it supported the inclusion of an additional 'Customer funded, DNSP maintained' tariff with charges based on maintenance cost and a capital charge to fund the future replacement of the asset that does not include a return on capital component.[1246]

Country Energy acknowledged that its existing tariff type 2 includes a component representing a contribution towards the future replacement of those tariff type 2 assets currently in existence. It proposed to apply the AER's tariff class 2 (maintenance only) to its existing tariff type 2 tariffs from 1 July 2009.[1247]

Country Energy also stated that it retains its existing commitment for the future replacement of those assets to which the tariff type 2 is currently applied. It stated that its commitment was to replace public lighting assets currently charged under tariff type 2 and in existence at the date of the AER's final determination. It proposed that upon the first replacement of those assets tariff class 4 (maintenance only) would apply. It stated that capital charges would only apply in the future if the assets were replaced a second time and the customer elected not to fund the replacement itself (that is, tariff class 3 would apply).[1248]

Country Energy considered that its proposed approach retained the AER's requirement for appropriate recognition of past customer contributions to the replacement of existing assets. It also considered that the AER's final determination should provide for the transfer of existing type 2 assets to the AER's tariff class 2. Country Energy noted that its proposal did not extend to the early replacement of type 2.[1249]

AER considerations

In general, for assets constructed before 1 July 2009, the AER requires that these assets move across from their existing tariffs to the AER's tariff classes 1 and 2, depending upon who funded the capital for them. However, as the current charges for Country Energy's tariff type 2 assets include a contribution towards the replacement of the asset in the future it is not appropriate for these assets to move to the AER's tariff class 1 on 1 July 2009. The AER accepts Country Energy's proposal that, in the first instance, the AER's tariff class 2 be applied to Country Energy's existing tariff type 2 assets from 1 July 2009. This means that such assets will only be charged efficient maintenance costs and would no longer incorporate an element toward the future replacement cost of the asset.

Given that monies have been collected by Country Energy through tariff type 2 assets it is appropriate that Country Energy fund the first replacement of assets currently covered by tariff type 2. The AER agrees with Country Energy that when replacement occurs it is appropriate that assets currently charged tariff type 2 move across to the AER's tariff

[1246] REROC, p. 4.
[1247] Country Energy, *Revised regulatory proposal*, pp. 79–80.
[1248] Country Energy, *Revised regulatory proposal*, pp. 79–80.
[1249] Country Energy, *Revised regulatory proposal*, pp. 79–80.

class 4 (maintenance charge only). However, for subsequent replacements of the asset the relevant tariff class will be either tariff class 3 or 4 depending upon who funds the capital.

The AER does not believe that an additional 'customer funded, DNSP maintained' tariff is required. It notes that councils are able to fund the capital and installation costs themselves either through savings or through borrowing. Alternatively, they can require the NSW DNSP to bear the capital and installation costs and have tariff class 3 applied to those assets (which includes a return on and of capital). The AER considers that its approach is less administratively complex and should assist in the development of a competitive market for public lighting services.

The AER agrees with REROC that Country Energy will need to keep and provide its customers with accurate records of its pre–1 July 2009 assets. As soon as possible after the release of this final decision, Country Energy should provide its customers with a list of its pre–1 July 2009 assets and advice as to which of these assets are tariff type 2 assets. This will allow customers to properly budget for its existing lights, that is, whether it will be responsible for the next replacement or only for the maintenance element. Country Energy should then keep accurate records on when pre–1 July 2009 assets were replaced and be able to provide these records to its customers upon request.

AER conclusion

The AER accepts Country Energy's proposal that assets currently on its tariff type 2 transfer to the AER's tariff class 2 on 1 July 2009. It also accepts Country Energy's proposal that the first replacement of these tariff type 2 assets be funded by it and be charged under the AER's tariff class 4 (maintenance only). However, for subsequent replacements of the asset the relevant tariff class will be either tariff class 3 or 4 depending upon who funds the capital. The AER also requires that Country Energy keep and provide to its customers accurate records of its pre–1 July 2009 assets so that they can properly budget for the replacement/maintenance of their existing lights.

17.8.4 Transition from Integral Energy's schedule 2 to AER asset classes

AER supplementary draft decision

This issue was not discussed in the supplementary draft decision.

Submissions

WSROC stated that in Integral Energy's service area, a significant portion of public lighting assets are constructed by Councils or developers to Integral Energy's standards and then gifted to Integral Energy. It indicated that these assets are schedule 2 assets and Integral Energy has responsibility for maintenance of the asset and for replacement of the equipment. WSROC stated that the AER's approach does not include this requirement and sought clarification on: [1250]

- What was to happen to the accumulated capital contributions paid by councils as part of schedule 2 tariffs to fund the future replacement of schedule 2 assets?
- What basis schedule 2 assets are to be replaced in the future if they are classified as the AER's tariff class 2 assets?

[1250] WSROC, March 2009, p. 5.

WSROC stated that there did not seem to be a feasible contestable regime or precedent for the separation of lighting repair versus replacement work involving existing assets as under the NSW Code of Contestable Works. Councils are not able to authorise accredited service providers to work on existing Integral Energy assets. In effect, WSROC states that the replacement of contributed assets will be a non–contestable monopoly service of Integral Energy, as it is at present. In these circumstances WSROC indicated that the AER's tariff class 2 should include the requirement for Integral Energy to replace assets installed prior to 30 June 2009 and that the capital cost of the replacement assets installed after 30 June 2009 should be made explicit in the AER's final determination.[1251] WSROC also noted that Integral Energy's current price list gives clear 'Capital Provision' costs for a wide range of current standard equipment.

AER considerations

Integral Energy currently charges for public lighting services under two schedules, schedule 1 and schedule 2. Under schedule 1, Integral Energy provides the capital funding up to a pre–determined limit for each type of public lighting asset and also funds all operating costs relating to the service. Under schedule 2 the developer or customer funds the capital costs of installation and Integral Energy undertakes the maintenance and replacement of the equipment.

The AER asked Integral Energy whether a sinking fund for replacement of schedule 2 assets had been established and, if so, how much had been accumulated in the fund, how much had customers contributed to it and how did Integral Energy intend to return these monies to customers. In response, Integral Energy stated that the sinking fund referred to by WSROC did not exist and that Integral Energy's schedule 2 prices do not include a recovery of return of, or on, the capital invested. Integral Energy advised that when it replaces a schedule 2 luminaire and funds the replacement itself, it is entitled to charge a schedule 1 price for that luminaire (which includes recovery of capital and maintenance).[1252]

The AER considers that WSROC has misinterpreted Integral Energy's schedule 2 tariff definition. While the tariff definition indicates that Integral Energy provides for the replacement of the equipment. The AER understands that this places a responsibility on Integral Energy to undertake the next replacement, not that the tariff includes a capital provision that will cover the cost of replacing the current asset when it comes to the end of its life. It is noted that this is different to Country Energy's existing type 2 asset where the charge includes a contribution towards the replacement of the asset.

Integral Energy also advised that if a schedule 2 (or AER's tariff class 2) asset requires replacement, it would undertake this work. It stated that it would fund and undertake the replacement of the luminaire with the nearest standard equivalent luminaire. It advised that once the replacement was completed the price applicable for the replacement luminaire would be tariff class 3. However, should a council wish to fund the capital then tariff class 4 would apply and Integral Energy stated that it would replace the luminaire

[1251] WSROC, March 2009, pp. 5–6.
[1252] Integral Energy, emailed response to AER questions, 2 April 2009.

and then invoice the council for the standard capital amount built into tariff class 3 price.[1253]

The AER considers that it is implicit that NSW DNSPs are responsible for the replacement of all public lighting assets unless a customer wishes to engage an accredited contractor to undertake the replacements. The AER agrees with Integral Energy that in relation to the situation raised by WSROC that if the asset cannot be repaired then it would be replaced by Integral Energy and the council would pay the AER's tariff class 3, unless the council agreed to pay the capital and installation costs upfront (in this latter case only tariff class 4 would apply).

WSROC also stated that the AER's tariff class 2 should include the requirement for Integral Energy to replace assets installed prior to 30 June 2009 and that the capital cost of the replacement assets installed after 30 June 2009 should be made explicit in the final determination. As stated above, the AER considers that NSW DNSPs are implicitly responsible for the replacement of all public lighting assets unless a customer wishes to engage a contractor to undertake the replacements. While the capital cost of assets has not been made explicit, the AER notes that the capital cost can be easily calculated by subtracting the tariff class 3 price from the tariff class 4 price.

AER conclusion

The AER has confirmed that Integral Energy's schedule 2 tariffs do not include a capital element towards the replacement of assets, rather that Integral Energy would be responsible for the replacement. The AER also considers that it is implicit that NSW DNSPs are responsible for the replacement of public lighting assets unless a customer wishes to engage an accredited contractor to undertake this work.

17.9 Compliance mechanism

AER draft decision

The AER stated that a compliance regime should be robust and administratively simple, where possible, to minimise costs on both the DNSPs and the AER. It considered that compliance with the control mechanism could be demonstrated through an annual approval of changes to the schedules of prices. The AER stated that each DNSP must submit its revised schedules of prices, that will apply in a regulatory year, 9 weeks before the commencement of each regulatory year in the next regulatory control period.[1254]

Submissions

No submissions were received on this issue.

AER considerations

Clause 6.12.1(13) of the transitional chapter 6 rules requires the AER's distribution determination to include a decision on how compliance with the control mechanism for alternative control services is to be demonstrated.

[1253] Integral Energy, emailed response to AER questions, 2 April 2009.
[1254] AER, *Draft decision*, p. 346.

In relation to assets constructed before 1 July 2009, compliance with the alternative control service control mechanism is to be demonstrated by the DNSPs providing the AER, as part of its pricing proposal, with the total annual charge it proposes to levy on each of its public lighting customers over the next regulatory year including an explanation of any adjustments.

The proposed charges for each customer should be consistent with the charges contained in this decision for the relevant regulatory year. However, if adjustments to charges have been made to account for changes in asset inventories in the previous regulatory year, these must be set out and explained in the pricing proposal. The pricing proposal should also include the revenues collected from each public lighting customer in the previous regulatory year.

In relation to assets constructed after 30 June 2009, compliance with the control mechanism is to be demonstrated by the DNSP through the publishing of the indexed tariff for the relevant regulatory year (with 2009–10 as the base year tariff as contained in this decision) at the same time as its general network tariffs are published.

The AER also requires the NSW DNSPs to provide their public lighting customers with an inventory list on at least a six monthly basis. This list should contain assets that have been added and removed from both the pre 1 July 2009 and post 30 June 2009 asset bases. The AER considers that this information could form part of the customer's bill, thereby allowing customers to verify the calculation of their charges.

As part of its annual compliance reporting, the AER will consider requiring the DNSPs to report public lighting performance information.

AER conclusion

In relation to assets constructed before 1 July 2009, compliance with the alternative control service control mechanism is to be demonstrated by providing the AER, as part of its pricing proposal, with the charges it proposes to levy on each of its public lighting customers over the next regulatory year, including an explanation of any adjustments.

In relation to assets constructed after 30 June 2009, compliance with the control mechanism is to be demonstrated by the DNSP through the publishing of the indexed tariff for the relevant regulatory year (with 2009–10 as the base year tariff as contained in this final decision) at the same time as its general network tariffs are published.

17.10 AER conclusions

Table 17.15 contains a summary of the the AER's decisions on key inputs and assumptions used to develop the prices and charges for each of the NSW DNSPs.

Table 17.15: AER decision on key inputs and assumptions

	Country Energy	EnergyAustralia	Integral Energy
Nominal vanilla WACC	8.78%	8.78%	8.83%
Pre–tax real WACC	6.76%	6.83%	6.88%
Forecast inflation	2.475%	2.475%	2.475%
Percentage of real labour escalation rate applied to maintenance charge	65%	65%	65%
Bulk lamp replacement rate	4 year BLR cycle to apply to 150W, 250W and 400W HPS, compact fluorescent and fluorescent lamps. 5 year BLR to twin arc lights 3 year BLR cycle to apply to all other lamps.	4 year BLRcycle to apply to 150W, 250W and 400W HPS, compact fluorescent and fluorescent lamps. 3 year BLR cycle to apply to all other lamps.	4 year BLR cycle to apply to 150W, 250W and 400W HPS, compact fluorescent and fluorescent lamps. 3 year BLR cycle to apply to all other lamps.
Cost of BLR under contract ($,2009–10)	–	33.64	–
Bulk replacements made per day	62.4	–	80
Spot replacements per day	18.5	25.33	25.33
Spot lamp failure rate	–	Under 3 year BLR: 70 W HPS - 9 % 100W HPS - 9 % 1000W HPS - 8 % Mercury Vapour - 2 % TF 2*20 - 11 % Under 4 year BLR: T5 - 2 % 150W HPS - 5 % 250W HPS - 5 % 400W HPS - 5 % 42 CFL - 5 %	–
Spot failure improvement rate under a 3 year bulk lamp replacement cycle	–	20%	–
Number of luminaires replaced in a day under a bulk luminaire regime	12	12	12
Design costs	Apply effective labour rate of $89.65 (including vehicle)	–	–
Overhead rate applied to plant/stores	30%	–	–
Overhead rate applied to materials and elevated work platform	30%	20%	–
Bracket Life[a]	35 years	35 years	35 years

(a) Applies to post 1 July 2009 charges only. Bracket life is 20 years for pre 1 July 2009 charges.

Table 17.16 sets out the forecast NSW EGW real labour growth rates used by the AER to model the NSW DNSPs' prices and charges.

Table 17.16: NSW EGW real labour growth rate (per cent)

	Country Energy	EnergyAustralia	Integral Energy
2007–08	1.38	2.73	–
2008–09	1.94	0.87	1.38
2009–10	2.54	3.35	3.35
2010–11	3.60	3.60	3.60
2011–12	2.40	2.40	2.40
2012–13	1.70	1.70	1.70
2013–14	0.60	0.60	0.60

17.11 AER decision

In accordance with clause 6.12.1(12) of the transitional chapter 6 rules, the control mechanism for Country Energy's alternative control services is:

- a schedule of fixed charges in the first year of the next regulatory control period for assets constructed before 1 July 2009 and a schedule of fixed prices in the first year of the next regulatory control period for assets constructed after 30 June 2009
- a price path for the remaining years of the next regulatory control period.

The schedule of fixed charges applicable to Country Energy for assets constructed before 1 July 2009 is contained in appendix P. The price path that has been applied to develop these charges is a straight-line smoothing which provides a fixed indexation rate for each year of the next regulatory control period.

The schedule of fixed prices for 2009–10 applicable to Country Energy for assets constructed after 30 June 2009 is contained in appendix R. The prices will be adjusted annually by the December quarter CPI data as published by the ABS.

In accordance with clause 6.12.1(12) of the transitional chapter 6 rules, the control mechanism for EnergyAustralia's alternative control services is:

- a schedule of fixed charges in the first year of the next regulatory control period for assets constructed before 1 July 2009 and a schedule of fixed prices in the first year of the next regulatory control period for assets constructed after 30 June 2009
- a price path for the remaining years of the next regulatory control period.

The schedule of fixed charges applicable to EnergyAustralia for assets constructed before 1 July 2009 is contained in appendix P. The price path that has been applied to develop these charges is a straight-line smoothing which provides a fixed indexation rate for each year of the next regulatory control period.

The schedule of fixed prices for 2009–10 applicable to EnergyAustralia for assets constructed after 30 June 2009 is contained in appendix R. The prices will be adjusted annually by the December quarter CPI data as published by the ABS.

In accordance with clause 6.12.1(12) of the transitional chapter 6 rules, the control mechanism for Integral Energy's alternative control services is:

- a schedule of fixed charges in the first year of the next regulatory control period for assets constructed before 1 July 2009 and a schedule of fixed prices in the first year of the next regulatory control period for assets constructed after 30 June 2009
- a price path for the remaining years of the next regulatory control period.

The schedule of fixed charges applicable to Integral Energy for assets constructed before 1 July 2009 is contained in appendix P. The price path that has been applied to develop these charges is a straight-line smoothing which provides a fixed indexation rate for each year of the next regulatory control period.

The schedule of fixed prices for 2009–10 applicable to Integral Energy for assets constructed after 30 June 2009 is contained in appendix R. The prices will be adjusted annually by the December quarter CPI data as published by the ABS.

In accordance with clause 6.12.1(12) of the transitional chapter 6 rules prior to a NSW DNSP introducing a new public lighting asset to its customers, the efficient capital and maintenance charges for the asset must be approved by the AER, in accordance with the process specified in section 17.8.2 of this final decision.

In accordance with clause 6.12.1(13) of the transitional chapter 6 rules the NSW DNSPs' compliance with the alternative control services control mechanism is to be demonstrated through annual approval of changes in the schedules of prices. The process for demonstrating compliance with the annual schedule of charges and prices is specified in section 17.9 of this final decision.

18 Pricing methodology for EnergyAustralia prescribed (transmission) standard control services

18.1 Introduction

This chapter sets out the AER's consideration of EnergyAustralia's revised proposed pricing methodology for the next regulatory control period, as submitted to the AER on 28 October 2008. There were no submissions received on this issue.

18.2 AER draft decision

The AER sought clarification of EnergyAustralia's cost allocation methodology outlined in its original proposed pricing methodology.[1255] EnergyAustralia made a number of minor adjustments and provided a revised proposed pricing methodology to the AER. The AER assessed EnergyAustralia's revised proposed pricing methodology against part J of the NER and the pricing methodology guidelines. Based on that assessment, the AER decided to approve EnergyAustralia's revised proposed pricing methodology.[1256]

18.3 Revised regulatory proposal

EnergyAustralia provided a formal signed copy of its approved pricing methodology in its revised regulatory proposal. EnergyAustralia noted that the pricing methodology attached to the draft decision was not the most current version and requested the AER provide clarification of the approved version in its final decision.

18.4 AER decision

In accordance with clause 6.12.1(20) of the transitional chapter 6 rules, EnergyAustralia's approved pricing methodology is set out in appendix T of this final decision.

[1255] AER, *Draft decision*, p. 350.
[1256] AER, *Draft decision*, p. 357.

Glossary

AASB	Australian Accounting Standards Board
ABS	Australian Bureau of Statistics
ACG	Allen Consulting Group
AMS	Asset Management System
Anglicare	Anglicare Sydney
ANZ	Australia and New Zealand Banking Group Limited
ANZSIC	Australian New Zealand Standard Industrial Classification
AR	allowed revenue
AS	Australian standard
ASP	accredited service provider (a person who has been accredited under Part 10 Electricity Supply (General) Regulation 2001 (NSW))
AUD	Australian Dollar
bppa	basis points per annum
CAPM	capital asset pricing model
CASA	Civil Aviation Safety Authority
CBD	central business district
CEG	Competition Economists Group
CFC	Construction Forecasting Council
CGS	Commonwealth government securities
CIE	Centre for International Economics
CIS	customer information system
CPRS	Carbon Pollution Reduction Scheme
DEUS	NSW Department of Energy, Utilities and Sustainability (now DWE)
DMIA	demand management innovation allowance
DMIS	demand management incentive scheme
DRP	dividend reinvestment plan
DUOS	distribution use of system
DWE	NSW Department of Water and Energy
EAPA	energy accounts payment assistance
EBA	enterprise bargaining agreement
EBSS	efficiency benefit sharing scheme
EGW	electricity, gas and water
EMA	Emergency Management Australia
EMRF	Energy Markets Reform Forum

EMS	Energy and Management Services Pty Ltd
ESCV	Essential Services Commission of Victoria
ESIPC	Electricity Supply Industry Planning Council
ESRA	electrical safety rules allowance
EUAA	Energy Users Association of Australia
Excluded distribution service rule	Rule to which unregulated distribution services are subject, available in: IPART, Final Report: NSW Electricity Distribution Pricing, 2. Regulation of Excluded Distribution Services Rule 2004, June 2004, Appendix 2
GIS	geographic information systems
GSL	guaranteed service levels
GSP	gross state product
GWh	giga watt hour
HPS	high pressure sodium
HRC	hot rolled coil
Huegin	Huegin Consulting Group
HV	high voltage
IEEE	Institute of Electrical and Electronic Engineers
JIA	Joint Industry Association
KPMG	KPMG Australia
kW	kilo watt
kWh	kilo watt hour
LCM	labour cost model
LME	London Metal Exchange
MAIFI	momentary average interruption frequency index
MAR	maximum allowed revenue
MCE	Ministerial Council on Energy
MM	miscellaneous and monopoly services
MM2	Murphy model 2
MMA	McLennan Magasanik Associates
MRP	market risk premium
MSATS	market settlement and transfer system operated by NEMMCO
MW	mega watt
MWh	mega watt hour
NAB	National Australia Bank
NCC	negotiable component criteria
NDSC	negotiated distribution service criteria
NEL	National Electricity Law

NEM	national electricity market
NERA	NERA Economic Consulting
NIEIR	National Institute of Economic and Industry Research
NMI	national metering identifier
NPV	net present value
NSP	network service provider
NTER	National tax equivalence regime
NUOS	network use of system
NYMEX	New York Mercantile Exchange
OH	overhead
original DMIA	the DMIA applied by the AER in: AER, *Final Decision: Demand management incentives schemes for the ACT and NSW 2009 distribution determinations*, Canberra, February 2008.
PIAC	Public Interest Advocacy Centre
POE	probability of exceedence
PPI	producer price indices
PTRM	post–tax revenue model
Public Lighting Code	DEUS voluntary code of practice for a range of public lighting services in NSW
RAB	regulatory asset base
RBA	Reserve Bank of Australia
replacement DMIA	the DMIA published in November 2008: AER, Demand management incentive scheme for the ACT and NSW 2009 distribution determinations – Demand management innovation allowance scheme, November 2008.
REROC	Riverina Eastern Regional Organisation of Councils
RFM	roll forward model
RIO	regulation information order
S&P	Standard and Poor’s
SAHA	SAHA International Limited
SAIDI	system average interruption duration index
SEO	seasoned equity offer
SFG	Strategic Finance Group
Sheather decision	Sheather v Country Energy [2007] NSWCA 179 (24 July 2007)
SKM	Sinclair Knight Merz Pty Ltd
SRP	ACCC, *Statement of principles for the regulation of electricity transmission revenues*, 8 December 2004
SSROC	South Sydney Regional Organisation of Councils

standard control services guideline	AER, *Final decision: Control mechanisms for direct control services for the ACT and NSW 2009 distribution determinations*, February 2008
Statement on alternative control services	AER, *Statement on alternative control services for the ACT and NSW 2009 distribution determinations*, February 2008
STPIS	service target performance incentive scheme
Sylvania Lighting	Sylvania Lighting Pty Ltd
TEC	Total Environment Centre
the IPART control mechanism	the control mechanism determined by IPART for the corresponding prescribed distribution services in the current regulatory control period
TNSP	transmission network service provider
ToU	Time of Use
TTEG	Trans Tasman Energy Group
TUOS	transmission use of system
UG	underground
Ofgem	Office of Gas and Electricity Markets – UK regulator
USD	United States Dollar
WACC	weighted average cost of capital
WAPC	weighted average price cap
WSROC	Western Sydney Regional Organisation of Councils
YTM	yield to maturity

Appendix A: Assigning customers to tariff classes

Procedures for assigning or reassigning customers to tariff classes

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

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

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

2. If, after 1 July 2009, a NSW DNSP becomes aware that a person will become a customer of the DNSP, then the DNSP must determine the tariff class to which the new customer will be assigned.
3. In determining the tariff class to which a customer or potential customer will be assigned, or reassigned, in accordance with section 2 or 5, a DNSP must take into account one or more of the following factors:
   (a) the nature and extent of the customer's usage
   (b) the nature of the customer's connection to the network[1257]
   (c) whether remotely–read interval metering or other similar metering technology has been installed at the customer's premises as a result of a regulatory obligation or requirement.
4. In addition to the requirements under section 3, a NSW DNSP, when assigning or reassigning a customer to a tariff class, must ensure the following:
   (a) that customers with similar connection and usage profiles are treated equally
   (b) that customers which have micro–generation facilities are not treated less favourably than customers with similar load profiles without such facilities.

Reassignment of existing customers to another existing or a new tariff during the next regulatory control period

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

[1257] The AER interprets 'connection' to include the installation of any technology capable of supporting timed based tariffs.

Objections to proposed assignments and reassignments

6. A NSW DNSP must notify the customer concerned in writing of the tariff class to which the customer has been assigned or reassigned by the DNSP, prior to the assignment or reassignment occurring. If the DNSP does not know the identity of the customer then it must notify the customer's retailer instead. The notice must include advice that the customer may request further information from the DNSP, may object to the proposed assignment or reassignment and, if the customer objects to the proposed assignment or reassignment and that objection is not resolved to the satisfaction of the customer, the customer may request the Energy & Water Ombudsman NSW (provided the customer is a small retail customer[1258]) to decide which of the DNSP's tariff classes the customer should be assigned to. If the customer is not a small retail customer then the customer must be notified of the type of alternative dispute resolution which is available to the customer.

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

8. If, in response to a notice issued in accordance with section 6, a customer makes an objection to the relevant NSW DNSP about the proposed assignment or reassignment, the relevant NSW DNSP must reconsider the proposed assignment or reassignment, taking into consideration the factors in sections 3 and 4 above, and notify the customer in writing of its decision and the reasons for that decision.

9. If a customer's objection to a tariff assignment or reassignment is upheld by the Energy & Water Ombudsman NSW or through some other form of alternative dispute resolution, then any adjustment which needs to be made to prices will be done by the relevant NSW DNSP as part of the next annual review of prices.

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

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

11. If the AER considers that the method provided under section 10 does not provide for an effective system of assessment and review of the basis on which a customer is charged, the AER may request additional information or request that the relevant NSW DNSP revise and resubmit a revised method.

12. If the AER considers the method provided in accordance with section 10 is reasonable it will approve that method by notice in writing to the relevant NSW DNSP.

[1258] The expression 'small retail customer' is defined in section 92(1) of the *Electricity Supply Act 1995 (NSW)*.

Appendix B: Negotiable component criteria

National Electricity Objective

1. The terms and conditions of access for a negotiable component of a direct control service, including the price that is to be charged for the negotiable component and any access charges, should promote the achievement of the national electricity objective.

Criteria for terms and conditions of access

Terms and conditions of access

2. The terms and conditions of access for a negotiable component must be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER.
3. The terms and conditions of access for a negotiable component (including, in particular, any exclusions and limitations of liability and indemnities) must not be unreasonably onerous taking into account the allocation of risk between the DNSP and the other party, the price for the negotiable component and the costs to the DNSP of providing the negotiable component.
4. The terms and conditions of access for a negotiable component must take into account the need for the direct control service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER.

Price of Services

5. The price for a negotiable component must be the price for that component in the DNSP's approved pricing proposal, unless the terms and conditions sought for the component are so different from those used for the purposes of establishing the approved pricing proposal as to warrant determination of the price without regard to this criterion.
6. Subject to criterion 5, the price for a negotiable component must reflect the costs that the DNSP has incurred or incurs in providing that component, and must be determined in accordance with the principles and policies set out in the Cost Allocation Method.
7. Subject to criteria 5, 8 and 9, the price for a negotiable component must be at least equal to the cost that would be avoided by not providing it but no more than the cost of providing it on a stand alone basis.
8. Subject to criterion 5, if the direct control service of which the negotiable component is a component is the provision of a shared distribution service that:

   i. exceeds any network performance requirements which it is required to meet under any relevant electricity legislation; or

   ii. exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER, then the difference between the price for that direct control service and the price for the shared distribution service which meets network performance requirements must reflect the DNSP's incremental cost of providing that service (as appropriate).

9. Subject to criterion 5, if the direct control service of which the negotiable component is a component is the provision of a shared distribution service that does not meet or exceed the network performance requirements, the difference between the price for that service and the price for the shared distribution service which meets, but does not exceed, the network performance requirements should reflect the cost the DNSP would avoid by not providing that service (as appropriate).
10. Subject to criterion 5, the price for a negotiable component must be the same for all Distribution Network Users unless there is a material difference in the costs of providing the negotiable component to different Distribution Network Users or classes of Distribution Network Users.
11. Subject to criterion 5, the price for a negotiable component must be subject to adjustment over time to the extent that the assets used to provide the direct control service are subsequently used to provide services to another person, in which case such adjustment must reflect the extent to which the costs of those assets are being recovered through charges to that other person.
12. Subject to criterion 5, the price for a negotiable component must be such as to enable the DNSP to recover the efficient costs of complying with all regulatory obligations or requirements associated with the provision of the negotiable component.

Criteria for access charges

Access Charges

13. Any access charges must be based on costs reasonably incurred by the DNSP in providing distribution network user access and, in the case of compensation referred to in clause 5.5(f)(4)(ii) to (iii) of the NER, on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to in those provisions where an event referred to in those provisions occurs (as appropriate).

Appendix C: EnergyAustralia negotiated distribution service criteria

National Electricity Objective

1. The terms and conditions of access for an EnergyAustralia negotiated distribution service, including the price that is to be charged for the provision of that service and any access charges, should promote the achievement of the national electricity objective.

Criteria for terms and conditions of access

Terms and Conditions of Access

2. The terms and conditions of access for an EnergyAustralia negotiated distribution service must be fair and reasonable and consistent with the safe and reliable operation of the power system in accordance with the NER.
3. The terms and conditions of access for an EnergyAustralia negotiated distribution service (including, in particular, any exclusions and limitations of liability and indemnities) must not be unreasonably onerous taking into account the allocation of risk between EnergyAustralia and the other party, the price for the negotiated distribution service and the costs to EnergyAustralia of providing the negotiated distribution service.
4. The terms and conditions of access for an EnergyAustralia negotiated distribution service must take into account the need for the service to be provided in a manner that does not adversely affect the safe and reliable operation of the power system in accordance with the NER.

Price of Services

5. The price for an EnergyAustralia negotiated distribution service must reflect the costs that EnergyAustralia has incurred or incurs in providing that service, and must be determined in accordance with the principles and policies set out in the Cost Allocation Method.
6. Subject to criteria 7 and 8, the price for an EnergyAustralia negotiated distribution service must be at least equal to the cost that would be avoided by not providing that service but no more than the cost of providing it on a stand alone basis.
7. If an EnergyAustralia negotiated distribution service is a shared distribution service that:

   i. exceeds any network performance requirements which it is required to meet under any relevant electricity legislation; or

   ii. exceeds the network performance requirements set out in schedule 5.1a and 5.1 of the NER,

   then the difference between the price for that service and the price for the shared distribution service which meets network performance requirements must reflect EnergyAustralia's incremental cost of providing that service (as appropriate).

8. If an EnergyAustralia negotiated distribution service is the provision of a shared distribution service that does not meet or exceed the network performance requirements, the difference between the price for that service and the price for the shared distribution service which meets, but does not exceed, the network performance requirements should reflect the cost EnergyAustralia would avoid by not providing that service (as appropriate).
9. The price for an EnergyAustralia negotiated distribution service must be the same for all Distribution Network Users unless there is a material difference in the costs of providing the negotiated distribution service to different Distribution Network Users or classes of Distribution Network Users.
10. The price for an EnergyAustralia negotiated distribution service must be subject to adjustment over time to the extent that the assets used to provide that service are subsequently used to provide services to another person, in which case such adjustment must reflect the extent to which the costs of that asset are being recovered through charges to that other person.
11. The price for an EnergyAustralia negotiated distribution service must be such as to enable EnergyAustralia to recover the efficient costs of complying with all regulatory obligations or requirements associated with the provision of the negotiated distribution service.

Criteria for access charges

Access Charges

12. Any access charges must be based on costs reasonably incurred by EnergyAustralia in providing distribution network user access and, in the case of compensation referred to in clauses 5.4A(h) to (j) of the NER, on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to in those provisions where an event referred to in those provisions occurs (as appropriate).

Appendix D: Country Energy negotiating framework

Country Energy Negotiating Framework

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MCS/Revised Negotiating Framework 131106.DOC

Country Energy Negotiating Framework for Negotiable Components

1. Introduction

1.1 Purpose of this Negotiating Framework

This document sets out the minimum requirements to be followed during negotiations between Country Energy and any person (***Service Applicant***) who wishes to receive a *direct control service* from Country Energy for the purpose of the *2009 regulatory control period* that is determined by the AER to have one or more components that are negotiable components under clause 6.7A(a) of the Rules.

1.2 What is a "negotiable component"?

A negotiable component may be a particular component of a *direct control service* provided by Country Energy or may relate to the terms or conditions on which a *direct control service* or a component of a *direct control service* is to be provided by Country Energy.

A *direct control service* is a *distribution service* that is a direct control network service within the meaning of section 2B of the National Electricity Law.

1.3 *Contestable* Services

Contestable services are not covered by this Negotiating Framework. They are services which, under New South Wales law, can be provided by more than one Accredited Service Provider as a contestable service or on a competitive basis.

1.4 Terms and condition of access

The *terms and condition of access* for a negotiable component:

(1) are to be fair and reasonable and consistent with the safe and reliable operation of the *power system* in accordance with the Rules and the process for negotiable components. The price for a negotiable component is to be treated as being fair and reasonable where it complies with the principles in 6.7A.1(1)-(8);

(2) must not be unreasonably onerous taking into account the allocation of risk and the cost of providing the negotiable component; and

(3) should take into account the need for the *direct control service* to be provided in a manner that does not adversely affect the *power system*.

2. Charges

2.1 Any *access charges* to be imposed by Country Energy will be based on the costs reasonably incurred in providing *distribution network user access*, and in the case of compensation referred to in clause 5.5(f)(4)(ii) and (iii), on the revenue that is likely to be foregone and the costs that are likely to be incurred by a person referred to those provisions where an event in those provisions occurs.

3. Basis for Negotiation

3.1 Country Energy to comply with Negotiating Framework

Country Energy will comply with this Negotiating Framework when negotiating with *Service Applicants* in relation to a negotiable component in accordance with its obligations under the Rules.

3.2 *Service Applicant* to comply with Negotiating Framework

Service Applicants are required by the Rules to comply with this Negotiating Framework when negotiating with Country Energy in relation to a negotiable component.

3.3 Good Faith Negotiations

Country Energy and each *Service Applicant* that initiates a negotiation under this Negotiating Framework agree to conduct that negotiation in good faith.

3.4 Authority

(1) A *Service Applicant* that initiates a negotiation under this Negotiating Framework must nominate a person that has authority to represent the *Service Applicant* in the negotiations and provide Country Energy with contact details for that person. If the *Service Applicant* comprises more than one entity (e.g. a partnership or joint venture) the nominated person must have authority to represent all of the relevant entities.

(2) Country Energy will, in respect of each negotiation initiated under this Negotiating Framework, nominate a person that has authority to represent Country Energy in the negotiations and provide the *Service Applicant* with contact details for that person.

4. Connection to Country Energy's Network

4.1 This Negotiating Framework does not replace the process set out in the *Rules* for making an application to establish or modify a *connection*. However, in some cases the negotiations to which this Negotiating Framework applies may occur in the context of such an application.

4.2 The process for establishing or modifying a connection is set out in clause 5.3 of the *Rules* and comprises five basic steps:

(1) a *connection* enquiry made by the *Connection Applicant*;

(2) the initial response by the *Local Network Service Provider*;

(3) a *connection* application made by the *Connection Applicant*;

(4) an offer made by the *Local Network Service Provider*; and

(5) finalisation of a *connection agreement* between the *Connection Applicant* and *Local Network Service Provider*.

4.3 Country Energy envisages that a *Connection Applicant* would identify any negotiation it wished to conduct under this Negotiating Framework as part of its *connection* enquiry and initiate the process for any such negotiation at the stage of making a connection application. The offer to be made by Country Energy pursuant to clause 5.3.6 of the Rules to a *Connection Applicant* would then include the preliminary offer to be made as part of this Negotiating Framework, and the agreement to be entered into by the parties under clause 5.3.7 of the Rules would reflect the outcome negotiated pursuant to this Negotiating Framework.

4.4 Country Energy's document "Customer Funded Connections & Connection Related Services" is located on Country Energy's website at: http://www.countryenergy.com.au/internet/cewebpub.nsf/AttachmentsByTitle/Customer_Funded_Connections_July_2007.pdf/$FILE/Customer_Funded_Connections_July_2007.pdf. The document contains Country Energy's general conditions for customer funded services which include customer connection services, connection works and customer funded network augmentations.

4.5 When Country Energy is providing a *Service Applicant* a preliminary response under section 5.2 of this Framework, Country Energy will, if appropriate, provide the *Service Applicant* with a copy of Country Energy's Agreement in Relation to Connection Investigation (**Agreement**).

4.6 The Agreement relates to the services Country Energy provides to a *Service Applicant* as part of the connection application process.

4.7 Country Energy is not required to take any further action under this Negotiating Framework until the *Service Applicant* has executed the Agreement.

5. Process for Negotiation

5.1 Initiation of process by *Service Applicant*

(1) The process set out in this Negotiating Framework will be initiated when a *Service Applicant*, having lodged a Rules compliant *connection* enquiry with Country Energy, provides a written request to Country Energy to conduct a negotiation under this Negotiating Framework.

(2) The request must identify the type, magnitude and timing of the proposed *connection* to Country Energy's *network*.

5.2 Preliminary response and request for information by Country Energy

(1) When Country Energy receives a written request from a *Service Applicant* to conduct a negotiation under this Negotiating Framework, Country Energy will provide a preliminary response to the *Service Applicant*. The preliminary response will include:

(a) a list of the information that Country Energy would like the *Service Applicant* to provide to Country Energy for the purpose of the negotiation. The nature of the information that Country Energy may request the *Service Applicant* to provide is described in section 6.2 of this Negotiating Framework and includes the information the *Service Applicant* is required to provide under the relevant schedules in chapter 5 of the Rules;

(b) an estimate of the fees that Country Energy is entitled to charge pursuant to the Rules to cover its reasonable direct expenses of processing the request (which may include the cost of providing information under section 6.1 of this Negotiating Framework) and the date the fees must be paid. Country Energy may provide the *Service Applicant* with revised estimates of the fee from time to time;

(c) if appropriate, a copy of Country Energy's standard Agreement; and

(d) where negotiations relate to a *connection* application, a copy of Country Energy's standard form negotiated *connection agreement*.

(2) Country Energy will provide this preliminary response to the *Service Applicant* in writing and will use its reasonable endeavours to do so within 10 business days of receiving the initial written request from the *Service Applicant*.

5.3 Request for information by Service Applicant

(1) The *Service Applicant* must provide Country Energy with a written request for, and a list of, the information that the *Service Applicant* would like Country Energy to provide to the *Service Applicant* for the purpose of the negotiation. The nature of the information that the *Service Applicant* may request Country Energy to provide is described in section 6.1 below.

(2) The *Service Applicant* must use its reasonable endeavours to provide this information request within 20 business days of receiving the preliminary response from Country Energy.

6. Exchange of information

6.1 Provision of information by Country Energy

(1) Country Energy must provide all such commercial information as the *Service Applicant* may reasonably require to enable the *Service Applicant* to engage in effective negotiation with Country Energy for the provision of the negotiable component.

(2) Country Energy must:

(a) identify and inform the *Service Applicant* of the reasonable costs and/or the cost increase or decrease in costs (as appropriate) of providing the negotiable component; and

(b) demonstrate to the *Service Applicant* that its charges for providing those negotiable components reflect those costs and/or the cost increment or decrement (as appropriate); and

(c) have appropriate arrangements for assessment and review of the charges and the basis on which they are made.

(3) To the extent possible, Country Energy must provide the information in writing to the *Service Applicant*.

(4) Country Energy will use its reasonable endeavours to provide the information within 20 business days of the later of the following dates:

(a) the date on which Country Energy receives the information request from the *Service Applicant*; or

(b) the date on which the *Service Applicant* executes the Agreement.

(5) If Country Energy believes that the timeframe set out in section 6.1(4) is not an achievable timeframe, the parties must negotiate in good faith to agree an achievable timeframe.

6.2 Provision of information by the *Service Applicant*

(1) The *Service Applicant* must provide all such commercial information as Country Energy may reasonably require to enable Country Energy to engage in effective negotiation with the *Service Applicant* for the provision of a negotiable component.

(2) To the extent possible, the *Service Applicant* must provide the information in writing to Country Energy.

(3) The *Service Applicant* must use its reasonable endeavours to provide the information within 20 business days of receiving the preliminary response from Country Energy.

(4) If the *Service Applicant* believes that the timeframe set out in section 6.2(3) is not an achievable timeframe, the parties must negotiate in good faith to agree an achievable timeframe.

6.3 Additional information or clarification

(1) Either party may request additional information from, or clarification of information that has been provided by, the other party.

(2) The parties will negotiate in good faith to provide this additional information or clarification to the other party within a reasonable timeframe.

7. Other Distribution Network Users

7.1 Country Energy must determine the potential impact on other *Distribution Network Users* of the provision of the negotiable component to the *Service Applicant.*

7.2 Country Energy must notify and consult with any affected *Distribution Network Users* and ensure that the provision of these negotiable components does not result in non-compliance with obligations in relation to other *Distribution Network Users* under the Rules.

7.3 Country Energy will start any relevant consultation process as soon as it has received sufficient information from the *Service Applicant* to enable it to proceed. Country Energy will use its reasonable endeavours to progress and complete the consultation process at the earliest practicable date.

7.4 Country Energy will keep the *Service Applicant* under this Negotiating Framework informed of the progress of any such consultation process.

8. Application for Connection

8.1 The *Service Applicant* will provide Country Energy with an *application to connect* in accordance with clauses 5.3.4 and 5.3.4A of the Rules.

8.2 Country Energy may refuse to accept an *application to connect* from the *Service Applicant* unless it is provided in accordance with clauses 5.3.4 and 5.3.4A of the Rules.

9. Offer and Negotiating Timetable

9.1 Offer

(1) Country Energy will undertake an initial assessment of the request and the information provided by the *Service Applicant* under sections 6.2 and 8.1 and advise the *Service Applicant* in writing of Country Energy's expected timeframe for making an offer.

(2) Country Energy will use its reasonable endeavours to provide an offer (in writing) within the notified timeframe, or in any event within 120 business days from its receipt of a written request from the *Service Applicant* to negotiate under this Negotiating Framework.

9.2 Negotiating Timetable

(1) Once Country Energy has provided an offer to the *Service Applicant*, Country Energy and the *Service Applicant* must hold an initial meeting to discuss that offer and, if necessary, the timetable for conducting negotiations in relation to that offer.

(2) The parties must use their reasonable endeavours to hold the initial meeting within 10 business days of the *Service Applicant* receiving the offer from Country Energy.

(3) If desired by either Country Energy or the *Service Applicant*, the parties must seek to establish a timetable for meetings and responses with a view to entering into a *connection agreement* within a reasonable period which is acceptable to each of them.

(4) Unless otherwise negotiated and agreed by the parties under section 9.2(3) the parties will use their reasonable endeavours to finalise negotiations within 160 business days from the date Country Energy receives a written request from the *Service Applicant* to negotiate under this negotiating Framework.

9.3 Negotiation

Each of Country Energy and the *Service Applicant* must use its reasonable endeavours to adhere to the timetable established for the negotiation (if any) and to progress the negotiation expeditiously and in good faith.

9.4 Indicative timetable

Unless otherwise negotiated and agreed by the parties, Country Energy proposes a timeframe for progressing and finalising negotiations for the provision of negotiable components at Table 1, Attachment 1. This timetable may be adopted or modified by agreement of the parties.

10. Confidential Information

10.1 For the avoidance of doubt, commercial information which is required to be provided by Country Energy to a *Service Applicant* in accordance with clause 6.1(1):

(1) does not include *confidential information* provided to Country Energy by another person; and

(2) may be provided subject to a condition that the *Service Applicant* must not provide any part of that commercial information to any other person without the consent of Country Energy.

10.2 For the avoidance of doubt, commercial information which is required to be provided by a *Service Applicant* to Country Energy in accordance with clause 6.2(1):

(1) does not include *confidential information* provided to the *Service Applicant* by another person; and

(2) may be provided subject to a condition that Country Energy must not provide any part of that commercial information to any other person without the consent of the relevant *Service Applicant*.

11. Dispute Resolution

11.1 Any disputes between Country Energy and the *Service Applicant* as to the *terms and conditions of access* for the provision of a negotiable component are to be dealt with in accordance with relevant provisions of the National Electricity Law and the *Rules* for dispute resolution.

12. Publication

12.1 Country Energy will publish the outcome of the negotiation to provide negotiable components on its website.

13. Costs

13.1 The *Service Applicant* must pay Country Energy's reasonable direct expenses incurred in processing the application to provide a negotiable component.

14. Termination of Negotiation

14.1 *Service Applicant* may terminate negotiation

(1) A *Service Applicant* that has initiated a negotiation under this Negotiating Framework may, at any stage, elect not to continue with the negotiation.

(2) The *Service Applicant* must confirm its decision to terminate a negotiation in writing to Country Energy as soon as practicable after electing not to continue with the negotiation.

14.2 Country Energy may terminate negotiation

(1) Country Energy may terminate a negotiation under this Negotiation Framework where:

(a) either party has exercised its rights to terminate the Agreement;

(b) Country Energy believes, on reasonable grounds, that the *Service Applicant* is not conducting the negotiation under this Negotiation Framework in good faith;

(c) the *Service Applicant* consistently fails to comply with the requirements of this Negotiation Framework; or

(d) the *Service Applicant* has failed to comply with an obligation in this Negotiation Framework to use its reasonable endeavours to undertake or complete an action within a specified or agreed timeframe, and does not complete the relevant action within 20 business days of a written request from Country Energy.

(2) Country Energy must inform the *Service Applicant* in writing of its decision to terminate a negotiation.

15. Agreement reached as a result of negotiation

15.1 If the parties reach an agreed position as a result of a negotiation under this Negotiation Framework, that *connection agreement* will not take effect until it is recorded in writing and signed by both parties.

16. Interpretation of this Negotiating Framework

16.1 Defined Terms

(1) The references in this Negotiating Framework to the "National Electricity Rules" or the "Rules" are references to the "Rules" as defined in the National Electricity (New South Wales) Act 1997.

(2) Terms in italic have the same meaning given to them by the Rules.

(3) A word or phrase defined in the Agreement in Relation to Connection Investigation (**Agreement**) has the same meaning in this Negotiating Framework.

16.2 Rules of Interpretation

The rules of interpretation set out in the Agreement apply to this Negotiating Framework.

16.3 Departures from this Negotiation Framework

(1) Subject to the parties' obligations under the Rules, the parties may agree to depart from any specific aspect of this Negotiation Framework.

(2) Any such agreement must be recorded in writing and signed by both parties and must identify which aspect of the Negotiation Framework the parties are departing from and which aspects continue to apply.

(3) In the event of any inconsistency between this Negotiating Framework and any of the requirements of Rules 5.3 and 5.5 and other relevant provisions of Chapter 6 of the Rules, those requirements prevail.

17. Notices

17.1 All communication provided in writing by a *Service Applicant* pursuant to this Negotiating Framework must be delivered to P.O. Box 718, Queanbeyan, News South Wales, 2620 unless the Applicant is otherwise directed by Country Energy.

Attachment 1

Table 1 provides an indicative timeframe for provision of information, negotiation and finalisation of negotiations for a negotiable component. Country Energy and the *Service Applicant* must use all reasonable endeavours to adhere to this timetable unless otherwise agreed between the parties.

Table 1

	Event	Indicative timeframe
Receipt date	*Service Applicant* provides a written request to conduct a negotiation under this Framework	
Preliminary response	Country Energy to provide a preliminary response to the *Service Applicant*	Receipt date + 10 business days
Service Applicant request	*Service Applicant* to provide a request for information to Country Energy for the purpose of this negotiation	Preliminary response + 20 business days
Country Energy response	Country Energy to provide information to the *Service Applicant* on costs, charges and review arrangements, and all other information required for negotiation	20 business days from the later of: (i) *Service Applicant* request; or (ii) execution of Agreement.
Negotiation information	*Service Applicant* to provide Country Energy with all commerical information required for effective negotiation	Preliminary response + 20 business days
Offer	Offer to be sent by Country Energy to the *Service Applicant*	Receipt date + 120 business days
Initial meeting	Parties to hold an initial meeting and establish a timetable for conducting negotiations	Offer + 10 business days
Final agreement	Parties to finalise agreement	Receipt date + 160 business days

Appendix E: EnergyAustralia negotiating framework

ATTACHMENT 5.1

Proposed Negotiating Framework for Negotiated Distribution Services AND Negotiable Components of Direct Control Services
1 July 2009 to 20 June 2014

June 2008

REVIEW

Responsibility	Name	Date
Author	J Smith	22 May 2008
Reviewer		

Approval	Name	Signature	Date
EM-NR&P	H. Colebourn		22 May 2008

Background

A. The Transitional Rules set out in Chapter 11 and Appendix 1 to the National Electricity Rules (the Transitional Rules") provide that:

(a) EnergyAustralia must prepare a document setting out the procedure to be followed during negotiations between it and any person who wishes to receive a Negotiated Distribution Service as to the terms and conditions of access for the provision of the service (Transitional Rules Part D Clause 6.7.5(a));

(b) A Distribution Network Service Provider must prepare a document setting out the procedure to be followed during negotiations between it and any person who wishes to be provided with a negotiable component of a direct control service as to the terms and conditions of access for the provision of the service (Transitional Rules Part DA Clause 6.7.5(a));

(c) the negotiating frameworks required by the Transitional Rules must comply with and be consistent with the applicable requirements of a distribution determination applying to the provider; and

(d) the negotiating frameworks must comply with and be consistent with the

applicable requirements of Part D clause 6.7.5(c) and Part DA clause 6.7A.5(c), which sets out the minimum requirements for a negotiating framework.

(e) EnergyAustralia may prepare and submit a document that combines both negotiating frameworks into a single framework (Part DA clause 6.7.A5(f)).

B. This document has been prepared in fulfilment of EnergyAustralia's obligations under Transitional Rules Part D Clause 6.7.5(a) and Part DA Clause 6.7A.5(a) to establish negotiating frameworks.

C. This document applies to EnergyAustralia and any Service Applicant who applies to receive a Negotiated Distribution Service or a negotiable component of a direct control service.

D. As at 2 June 2008 an EnergyAustralia Negotiated Distribution Service is a service that is provided by EnergyAustralia by means of, or in connection with, the EnergyAustralia transmission support network and that would otherwise be classified as a negotiated transmission service (Transitional Rules 6.1.6(d)).

E. As at 1 July 2009 a Negotiable Component of a Direct Control Service is a component of a direct control service that is provided by EnergyAustralia and that has been determined by the AER to be a negotiable component of a direct control service under a distribution determination.

EnergyAustralia's Negotiating Framework

1 Application of negotiating framework

1.1 This negotiating framework applies to EnergyAustralia and each Service Applicant who has made an application in writing to EnergyAustralia for the provision of either a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service.

1.2 EnergyAustralia and any Service Applicant who wishes to receive a Negotiated Distribution Service or a Negotiable Component of a Direct Control S ervice from EnergyAustralia must comply with the requirements of this negotiating framework.

1.3 The requirements set out in this negotiating framework are additional to any requirements or obligations contained in Clauses 5.3, 5.4A and 5.5 and Chapter 6A of the National Electricity Rules (NER) or in the Transitional Rules. In the event of any inconsistency between this negotiating framework and any other requirements in the NER, the requirements of the NER will prevail.

1.4 Nothing in this negotiating framework or in the NER will be taken as imposing an obligation on EnergyAustralia to provide any service to the Service Applica nt.

2 Obligation to negotiate in good faith

2.1 EnergyAustralia and the Service Applicant must negotiate in good faith the terms and conditions of access for the provision by EnergyAustralia of the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service sought by the Service Applicant.

3 Timeframe for commencing, progressing and finalising negotiations

3.1 Clause 3.4 and Table 1 set out the timeframe for commencing, progressing and finalising negotiations in relation to applicat ions for a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service.

3.2 The timeframe set out in Table 1 will not apply where a timeframe is specified in Chapter 5 in relation to any application for negotiated distribution serv ices, and in that case the time period specified in Chapter 5 will apply.

3.3 The timeframe set out in clause 3.4 may be suspended in accordance with clause 9.

3.4 Timeframes:

(a) The specified time for commencing, progressing and finalising negotiations with a Service Applicant is as set out in Table 1.

(b) EnergyAustralia and the Service Applicant shall use reasonable endeavours to adhere to the time periods specified in Table 1 and may by agreement extend any such time period.

(c) The preliminary program finalised u nder C in Table 1 may be modified from time to time by agreement of the parties, where such agreement must not be unreasonably withheld. Any such amendment to the preliminary program shall be taken to be a reasonable period of time for commencing, progress ing and finalising negotiations with a Service Applicant for the provision of the Negotiated Distribution Service or the Negotiable Component of a Standard Control Service. The requirement in (clause 3.3(b) applies to the last amended preliminary program.

Table 1

	Event	Indicative timeframe
A.	Receipt of written application for a Negotiated Distribution Service or Negotiable Component of a direct control service. The application must be made by either: Completing an Application Form in accordance with EnergyAustralia publications *ES 1-Customer Connection Information* or *ES 10-Requirements for Electricity Connections to Developments* (where the service requested relates to services provided under EnergyAustralia's Standard Form Customer Connection Contract) or Making a connection inquiry, where an application is being made to establish or modify a connection under Chapter 5 of the National Electricity Rules	X
B.	Parties meet to discuss a preliminary negotiation programme with milestones that represent a reasonable period of time for commencing, progressing and finalising negotiations.	X + 15 business days
C.	Parties finalise negotiation programme, which may include, without limitation, milestones relating to: ▪ the provision of information by Energy Australia to meet the obligation in clause 5.1. ▪ the request and provision of commercial information by EnergyAustralia and the Service Applicant, see clauses 4 and 5; and ▪ notification and consultation with any affected Distribution Network Users, see clause 6. ▪ The Negotiable Component or Negotiable Distribution Service being formally specified by the Service Applicant ▪ The notification by EnergyAustralia of its reasonable direct expenses incurred in processing the application and the payment of those expenses by the service applicant, see clause 9.	X + 30 business days
D	Parties progress negotiations and the Service Applicant specifies to EnergyAustralia the exact Negotiable Distribution Service or Negotiable Component of a direct control service which is required to be provided.	X + 40 business days
E	Parties finalise negotiations	X + 60 business days or (where the reasonable direct expenses of EnergyAustralia have been requested but not paid by the service applicant) within 20 business days of those expenses being paid to EnergyAustralia.

4 Provision of Commercial Information by Service Applicant

4.1 EnergyAustralia may give notice to the Service Applicant requesting Commercial Information held by the Service Applicant that is reasonably required by EnergyAustralia to enable it to engage in effective negotiations with the Service Applicant in relation to the application and to enable EnergyAustralia to submit Commercial Information to the Service Applicant.

4.2 Subject to clauses 4.3 and 4.4, the Service Applicant must use its reasonable endeavours to provide EnergyAustralia with the Commercial Information requested by EnergyAustralia in accordance with clause 4.1 within 10 Business Days of that request, or within a time period as agreed by the parties.

4.3 Confidentiality Requirements - Commercial Information

4.4 For the purposes of this clause 4, Commercial Information does not include:

(a) confidential information provided to the Service Applicant by another person; or

(b) information that the Service Applicant is prohibited, by law, from disclosing to EnergyAustralia.

4.5 Commercial Information may be provided by the Service Applicant subject to conditions including the condition that EnergyAustralia must not disclose the Commercial Information to any other person unless the Service Applicant consents in writing to the disclosure. The Service Applicant may require EnergyAustralia to enter into a confidentiality agreement, on terms reasonably acceptable to both parties, with the Service Applicant in respect of any Commercial Information provided to EnergyAustralia.

4.6 A consent provided by the Service Applicant in accordance with clause 4.5 may be subject to the condition that the person to whom EnergyAustralia discloses the Commercial Information must enter into a separate confidentiality agreement with the Service Applicant.

5 Provision of Commercial Information by EnergyAustralia

5.1 EnergyAustralia must provide the following information to the Service Applicant in accordance with the negotiation programme prepared in accordance with clause 3.4:

(a) the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service to the Service Applicant;

(b) a demonstration to the Service Applicant that the proposed charges for providing the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service reflect those costs and/or the cost increment or decrement (as appropriate); and

(c) EnergyAustralia's arrangements for the assessment and review of the charges and the basis upon which they are made.

5.2 The Service Applicant may give a notice to EnergyAustralia requesting that EnergyAustralia provide it with all Commercial Information held by EnergyAustralia that is reasonably required by the Service Applicant to enable it to engage in effective negotiations with EnergyAustralia for the provision of a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service, including the following:

(a) a description of the nature of the Negotiated Distribution Service or a Negotiable Component of a Direct Control Service including what EnergyAustralia would provide to the Service Applicant as part of that service;

(b) the terms and conditions on which EnergyAustralia would provide the Negotiated Distribution Service or the Negotiable Component of a Direct Control

Service to the Service Applicant if not previously provided in accordance with subclause 5.1(a);

(c) the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service to the Service Applicant if not previously provided in accordance with subclause 5.1(b);

(d) a demonstration to the Service Applicant that the proposed charges for providing the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service reflect those costs and/or the cost increment or decrement (as appropriate); and

(e) EnergyAustralia's proposed arrangements for the assessment and review of the proposed charges for the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service and the basis upon which those charges are made if not previously provided in accordance with subclause 5.1(c).

Confidentiality Requirements

5.3 For the purposes of clause 5.1, Commercial Information does not include:

(a) confidential information provided to EnergyAustralia by another person; or

(b) information that EnergyAustralia is prohibited, by law, from disclosing to the Service Applicant.

5.4 EnergyAustralia may provide the Commercial Information in accordance with clause 5.2 subject to relevant conditions including the condition that the Service Applicant must not disclose the Commercial Information to any other person unless EnergyAustralia consents in writing to the disclosure. EnergyAustralia may require the Service Applicant to enter into a confidentiality agreement with EnergyAustralia, on terms reasonably acceptable to both parties, in respect of Commercial Information provided to the Service Applicant.

5.5 A consent provided to a Service Applicant in accordance with clause 5.4 may be subject to the condition that the person to whom the Service Applicant discloses the Commercial Information must enter into a separate confidentiality agreement with EnergyAustralia.

6 Assessment and Review of Charges and Basis of Charges

6.1 EnergyAustralia's must have arrangements for the assessment and review of the proposed charges for the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service and the basis upon which those charges are made.

6.2 EnergyAustralia must provide these arrangements to the Service Applicant in accordance with clause 5.1 or 5.2 as applicable.

7 Determination of impact on other Distribution Network Users and consultation with affected Distribution Network Users

7.1 EnergyAustralia must determine the potential impact on Distribution Network Users, other than the Service Applicant, of the provision of the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service.

7.2 EnergyAustralia must notify and consult with any affected Distribution Network Users and ensure that the provision of the Negotiated Distribution Service or the Negotiable Component of a Direct Control Service does not result in non-compliance with obligations to other Distribution Network Users under the NER.

8 Suspension of Timeframe for Provision of a Negotiated Distribution Service or a Negotiable Component of a D irect Control Service

8.1 The timeframes for negotiation of provision of a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service in Table 1, or as otherwise agreed between the parties, are suspended if:

(a) a dispute in relation to the Negotiated Distribution Service or a Negotiable Component of a Direct Control Service has been notified to the AER under Part 10 of the NEL, from the date of notification of that dispute to the AER until

(i) the withdrawal of the dispute under section 126 of the NEL;

(i) the termination of the dispute by the AER under section 131 or 132 of the NEL; or

(i) determination of the dispute by the AER under section 128 of the NEL;

(b) within 15 Business Days of EnergyAustralia requesting additional Commercial Information from the Service Applicant pursuant to clause 4, the Service Applicant has not supplied that Commercial Information;

(c) without limiting clauses 8.1(a) and (b), either of the parties does not promptly conform with any of its obligations as required b y this negotiating framework or as otherwise agreed by the parties;

(d) EnergyAustralia has been required to notify and consult with any affected Distribution Network Users under clause 6, from the date of notification to the affected Distribution Network Users until the end of the time limit specified by EnergyAustralia for any affected Distribution Network Users, or the receipt of such information from the affected Distribution Network Users whichever is the later regarding the provision of the Negotiated Distribution Service or Negotiable Component of a Direct Control Service.

(e) Each party will notify the other party if it considers that the timeframe has been suspended, within 5 business days of that suspension.

9 Dispute Resolution

9.1 All disputes between the parties as to the terms and conditions of access for the provision of a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service are to be dealt with by the AER in accordance with Part 10 of the NEL and Part L of the Transitional Rules

10 Payment of EnergyAustralia's Reasonable Costs

10.1 EnergyAustralia may give the Service Applicant a notice setting out EnergyAustralia's reasonable direct expenses incurred in the processing of the service applicants application.

10.2 The service applicant must, within 20 days of a notice being given i n accordance with this clause 9 pay to EnergyAustralia the amount set out in the Notice.

11 Termination of Negotiations

11.1 The Service Applicant may elect not to continue with its application for a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service and may terminate the negotiations by giving EnergyAustralia written notice of its decision to do so.

11.2 EnergyAustralia may terminate a negotiation under this framework by giving the Service Applicant written notice of its decision to do so where:

(a) EnergyAustralia believes on reasonable grounds that the Service Applicant is not conducting the negotiation under this negotiating framework in good faith;

(b) the Service Applicant consistently fails to comply with the requirements of the negotiating framework;

(c) the Service Applicant fails to comply with an obligation in this negotiating framework to undertake or complete an action within a specified or agreed timeframe, and does not complete the relevant action within 20 Business Days of a written request from EnergyAustralia;

(d) An act of Solvency Default occurs in relation to the Service Applicant.

12 Publication of Results of Negotiations on Website

12.1 EnergyAustralia will publish the outcomes of negotiations for Negotiated Distribution Services and Negotiable Components of Direct Control Services on its website .

13 Giving notices

13.1 A notice, consent, information, application or request that must or may be given or made to a party under this document is only given or made if it is in writing and delivered or posted to that party at its address set out below.

13.2 If a party gives the other party 3 Business Days' notice of a change of its address, a notice, consent, information, application or request is only given or made by that other party if it is delivered or posted to the latest address.

EnergyAustralia	
Name:	EnergyAustralia
Address:	GPO Box 4009, Sydney, NSW 2001 Attention: Network Connections
Service Applicant Name	
Name:	Service Applicant
Address:	The nominated address of the Service Applicant provided in writing to EnergyAustralia as part of the application

Time notice is given

13.3 A notice, consent, information, application or request is to be treated as giv en or made at the following time:

(a) if it is delivered, when it is left at the relevant address; or

(b) if it is sent by post, 2 Business Days after it is posted.

(c) If sent by facsimile transmission, on the day the transmission is sent (but only if the sender has a confirmation report specifying a facsimile number of the recipient, the number of pages sent and the date of transmission) .

13.4 If a notice, consent, information, application or request is delivered after the normal business hours of the party to whom it is sent, it is to be treated as having been given or made at the beginning of the next Business Day.

14 Miscellaneous

Governing law and jurisdiction

14.1 This document is governed by the law of the State of New South Wales.

14.2 The parties submit to the non-exclusive jurisdiction of the courts of the state of New South Wales.

14.3 The parties will not object to the exercise of judgment by the courts of the State of New South Wales on any basis.

Severability

14.4 If a clause or part of a clause of this negotiating framework can be read in a way that makes it illegal, unenforceable or invalid, but can also be read in a way that makes is legal, enforceable and valid, it must be read in the latter way.

14.5 If any clause or part of a clause is illegal, unenforceable or inv alid, that clause or part is to be treated as removed from this negotiating framework, but the rest of this negotiating framework is not affected.

Time for Action

14.6 If the day on or by which something is required to be done or may be done is not a Business Day, that thing must be done on or by the next Business Day.

15 Definitions and interpretation

15.1 Definitions

In this document the following definitions apply:

Business Day means a day on which all banks are open for business generally in Sydney, NSW.

Commercial Information shall include at a minimum, the following classes of information:

In relation to a Service Applicant, details of corporate structure, financial details relevant to creditworthiness and commercial risk and ownership of assets;

technical information relevant to the application for a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service;

financial information relevant to the application for a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service;

details of an application's compliance with any law, standard, NER or guideline.

Costs means any costs or expenses incurred by EnergyAustralia in complying with this negotiating framework or otherwise advancing the Servic e Applicant's request for the provision of a Negotiated Distribution Service or a Negotiable Component of a Direct Control Service or such other costs or expenses consistent with the NER, EnergyAustralia's Cost Allocation Methodology or any relevant part o f a distribution determination applying to EnergyAustralia.

EnergyAustralia means EnergyAustralia ABN 67505337385

Solvency Default means the occurrence of any of the following events in relation to the Service Applicant:

(a) An originating process or application for the winding up of the Service

Applicant (other than a frivolous or vexatious application) is filed in a court or a special resolution is passed to wind up the Service Applicant, and is not dismissed before the expiration of 60 days from s ervice on the Service Applicant;

(b) A receiver, receiver and manager or administrator is appointed in

respect of all or any part of the assets of the Service Applicant, or a provisional liquidator is appointed to the Service Applicant;

(c) A mortgagee, chargee or other holder of security, by itself or by or

through an agent, enters into possession of all or any part of the assets of the Service Applicant;

(d) A mortgage, charge or other security is enforced by its holder or becomes enforceable or can become enforceable with the giving of notice, lapse of time or fulfilment of a condition;

(e) The Service Applicant stops payment of, or admits in writing its inability to pay, its debts as they fall due;

(f) The Service Applicant applies for, consents to, or acquiesces in the appointment of a trustee or receiver of the Service Applicant or any of its property;

(g) A court appoints a liquidator, provisional liquidator, receiver or trustee, whether permanent or temporary, of all or any part of the Service Applicant's property;

(h) The Service Applicant takes any step to obtain protection or is granted protection from its creditors under any applicable legislation or a meeting is convened or a resolution is passed to appoint an administrator or controller (as defined in the Corporations Act 2001), in respect of the Service Applicant;

(i) A controller (as defined in the Corporations Act 2001) is appointed in respect of any part of the property of the Service Applicant;

j) Except to reconstruct or amalgamate while solvent, the Service Applicant enters into or resolves to enter into a scheme of arrangement, compromise or reconstruction proposed with its creditors (or any class of them) or with its members (or any class of them) or proposes re-organisation, re-arrangement moratorium or other administration of the Service Applicant's affairs;

(k) The Service Applicant is the subject of an event described in section 459C(2)(b) of the Corporations Act 2001; or

(l) Anything analogous or having a substantially similar effect to any of the events specified above happens in relation to the Service Applicant.

15.2 Interpretation

In this document, unless the context otherwise requires:

(a) terms defined in the NEL and the NER have the same meaning in this negotiating framework;

(b) a reference to any law or legislation or legislative provision includes any statutory modification, amendment or re-enactment, and any subordinate legislation or regulations issued under that legislation or legislative provision;

(c) a reference to any agreement or document is to that agreement or document as amended, novated, supplemented or replaced from time to time;

(d) a reference to a clause, part, schedule or attachment is a reference to a clause, part, schedule or attachment of or to this document unless otherwise stated;

(e) an expression importing a natural person includes any company, trust, partnership, joint venture, association, corporation, body corporate or governmental agency; and

(f) a covenant or agreement on the part of two or more persons binds them jointly and severally.

Appendix F: Integral Energy negotiating framework

Integral Energy's proposed negotiating framework

The Transitional Rules recognise that customers may require a service that is a *direct control service* but which has components that are more appropriately negotiated. To facilitate fair negotiation between the DNSP and customers for those components, the Transitional Rules require a DNSP to provide a basis for negotiating in the *negotiating framework*.

This Appendix summarises the key requirements of the Transitional Rules that relate to the *negotiating framework*. It indicates which components of Integral Energy's *direct control services* Integral Energy proposes to be Negotiable Components for the *2009 regulatory control period* and sets out Integral Energy's proposed *negotiating framework*.

1.1 Summary

Integral Energy offers *direct control services* to its customers. The Transitional Rules provide the option to provide customers with tailored *direct control services* to take account of their specific needs during the *2009 regulatory control period*. Integral Energy believes that customers may wish to take advantage of the opportunity during that period. Therefore, in accordance with the Transitional Rules, Integral Energy has set out the proposed Negotiable Components and a *negotiating framework* for those services.

1.2 Regulatory information requirements

The Transitional Rules requirements are summarised in Box 19.1.

Box 19.1: Negotiating framework regulatory information requirements
Part DA of the Transitional Rules deals with Negotiable Components for *direct control services*.
Clause 6.7A of the Transitional Rules allows the AER to determine that some components of *direct control services* are Negotiable Components.
Clause 6.7A.1 of the Transitional Rules sets out the principles relating to access to negotiable components.
Clause 6.7A.5 of the Transitional Rules requires the preparation of the *negotiating framework* that the DNSPs must comply with (clause 6.7A.2). It also stipulates the requirements of the *negotiating framework*.

This Appendix is intended to provide the information to address the Transitional Rules requirements.

1.3 Negotiable Components

For the purposes of the *2009 regulatory control period*, a Negotiable Component is a particular component :

(a) of a *direct control service* provided by Integral Energy; or

(b) which relates to the terms or conditions on which a *direct control service* or a component of the *direct control service* is provided by Integral,

which the AER has determined to be a negotiable component in a distribution determination pursuant to 6.7A(a) of the Rules but does not include *negotiated distribution services* or unregulated *distribution services*.

Integral Energy proposes that the following components of *direct control services* be classified as the Negotiable Components of *direct control services* with respect to the 2009 regulatory control period pursuant to clause 6.8.2(7) of the Transitional Rules:

(a) a *direct control service* that exceeds the network performance requirements which that *direct control service* is required to meet under any jurisdictional electricity legislation;

(b) a *direct control service* that, except to the extent that the network performance requirements which that *direct control service* is required to meet are prescribed under any jurisdictional electricity legislation, exceeds or does not meet the network performance requirements (whether as to quality or quantity) as are set out in schedule 5.1a or 5.1;

(c) a *direct control service* that is a *connection service* provided to serve a Distribution Network User or group of Distribution Network Users, at a single distribution network connection point, other than connection services that are provided by one Network Service Provider to another Network Service Provider to connect their networks where neither of the Network Service Providers is a Market Network Service Provider; or

(d) the terms and conditions in respect of which any of the above are provided.

1.4 Proposed negotiating framework

Integral Energy proposes the following negotiating framework:

1. Application of negotiating framework

1.1 This negotiating framework applies to Integral Energy and each Service Applicant who has made an application in writing to Integral Energy for the provision of a Negotiable Component

1.2 Integral Energy and any Service Applicant who wishes to receive a Negotiable Component from Integral Energy must comply with the requirements of this negotiating framework.

1.3 The requirements set out in this negotiating framework are additional to any requirements or obligations contained in the Transitional Rules. In the event of any inconsistency between this negotiating framework and any requirements in the Transitional Rules, the requirements of the Transitional Rules will prevail.

1.4 Nothing in this negotiating framework or in the Transitional Rules will be taken as imposing an obligation on Integral Energy to provide any service to the Service Applicant.

2. Obligation to negotiate in good faith

2.1 Integral Energy and the Service Applicant must negotiate in good faith the terms and conditions of access for the provision by Integral Energy of the Negotiable Component sought by the Service Applicant.

3. Timeframe for commencing, progressing and finalising negotiations

3.1 Paragraph 3.4 sets out the timeframe for commencing, progressing and finalising negotiations in relation to applications for Negotiable Components under the Transitional Rules.

3.2 The timeframes set out in paragraph 3.4 may be suspended in accordance with paragraph 8.

3.3 Integral Energy and the Service Applicant must use reasonable endeavours to adhere to the time periods specified in paragraph 3.4 during the negotiation for the supply of the Negotiable Component.

3.4 The preliminary program finalised under C in Table 1 may be modified from time to time by agreement of the parties, where such agreement must not be unreasonably withheld. Any such amendment to the preliminary program will be taken to be a reasonable period of time for commencing, progressing and finalising negotiations with a Service Applicant for the provision of the Negotiable Component for the purposes of 6.7A.5(c)(5) of the Transitional Rules. The requirement in paragraph 3.3 applies to the last amended preliminary program.

Table 1

	Event	**Indicative timeframe**
A	Receipt of written application for a Negotiable Component	X
B	Parties meet to discuss a preliminary program with milestones for supply of the Negotiable Component that represent a reasonable period of time for commencing, progressing and finalising negotiations for the provision of the Negotiable Component	X + 20 business days
C	Parties finalise preliminary program, which may include, without limitation, milestones relating to: • the request and provision of commercial information; and • notification and consultation with NEMMCO	X + 30 business days

	Event	Indicative timeframe
	and / or any affected Distribution Network Users.	
D	Integral Energy provides Service Applicant with an offer for the Negotiable Component	X + 120 business days
E	Parties finalise negotiations	X + 160 business days

3.5 Subject to paragraphs 3.2 to 3.4, Integral Energy and the Service Applicant must, following a request for a Negotiable Component, use their reasonable endeavours to:

3.5.1 hold a meeting within 20 Business Days of receipt of the application, or such other period as agreed by the parties, in order to agree a timetable for the conduct of negotiations and to commence discussion regarding other relevant issues;

3.5.2 progress the negotiations for the provision of a Negotiable Component by Integral Energy such that the negotiations may be finalised in accordance with the timetable referred to in paragraph 3.5.1;

3.5.3 adhere to any timetable established for the negotiation and to progress the negotiation in an expeditious manner; and

3.5.4 finalise the negotiations for the provision of a Negotiable Component by Integral Energy within a time period agreed by the parties.

3.6 Notwithstanding paragraph 3.1, or any other provision of this negotiating framework, the timeframes set out in paragraphs 3.2 to 3.4:

3.6.1 do not commence until payment of the amount to Integral Energy pursuant to paragraph 10;

3.6.2 recommence if there is a material change in the Negotiated Distribution Service sought by the Service Applicant, unless Integral Energy agrees otherwise.

3.7 At the conclusion of the negotiations between Integral Energy and the Service Applicant, whether by way of agreed outcome or termination pursuant to clause 11 of this Negotiating Framework, Integral Energy must publish the results of the negotiations on its website.

4. Provision of initial commercial information by Service Applicant

4.1 Integral Energy must request the Service Applicant to provide it with the Commercial Information held by the Service Applicant that Integral reasonably requires to enable it to engage in effective negotiations with the Service Applicant in relation to the application and to enable Integral Energy to submit Commercial Information to the Service Applicant. Integral Energy must use its reasonable endeavours to make the request within the period of time agreed by the parties pursuant to clause 3.

4.2 The Service Applicant must provide Integral Energy with the Commercial Information held by it which Integral Energy reasonably requires to engage in effective negotiations with the Service Applicant in relation to the application. Subject to paragraphs 4.3 and 4.4, the Service Applicant must use its reasonable endeavours to provide Integral Energy with the Commercial Information requested by Integral Energy in accordance with paragraph 4.1 within 10 Business Days of that request, or within a time period as agreed by the parties.

4.3 Notwithstanding paragraph 4.1, the obligation under paragraph 4.1 is suspended as at the date of notification of a dispute if a dispute under this negotiating framework arises until conclusion of the dispute in accordance with paragraph 9.

Confidentiality requirements – Commercial Information

4.4 Commercial Information may be provided by the Service Applicant subject to the condition that Integral Energy must not disclose the Commercial Information to any other person unless the Service Applicant consents in writing to the disclosure. The Service Applicant may require Integral Energy to enter into a confidentiality agreement, on terms reasonably acceptable to both parties, with the Service Applicant in respect of any Commercial Information provided to Integral Energy.

4.5 A consent provided by the Service Applicant in accordance with paragraph 4.4 may be subject to the condition that the person to whom Integral Energy discloses the Commercial Information must enter into a separate confidentiality agreement with the Service Applicant.

5. Provision of additional Commercial Information by the Service Applicant

Obligation to provide additional Commercial Information

5.1 Integral Energy may give a notice to the Service Applicant requesting the Service Applicant to provide Integral Energy with any additional Commercial Information that is reasonably required by Integral Energy to enable it to engage in effective negotiations with the Service Applicant in relation to the provision of a Negotiable Component or to clarify any Commercial Information provided pursuant to paragraph 4.

5.2 The Service Applicant must use its reasonable endeavours to provide Integral Energy with the Commercial Information requested by Integral Energy in accordance with paragraph 5.1 within 10 Business Days of the date of the request under paragraph 5.1, or such other period as agreed by the parties.

5.3 The provision of additional Commercial Information by the Service Applicant pursuant to clause 5.2 is subject to the provisions in clauses 4.4 and 4.5 above.

6. Provision of Commercial Information by Integral Energy

Obligation to provide commercial information

6.1 Integral Energy must provide the Service Applicant with all Commercial Information held by Integral Energy that is reasonably required by a Service Applicant to enable it to engage in effective negotiations with Integral Energy for the provision of a Negotiable Component within a timeframe agreed by the parties, including the following information:

6.1.1 a description of the nature of the Negotiable Component including what Integral Energy would provide to the Service Applicant as part of that service;

6.1.2 the terms and conditions on which Integral Energy would provide the Negotiable Component to the Service Applicant;

6.1.3 the reasonable costs and/or the increase or decrease in costs (as appropriate) of providing the Negotiable Component to the Service Applicant which demonstrate to the Service Applicant that the charges for providing the Negotiable Component reflect those costs and/or the cost increment or decrement (as appropriate).

6.2 For the purpose of paragraph 6.1.3, Integral Energy must have appropriate arrangements for the assessment and review of the charges and the basis on which they are made.

Confidentiality requirements

6.3 Integral Energy may provide the Commercial Information in accordance with paragraph 6.1 subject to the condition that the Service Applicant must not disclose the Commercial Information to any other person unless Integral Energy consents in writing to the disclosure. Integral Energy may require the Service Applicant to enter into a confidentiality agreement with Integral Energy, on terms reasonably acceptable to both parties, in respect of Commercial Information provided to the Service Applicant.

6.4 A consent provided by a Service Applicant in accordance with paragraph 6.3 may be subject to the condition that the person to whom the Service Applicant discloses the Commercial Information must enter into a separate confidentiality agreement with Integral Energy.

7. Determination of impact on other Distribution Network Users and consultation with affected parties

7.1 Integral Energy must determine the potential impact on Distribution Network Users, other than the Service Applicant, of the provision of the Negotiable Component.

7.2 Integral Energy must notify and consult with any affected Distribution Network Users and ensure that the provision of the Negotiable Component does not result in non-compliance with obligations in relation to other Distribution Network Users under the Rules.

8. Suspension of timeframe for provision of Negotiable Component

8.1 The timeframes for negotiation of provision of a Negotiable Component as contained within this negotiating framework, or as otherwise agreed between the parties, are suspended if:

8.1.1 within 15 Business Days of Integral Energy providing the Commercial Information to the Service Applicant pursuant to paragraph 6.1, the Service Applicant does not formally accept that Commercial Information and the parties have agreed a date for the undertaking and conclusion of commercial negotiations;

8.1.2 a dispute in relation to the Negotiable Component has been notified to Integral Energy or the Service Applicant (as applicable) in accordance with Chapter 8 of the Rules, from the date of that notification until the date of withdrawal of the dispute or resolution of the dispute under Chapter 8 of the Rules (as applicable);

8.1.3 within 10 Business Days of Integral Energy requesting additional Commercial Information from the Service Applicant pursuant to paragraph 5, the Service Applicant has not supplied that Commercial Information;

8.1.4 without limiting paragraphs 8.1.1 to 8.1.3, if either of the parties does not promptly meet any of its obligations as required by this negotiating framework or as otherwise agreed by the parties;

8.1.5 Integral Energy has been required to notify and consult with any affected Distribution Network Users under paragraph 7.2, or NEMMCO at any time regarding the provision of the Negotiable Component. In those circumstances, the time frame for the negotiations will be suspended from the date of notification to the affected Distribution Network Users or NEMMCO until:

(a) the end of the time limit specified by Integral Energy for any affected Distribution Network Users or NEMMCO; or

(b) the receipt of information from the affected Distribution Network Users or NEMMCO regarding the provision of the Negotiable Component,

whichever is the later.

9. Dispute resolution

9.1 All disputes between the parties as to the terms and conditions of access for the provision of a Negotiable Component are to be dealt with in accordance with the NEL and Chapter 8 of the Rules.

10. Payment of Integral Energy's Costs

10.1 Prior to commencing negotiations, the Service Applicant must pay an application fee to Integral Energy. The fee must be no more than Integral Energy's reasonable estimate of its costs in dealing with the application. The payment is to be made in accordance with clause 6.7A.5(c)(5) of the Rules.

10.2 The application fee lodged pursuant to paragraph 10.1 will be deducted from the reasonable direct Costs incurred in processing the Service Applicant's application to Integral Energy for the provision of a Negotiable Component.

10.3 From time to time, Integral Energy may give the Relevant Service Applicant a notice setting out the reasonable direct Costs incurred by Integral Energy and the off-set of any amount applicable under paragraph 10.1.

10.4 If the aggregate of the reasonable direct Costs exceed the amount paid by the Service Applicant pursuant to paragraph 10.1, the Service Applicant must, within 20 Business Days of the receipt of a notice in accordance with paragraph 10.3, pay Integral Energy the amount stated in the notice. If the aggregate of its actual reasonable direct Costs is less than the amount paid by the Service Applicant pursuant to paragraph 10.1, Integral Energy must promptly notify the Service Applicant and must within 20 Business Days of the date of that notice refund to the Service Applicant the amount by which the application fee paid by the Service Applicant under paragraph 10.1 exceeds Integral's actual aggregate reasonable direct Costs.

10.5 Integral Energy may require the Service Applicant to enter into a binding agreement addressing conditions, guarantees and other matters in relation to the payment of on-going Costs.

11. Termination of negotiations

11.1 The Service Applicant may elect not to continue with its application for a Negotiable Component and may terminate the negotiations by giving Integral Energy written notice of its decision to do so.

11.2 Integral Energy may terminate a negotiation under this framework by giving the Service Applicant written notice of its decision to do so where:

11.2.1 Integral Energy believes on reasonable grounds that the Service Applicant is not conducting the negotiation under this negotiating framework in good faith;

11.2.2 Integral Energy reasonably believes that the Service Applicant will not acquire any Negotiable Component;

11.2.3 An act of Solvency Default occurs in relation to the Service Applicant.

12. Giving notices

12.1 A notice, consent, information, application or request that must or may be given or made to a party under this document is only given or made if it is in writing and delivered or posted to that party at its address set out below.

If a party gives the other party 5 Business Days' notice of a change of its address, a notice, consent, information, application or request is only given or made by that other party if it is delivered or posted to the latest address.

<u>Integral Energy</u>

Name: Integral Energy Australia

Address: 51 Huntingwood Drive, Huntingwood NSW 2148 or

PO Box 6366, Blacktown NSW 2148

Service Applicant

Name: Service Applicant

Address: The nominated address of the Service Applicant provided in writing to Integral Energy as part of the application

Time notice is given

12.2 A notice, consent, information, application or request is to be treated as given or made at the following time:

12.2.1 if it is delivered, when it is left at the relevant address;

12.2.2 if it is sent by post, 2 Business Days after it is posted;

12.2.3 if sent by facsimile transmission, on the day the transmission is sent (but only if the sender has a confirmation report specifying a facsimile number of the recipient, the number of pages sent and the date of transmission); or

12.2.4 if sent by email once acknowledged as received by the addressee.

12.3 If a notice, consent, information, application or request is delivered after the normal business hours of the party to whom it is sent, it is to be treated as having been given or made at the beginning of the next Business Day.

13. Definitions and interpretation

Definitions

13.1 In this document the following definitions apply:

Business Day means a day on which all banks are open for business generally in Sydney, New South Wales.

Commercial Information includes, but is not limited to, the following classes of information:

- details of corporate structure;
- financial details relevant to creditworthiness and commercial risk;
- ownership of assets;
- technical information relevant to the application for a Negotiable Component;

- financial information relevant to the application for a Negotiable Component;
- details of an application's compliance with any law, standard, NER or guideline,

but does not include:

- confidential information provided by another person to either:
  - the Service Applicant; or
  - Integral Energy;
- information that the Service Applicant is prohibited, by law, from disclosing to Integral Energy; or
- information that Integral Energy is prohibited, by law, from disclosing to the Service Applicant.

Costs means any costs or expenses incurred by Integral Energy in complying with this negotiating framework or otherwise advancing the Service Applicant's request for the provision of a Negotiable Component.

Integral Energy means Integral Energy Australia, ABN 59 253 130 878.

Negotiable Component has the meaning given in clause 1.3.

Solvency Default means the occurrence of any of the following events in relation to the Service Applicant:

(a) An originating process or application for the winding up of the Service Applicant (other than a frivolous or vexatious application) is filed in a court or a special resolution is passed to wind up the Service Applicant, and is not dismissed before the expiration of 60 days from service on the Service Applicant;

(b) A receiver, receiver and manager or administrator is appointed in respect of all or any part of the assets of the Service Applicant, or a provisional liquidator is appointed to the Service Applicant;

(c) A mortgagee, chargee or other holder of security, by itself or by or through an agent, enters into possession of all or any part of the assets of the Service Applicant;

(d) A mortgage, charge or other security is enforced by its holder or becomes enforceable or can become enforceable with the giving of notice, lapse of time or fulfilment of a condition;

(e) The Service Applicant stops payment of, or admits in writing its inability to pay, its debts as they fall due;

(f) The Service Applicant applies for, consents to, or acquiesces in the appointment of a trustee or receiver of the Service Applicant or any of its property;

(g) A court appoints a liquidator, provisional liquidator, receiver or trustee, whether permanent or temporary, of all or any part of the Service Applicant's property;

(h) The Service Applicant takes any step to obtain protection or is granted protection from its creditors under any applicable legislation or a meeting is convened or a resolution is passed to appoint an administrator or controller (as defined in the Corporations Act 2001), in respect of the Service Applicant;

(i) A controller (as defined in the Corporations Act 2001) is appointed in respect of any part of the property of the Service Applicant;

(j) Except to reconstruct or amalgamate while solvent, the Service Applicant enters into or resolves to enter into a scheme of arrangement, compromise or reconstruction proposed with its creditors (or any class of them) or with its members (or any class of them) or proposes re-organisation, re-arrangement moratorium or other administration of the Service Applicant's affairs;

(k) The Service Applicant is the subject of an event described in section 459C(2)(b) of the Corporations Act 2001; or

(l) Anything analogous or having a substantially similar effect to any of the events specified above happens in relation to the Service Applicant.

Interpretation

13.2 In this document, unless the context otherwise requires:

13.2.1 terms defined in the Transitional Rules have the same meaning in this negotiating framework;

13.2.2 a reference to any law or legislation or legislative provision includes any statutory modification, amendment or re-enactment, and any subordinate legislation or regulations issued under that legislation or legislative provision;

13.2.3 a reference to any agreement or document is to that agreement or document as amended, novated, supplemented or replaced from time to time;

13.2.4 a reference to a paragraph, part, schedule or attachment is a reference to a paragraph, part, schedule or attachment of or to this document unless otherwise stated;

13.2.5 an expression importing a natural person includes any company, trust, partnership, joint venture, association, corporation, body corporate or governmental agency; and

13.2.6 a covenant or agreement on the part of two or more persons binds them jointly and severally.

Appendix G: Miscellaneous services, monopoly services and emergency recoverable works

G.1 Miscellaneous services

G.1.1 Supply of Conveyancing Information desk inquiry

The provision of information regarding the availability of supply, presence of the DNSP's equipment, power lines and like information for property conveyancing purposes undertaken without any physical inspection of a site, other than the provision of information or the answering of inquiries relating to any matter under freedom of information legislation.

G.1.2 Supply of conveyancing information field visit

The provision of information regarding the availability of supply, presence of the DNSP's equipment, power lines and like information for property conveyancing purposes undertaken by a physical inspection of a site, other than the provision of information or the answering of inquiries relating to any matter under freedom of information legislation.

G.1.3 Meter test

The testing of a meter in accordance with clause 6.4 of the Market Operations Rule (NSW Rules for Electricity Metering) No. 3 of 2001 (except for metering installation types 1 to 4, the testing of which is an unregulated distribution service).

G.1.4 Special meter reading

This service:

1. has the same meaning as the meaning given to the expression 'special meter read' in the Market Operations Rule (NSW Rules for Electricity Metering) No. 3 of 2001 (but excludes any special meter reading of metering installation types 1 to 4, which is an unregulated distribution service);

and applies in each of the following circumstances:

2. where a customer or a retail supplier requests that the DNSP undertake a special meter read, (but does not apply where the special meter read was requested solely to verify the accuracy of a scheduled meter read and the special meter read reveals that the scheduled meter read was inaccurate or in error) or
3. where the DNSP attends at a customer's premises for the sole purpose of discharging the DNSP's obligation to read the customer's meter within the period specified by law (but not where the DNSP merely chooses to read the customer's meter without being under a legal obligation to do so) and on attending the customer's premises the DNSP is unable (through no act or omission of the DNSP), to gain access to the meter or
4. where the DNSP and the customer agree on an appointed time at which the DNSP may attend the customer's premises to enable the DNSP to discharge the DNSP's legal obligation referred to in section G.1.4(3) and when the DNSP attended at the

customer's premises at the appointed time the DNSP (through no act or omission of the DNSP), was unable to gain access to the customer's meter.

G.1.5 Disconnection visit (acceptable payment received)

A site visit to a customer's premises on an occasion for the purpose of disconnecting the customer's supply for breach by the customer of a customer supply contract or a customer connection contract, where the disconnection does not occur on that occasion.

G.1.6 Disconnection at meter box

A site visit to a customer's premises to:

1. disconnect the supply of electricity to a customer via either the main switch or service fuse removal for breach by the customer of a customer supply contract or a customer connection contract, or where a retail supplier has requested that the supply to the customer be disconnected and
2. reconnect the supply following the disconnection in section G.1.6(1).

G.1.7 Disconnection at pole top/pillar box

A site visit to a customer's premises:

1. to disconnect the supply of electricity to a customer at the pole top or pillar box for breach by the customer of a customer supply contract or a customer connection contract, or where a retailer supplier has requested that the supply to a customer be disconnected, where the customer has denied access to the meter or had prior to the visit, reconnected supply without authorisation by the DNSP following a previous disconnection and
2. to reconnect the supply, following the disconnection in section G.1.7(1).

G.1.8 Rectification of illegal connection

Work undertaken by a DNSP to the property of the DNSP or to the property of another person in order to:

1. rectify damage or
2. prevent injury to persons or property,

resulting from conduct that constitutes an offence under part 6, division 1 of the *Electricity Supply Act 1995* (NSW).

G.1.9 Off–peak conversion

The alteration of the off–peak meter at a customer's premises for the purpose of changing the hours of the meter's operation.

G.1.10 Reconnection outside normal business hours

1. The provision of the reconnection component of the service described in sections G.1.6(2) and G.1.7(2) outside the hours of 7.30 am and 4.00 pm on a working day, at the request of a customer or

2. The connection of electricity to a new customer outside the hours of 7.30 am and 4.00 pm on a working day at the request of the customer.

G.2 Monopoly services

G.2.1 Design information

The provision of information by a DNSP to enable an ASP accredited for level 3 work to prepare a design drawing and to submit it for certification.

This may include without limitation:

1. deriving the estimated loading on the system, technically known as the ADMD (after diversity maximum demand). This estimate depends on such factors as the number of customers served and specific features of the customer's demand
2. copying drawings that show existing low and high voltage circuitry (geographically and schematically) and adjacent project drawings
3. specifying the preferred sizes for overhead wires (conductors) or underground wires (cables)
4. specifying switchgear configuration type, number of pillars, lights etc
5. determining the special requirements of the DNSP's planning departments necessary to make electrical supply available to a development and cater for future projects
6. any necessary liaison with designers associated with assistance in sourcing design information and developing designs
7. nominating network connection points.

G.2.2 Design certification

A certification by a DNSP that a design (if implemented) will not compromise the safety or operation of the DNSP's distribution system.

This may include, without limitation:

1. certifying that the design information/project definition have been incorporated in the design
2. certifying that easement requirements and earthing details are shown
3. considering design issues, including checking for over–design and mechanisms to permit work on high voltage systems without disruption to customers' supply (adequate low voltage parallels)
4. certifying that funding details for components in the scope of works are correct
5. certifying that there are no obvious errors that depart from the DNSP's design standards and specifications
6. certifying that shared assets are not over-utilised to minimise developer's connection costs and that all appropriate assets have been included in the design

7. auditing design calculations such as voltage drop calculations, conductor clearance (stringing) calculations etc
8. certifying that a bill of materials has been submitted
9. certifying that an environmental assessment has been submitted by an accredited person and appropriately checked.

G.2.3 Design rechecking

The rechecking of a design submitted under section 1.2.2, except where the modifications to a design are of a trivial or minor nature.

G.2.4 Inspection of service work (level 1 work)

The inspection by a DNSP of work undertaken by an ASP accredited to perform level 1 work, for the purpose of ensuring the quality of assets to be handed over to the DNSP.

G.2.5 Inspection of service work (level 2 work)

The inspection by a DNSP of work performed by an ASP accredited to perform level 2 work, complying with the condition below.

Condition

The minimum number of inspections required must correspond to the grade of the DNSP in table G.1 below:

Table G.1: Inspection rate

Grade	Number of inspections
A	1 inspection per 25 jobs
B	1 inspection per 5 jobs
C	Each job to be inspected

G.2.6 Re–inspection of level 1 or level 2 work

The re–inspection by a DNSP of work (other than customer installation work) undertaken by an ASP accredited to perform level 1 or level 2 work, for the reason that on first inspection the work was found not to be satisfactory.

G.2.7 Re–inspection of work of a service provider

The re–inspection by a DNSP of customer installation work undertaken by a service provider for the reason that on first inspection the work was found not to be satisfactory.

G.2.8 Access permit

The provision of a permit by a DNSP to a person authorised by law to work on, or near, a distribution system.

This may include without limitation:

1. researching and documenting the request for access
2. documenting the actual switching process
3. programming the work
4. control room activities
5. fitting and removing of operational earths
6. the actual switching together with any operator's transport costs
7. identification of any customers who will be interrupted
8. low voltage switching and paralleling of substations that permits high voltage work without disrupting supply to other customers.

G.2.9 Substation commissioning

The commissioning by a DNSP of a new substation, (whether it is a single pole, padmount/kiosk or indoor/chamber) and includes:

1. all necessary pre–commissioning checks and tests prior to energising the substation via the high voltage switchgear and closing the low voltage circuit breaker, links or fuses and
2. the setting or resetting of protection equipment.

G.2.10 Administration

Work of an administrative nature (not including work of an administrative nature described in section G.2.11), involving the processing of level 1 and/or level 3 work where the customer is lawfully required to pay for the level 1 and /or level 3 work.

This may include without limitation:

1. checking supply availability
2. processing applications
3. correspondence from application to completion
4. record–keeping
5. requesting and receiving fees (initially, then prior to design and after certification)
6. receiving design drawings (registering and copying)
7. raising an order for high voltage work
8. calculating high voltage reimbursements
9. calculating the cost of a project and warranty/maintenance bond
10. organising refunds to developers for high voltage work
11. liaising with developers via phone and facsimile
12. updating geographic information systems (GIS) and mapping.

G.2.11 Notice of arrangement

Work of an administrative nature performed by a DNSP where a local council requires evidence in writing from the DNSP that all necessary arrangements have been made to supply electricity to a development.

This may include without limitation:

1. receiving and checking linen plans and 88B Instruments
2. copying linen plans
3. checking and recording easement details
4. preparing files for conveyancing officers
5. liaising with developers if errors or changes are required
6. checking and receiving duct declarations and any amended linen plans and 88B Instruments approved by a conveyancing officer
7. preparing notifications of arrangement.

G.2.12 Access

The provision of access to switchrooms, substations and the like to an ASP who is accompanied by a member of staff of a DNSP, but does not include the circumstance where an ASP is provided with keys for the purpose of securing access and is not accompanied by a member of staff of the DNSP.

G.2.13 Authorisation

The annual authorisation by a DNSP of individual employees or sub–contractors of an ASP to carry out work on or near the DNSP's distribution system.

This may include without limitation:

1. familiarisation and training in the DNSP's safety rules and access permit requirements
2. induction in the unique aspects of the network
3. verification that the applicant has undertaken the necessary safety training (resuscitation etc) within the last 12 months
4. conducting interviews/examinations for access permit recipients
5. issuing authorisation cards.

G.2.14 Site establishment

The issue of a meter by a DNSP and its co–ordination with NEMMCO for the purpose of establishing a NMI in MSATS for new premises or for any existing premises for which NEMMCO requires a new NMI and for checking and updating network load data.

G.3 Emergency recoverable works

Emergency work undertaken by a DNSP to repair damage to the distribution system of the DNSP, where the damage is the consequence of the act or omission of a person, for which that person is liable to another (which may include the DNSP) for that damage.

For example, emergency work undertaken by a DNSP to repair damage to the DNSP's distribution system resulting from a motor vehicle collision where the driver was negligent.

G.4 Definitions and interpretation

G.4.1 Definitions

(1) In this appendix:

ASP means an accredited service provider and is a person who has been accredited under Part 10 Electricity Supply (General) Regulation 2001 (NSW)

MSATS means the market settlement and transfer system operated by NEMMCO

NMI means a national metering identifier

service provider means a person who may lawfully undertake customer installation work

(2) In this appendix the following expressions have the meaning given to them in the *Electricity Supply Act 1995* (NSW):

electricity supply contract

electricity connection contract

retail supplier.

(3) References to sections are references to sections in this appendix.

G.4.2 Interpretation of grade or level of accreditation

1. In this appendix, the reference to a grade or level, means the grade or level for which an ASP is accredited, applying the classification system in table 2 below.
2. If the classification system in table G.2 is amended during the next regulatory control period, the reference in this appendix to a grade or level will be taken to be a reference to the grade or level in the amended classification system that most closely approximates the grade or level in table G.2.

Table G.2: Classification of accreditation

Accreditation	Type of work	Category
Level 1	Construction of transmission and distribution works, including high and low voltage, overhead and underground reticulation and substations.	Underground (UG) Overhead (OH)
Level 2	Service Work: Construction and/or installation of the service line interface between the distribution system and consumer terminals, including metering services	Disconnection and reconnection Underground (UG) service lines Overhead (OH) service lines Metering and energising new installations Installing contestable metering – under review
Level 3	Design of transmission and distribution works	Underground (UG) Overhead (OH)

Appendix H: Fees and charges - miscellaneous services, monopoly services and emergency recoverable works

H.1 Introduction

The miscellaneous services, monopoly services and emergency recoverable works in this appendix (having the abbreviated descriptions given to them in sections H.3, H.4 and H.5 respectively) have the full meaning given to them in appendix G of this final decision.

H.2 Levying charges for miscellaneous services, monopoly services and emergency recoverable works

a. The charge that may be levied by a DNSP for the provision of a miscellaneous service described in section H.3 or emergency recoverable works specified in section H.5, must not be more than (but may be less than) the charge specified or calculated for the miscellaneous service in section H.3 or the emergency recoverable work in section H.5 respectively.

b. Unless otherwise specified, the charge that is to be levied by a DNSP for the provision of a monopoly service described in section H.4, must not be more than or less than the charge specified or calculated for that monopoly service in that section.

c. The charges for miscellaneous services, monopoly services and emergency recoverable works in this appendix are to be levied in accordance with the conditions (if any) specified in appendix G of this final decision applying to each service and in accordance with the conditions accompanying the respective sections in this appendix.

H.3 Miscellaneous services

H.3.1 Charges for miscellaneous services

The charges in table H.1 below apply:

Table H.1: Charges for miscellaneous services

Miscellaneous service	$
Special meter reading	44
Meter test	73
Supply of conveyancing information – desk inquiry	37
Supply of conveyancing information – field visit	73
Off-peak conversion	59
Disconnection visit (acceptable payment received)	44
Disconnection at meter box	88
Disconnection at pole top/pillar box	148
Rectification of illegal connection	221
Reconnection outside business hours	95

H.3.2 Conditions relating to charges for miscellaneous services

a. Disconnection at meter box and pole/top pillar box.

   For the avoidance of doubt, if, following a request from a customer, the reconnection component of the services described in section H.3.1 as ‘disconnection at meter box’ and ‘disconnection at pole top/pillar box’ are provided outside the hours of 7.30 am and 4.00 pm on a working day, the charge that the DNSP may levy for the provision of each of those services will be the charge for each service in section H.3.1 plus the charge for the service described as ‘reconnection outside normal business hours’, if applicable.

b. Meter test.

   If the service described as ‘meter test’ is undertaken on premises serviced by more than one meter the following applies:

   i. if the meter test reveals that all of the meters are operating satisfactorily, a DNSP may only levy one charge for the provision of the service as if the meter test were undertaken on a single meter

   ii. if the meter test reveals that one or more of the meters are not operating satisfactorily, the DNSP may not levy any charge for the provision of the service.

c. Special meter reading.

   A charge may not be levied for the service described as ‘special meter reading’ in either of the following circumstances:

   i. where the customer is moving or is about to move premises or

   ii. where the service reveals that a scheduled meter reading was inaccurate.

d. Off–peak conversion

   A charge for the service described as ‘off–peak conversion’ may only be levied for each occasion that the service is provided in excess of once in any 12 month period.

H.4 Monopoly services

H.4.1 Charges for monopoly services

Table H.4 Charges for monopoly services

Monopoly service	Underground urban residential subdivision (vacant lots)	Rural overhead subdivisions and rural extensions	Underground commercial and industrial or rural subdivisions (vacant lots – no development)	Commercial and industrial developments	Asset relocation or street lighting
Design information	Up to 5 lots $159 6 to 10 lots $239 11 to 40 lots $398 Over 40 lots $478	R2 per hour	R2 per hour	R2 per hour	R2 or R3 per hour (see para 1.4.2)
Design certification	Up to 5 lots $80 6 to 10 lots $159 11 to 40 lots $239 Over 40 lots $318	1 to 5 poles $80 6 to 10 poles $159 11 or more poles $239	Up to 10 lots $159 11 to 40 lots $239 Over 40 lots $478	R3 per hour	R2 or R3 per hour (see para 1.4.2)
Design rechecking	R2 per hour	R2 per hour	R2 per hour	R3 per hour	R2 or R3 per hour (see para 1.4.2)
Inspection of service work (level 1 work)	Grade / A per lot / B per lot / C per lot First 10 lots $40 $96 $200 Next 40 lots $24 $56 $120 Remainder $8 $32 $56	Grade / A per pole / B per pole / C per pole 1 - 5 poles $48 $96 $176 6 - 10 poles $40 $80 $159 11+ poles $32 $56 $120 (see para 1.4.2)	Grade / A per lot / B per lot / C per lot First 10 lots $40 $96 $200 Next 40 lots $40 $96 $200 Remainder $40 $96 $200	R2 or R3 per hour	R2 or R3 per hour (see para 1.4.2)
Access permit	Residential subdivisions: $27 per lot combined fee	$1181 maximum per access permit	$1181 maximum per access permit	$1181 maximum per access permit	$1181 maximum per access permit
Substation commissioning		$886 per substation (see para 1.4.2)	$886 per substation (see para 1.4.2)	$886 per substation (see para 1.4.2)	$886 per substation (see para 1.4.2)
Administration	Up to 5 lots $193 6 to 10 lots $258 11 to 40 lots $322 Over 40 lots $387	Up to 5 poles $193 6 to 10 poles $258 11 or more poles $387	R1 per hour (max 6 hours)	R1 per hour (max 6 hours)	R1 per hour
Notice of arrangement	$193				
Re-inspection (level 1 and 2 work)	R2 per hour (maximum 1 hour per level 2 reinspection)				
Re-inspection (service provider)	$80 For the purpose of para 1.2(b), a DNSP may charge a fee that is less than this fee, but not a fee that is more than this fee.				
Access	R1 per hour				
Authorisation	$159				
Inspection of service work (level 2 work)	All service connections: A Grade: $20 per NOSW (NOSW = Notification of service work)	B Grade: $33 per NOSW	C Grade: $96 per NOSW		
Site establishment	$139				

H.4.2 Conditions relating to charges for monopoly services

a. Inspection

For the service described as 'inspection':

i. in the case of 'commercial and industrial developments' and 'asset relocation or street lighting', the level of inspection is to be determined by the DNSP prior to performing the service

ii. the grade specified is the grade of the ASP, accredited for that grade

iii. in the case of 'rural overhead subdivisions and rural extensions', the charge applies to inspections (other than substation poles) and represents the total charge for three separate visits. For substation poles the charge for ASP grade A is $279; for grade B is $557 and for grade C is $703.

b. Substation commissioning

For the service described as 'substation commissioning' (other than in the case of 'underground urban residential subdivision vacant lots') the charge specified is to be levied only where it is a single transformer/RMI unit. In all other cases the service is to be charged at the R3 labour rate.

c. Lots

In table H.4, where the monopoly service relates to a service connection required for multiple dwelling subdivisions, the per lot fee in that table should be applied per service connection.

d. Design information/design certification/ design rechecking

For the services described as 'design information', 'design certification' and 'design rechecking', the labour rate (R2 or R3) is to be applied based on the DNSP's assessment of the level of skill required to perform the service.

e. Travel time

In addition to the charge specified or calculated under section H.4.1, a DNSP must charge for that amount of travel time (permitted for that DNSP in table H.5 below) associated with the inspection of level 1 work at the R2 labour rate.

Table H.5: Travel time

DNSP	Amount of travel time permitted
EnergyAustralia	30 minutes
Integral Energy	30 minutes
Country Energy	60 minutes

f. Overtime

If a monopoly service is provided outside the hours of 7.30 am and 4.00 pm on a working day at the request of an ASP (other than where the DNSP requires that the work be performed outside those hours) the charge that the DNSP may impose for the provision of that service will be an amount up to 175 per cent of the charge for that service in section H.4.1.

g. Labour rates

    i. In section H.4.1 the references to R1, R2 and R3 denote the class of labour which performs the service at the hourly rate corresponding to the class in table 6 below.

    ii. For the purpose of the labour class R2 in the table, the DNSP will determine whether the service is to be provided by an inspector or an engineer at that class, depending on the nature and complexity of the service.

Table H.6: Labour rates

Labour class	Hourly rate
Admin R1	$64
Design R2a	$80
Inspector R2b	$80
Engineer R3	$96

H.5 Emergency recoverable works

H.5.1 Charges for emergency recoverable works

a. The charge that a DNSP may levy for emergency recoverable works must not exceed the sum of the following:

    i. 110 per cent of the costs (other than labour costs) actually incurred in providing the emergency recoverable works and

    ii. the cost of labour actually used to undertake the emergency recoverable works determined by applying 150 per cent of the R2 labour rate for that labour.

b. For the avoidance of doubt, in the application of section H.5.1(a)(2), where a DNSP retains labour for a specified period for the purpose of that labour undertaking emergency recoverable works, the DNSP may only charge for so much of that specified period during which the labour actually undertakes the emergency recoverable works. For example, if a DNSP retains labour for a minimum specified period of four hours and the time required to actually undertake the emergency recoverable works is only one hour, the DNSP may only charge for the one hour and not the four hours.

H.5.2 Conditions for emergency recoverable works

The charges for emergency recoverable works in section H.5.1 apply irrespective of whether the works are provided on a working day or the time of day at which they are provided.

H.6 Definitions and interpretation

In this appendix, unless the context requires otherwise:

a. expressions used in this appendix that are defined in appendix G of this final decision, have the meaning given to them in that appendix G

b. interpretation provisions in appendix G of this final decision apply to this appendix

c. references to sections are references to sections of this appendix.

Appendix I: Transmission use of system overs and unders account

To demonstrate compliance with clause 6.18.7 of the transitional chapter 6 rules and this final decision for the next regulatory control period, the AER requires the NSW DNSPs to maintain a transmission use of system (TUOS) overs and unders account. The NSW DNSPs must provide information on this account to the AER as part of their annual pricing proposals under clause 6.18.2(b)(7) of the transitional chapter 6 rules.

As part of their pricing proposals for each regulatory year of the next regulatory control period, the NSW DNSPs must provide the amounts for the following entries in their TUOS overs and unders account for the most recently completed regulatory year, the current regulatory year and the next regulatory year:

1. opening balance for each year
2. interest accrued on the opening balance for each year, calculated at the rate of the post–tax nominal rate of return as approved by the AER in its distribution determination, or the equivalent nominal rate of return approved by IPART for the 2004–09 regulatory control period
3. the amount representing the revenue recovered from TUOS charges applied in respect of that year, less the amounts of all transmission related payments made by the DNSP in respect of that year
4. an adjustment to the net amount in item 3 by six months of interest, accrued at the approved nominal rate of return
5. summation of the above amounts to derive the closing balance for each year.

The NSW DNSPs must provide details of calculations in the format set out in table I.1 of this final decision.

For the avoidance of doubt, amounts may be either positive or negative and when added to each other, subtracted from each other or multiplied by another number may also yield, as the case may be, positive or negative amounts.

Amounts provided for the most recently completed regulatory year must be audited. Amounts for the current and next regulatory year will be regarded as estimates and forecasts respectively.

For amounts and information relating to 2007–08 and 2008–09, the NSW DNSPs will calculate and present these to the AER in accordance with Annexure 7 of IPART's *NSW Electricity Distribution Pricing 2004/05 to 2008/09 Final Determination*.

In proposing variations to the amount and structure of TUOS charges, the NSW DNSPs are to achieve a zero expected balance on their TUOS overs and unders accounts at the end of each regulatory year in the next regulatory control period.

Table I.1 Example calculation of TUOS overs and unders account ($'000)

	year t–2 (actual)	year t–1 (estimate)	year t (forecast)
Revenue from TUOS charges	36 221	36 836	40 968
Transmission charges to be paid to TNSPs	25 214	27 602	35 791
Settlement residue payments			
Avoided TUOS payments	572	638	681
Inter-DNSP payments	8579	9575	10 221
Total transmission related payments (net of residue)	34 365	37 816	46 694
Over (under) recovery for financial year	1856	–980	–5726
Overs and unders Account			
Annual rate of interest applicable to balances	9.70%	9.70%	9.70%
Semi-annual rate of interest	4.74%	4.74%	4.74%
Opening balance	3624	5919	5467
Interest on opening balance	351	574	530
Over/ under recovery for financial year	1856	–980	–5726
Interest on over/ under recovery	88	–46	–271
Closing balance	5919	5467	0

Appendix J: Changes to tariff structures and the weighted average price cap and side constraint formulas

Changes to tariff structures can occur for customers in the following circumstances:

- the introduction of new tariffs or tariff components (for example, introducing a step rate for the usage component of the domestic tariff)
- adjustments to existing tariffs or tariff components (for example, changing the threshold on an inclining block tariff or the time bands associated with time of use tariffs). This situation is essentially the same as introducing new tariffs or tariff components.
- when customers move between existing tariffs (from origin tariffs to alternative tariffs).

The weighted average price cap (WAPC) and side constraint formulas applying to the control mechanism will require adjustments for those tariffs subject to a change in structure. Specifically, adjustments will be required to:

- the historical quantity weights (q_{ik}^{t-2} and q_{k}^{t-2}) for these tariffs and
- the values of the current tariffs/tariff components in the WAPC and side constraint formulas (p_{ik}^{t-1} and d_{k}^{t-1}).

This appendix sets out the approach to estimating the historical quantity weights and the substitute values for the current tariffs/tariff components to be used when calculating compliance with the WAPC and the side constraint formulas. For simplicity of presentation, any discussion in this appendix in relation to p_{ik}^{t-1} and q_{ik}^{t-2} should be taken to be equally applicable to d_{k}^{t-1} and q_{k}^{t-2}.

J.1 Introducing new tariffs or tariff components

The value of q_{ik}^{t-2}

Both the WAPC and side constraint are calculated using audited historical quantities of consumption. However, historical quantities for any new tariffs/tariff components will not be available for two years.

In order to incorporate new tariff structures in the WAPC and the side constraint, the AER requires reasonable estimates to be submitted by the DNSP, based on the quantities that would have been sold, if the new tariff/tariff components have been introduced in year ‘t–2’. The AER has adopted the following process, which was developed by IPART, in order for the DNSP to arrive at these estimates.

First, the DNSP must nominate the origin tariffs/tariff components, which represent the tariffs/tariff components that the customers, who will be moved to the new network tariffs/tariff components, are currently being charged.

Second, the DNSP must provide reasonable estimates of q_{ik}^{t-2} for all applicable units of measure (e.g. kWh, kW) for both the new tariffs/tariff components, and the origin tariffs/tariff components. The DNSP must make the following assumptions when calculating these reasonable estimates:

1. The only customers who would have moved to the new network tariff/tariff component in year 't–2' did so due to a change in tariff structures initiated by the DNSP and as permitted under the customers' standard network connection contract.[1259] This means that no new customers are included in the estimate,[1260] and nor are customers who request to change tariff either voluntarily, or through the actions of a retailer.
2. Customers have the same consumption and load profile on the new tariff/tariff component as they did on the origin tariff/tariff component. This implies that the sum of the reasonable estimates for year 't–2' for each unit of measure on the new tariff/tariff component plus the reasonable estimates for year 't–2' for each unit of measure on the origin tariff/tariff component, equals the actual audited quantities that occurred for the origin tariff/tariff component in year 't–2'.

In the year after a new tariff/tariff component has been introduced, there will still be no full year of audited historical data available to be used for q_{ik}^{t-2}. As a result the DNSP will be required to again submit reasonable estimates for both the new tariff/tariff component and the corresponding origin tariff/tariff component. At this time, however, the DNSP may base the reasonable estimates on the actual quantities that have occurred to date on the new tariff/tariff components and origin tariff/tariff components. The DNSP must demonstrate how it has arrived at the estimates.

The value of p_{ik}^{t-1}

The p_{ik}^{t-1} of the corresponding origin tariff/tariff components will be used as the p_{ik}^{t-1} for the new tariff/tariff components, where both the origin and new tariff components are measured in the same units of measure. If there is no corresponding origin tariff/tariff components with the same units of measure, p_{ik}^{t-1} will be set to zero.

Example 1: Introducing a step rate or inclining block tariff component

This example assumes that a domestic tariff with a single variable rate is amended so that there are now two variable rates based on a customer's level of consumption. For each of the 25 000 customers on this tariff, their historical consumption is split between consumption up to 5000kWh per annum and any residual consumption above this amount. Under this approach, the total consumption for this tariff class of 200 000MWh is split, 150 000MWh against variable rate 1 and 50 000MWh against variable rate 2 as shown in the example set out in table J.1.

[1259] Each customer has a standard network connection contract with its DNSP and a separate contract with its respective retailer who manages the relationship with the DNSP on the customer's behalf.
[1260] New customers have been allowed for in the growth assumption used when setting the X factor.

Table J.1: Determining p_{ik}^{t-1} and q_{ik}^{t-1} in Example 1

Tariff reform		p_{ik}^{t-1}	q_{ik}^{t-2}
Origin tariff – standard domestic			
Fixed charge	$ pa per customer	30	25 000 customers
Variable rate (all consumption)	c/kWh	0.04	200 000MWh
Proposed tariff with new component			
Fixed charge	$ pa per customer	30	25 000 customers
Variable rate 1 (consumption ≤ 5000kWh pa per customer)	c/kWh	0.04 (as per origin tariff)	150 000MWh
Variable rate 2 (consumption > 5000kWh pa per customer)	c/KWh	0.04 (as per origin tariff)	(200 000 –150 000) = 50 000MWh

Note: While the variable rates (1 & 2) that the DNSP proposes for the next year (p_{ik}^{t}) are likely to differ, the divergence in these rates is constrained by the overall WAPC and the side constraints for this tariff class.

J.2 Customers transferred by the DNSP to an alternative tariff

The value of q_{ik}^{t-2}

If the DNSP proposes to move a number of customers across to an alternative existing tariff,[1261] the rate at which revenue will accrue from these customers will be different to what was used to calculate the X factor and will be different to what will be calculated under the WAPC formula. In addition, the side constraint formula will not fully reflect the actual tariff change for the customers being transferred, as the overall tariff change observed by these customers will reflect not only the side constraint on the alternative tariff but the difference between the origin tariff the customer was on and the alternative tariff they are being transferred to. In these circumstances, the AER will require the DNSP to submit reasonable estimates for q_{ik}^{t-2} for each origin tariff that the customer is currently on, and the new tariff that the DNSP will move the customers to, taking the transfer into account.

For compliance purposes, the assumptions the DNSP must make when calculating the reasonable estimates are:

[1261] The DNSP may decide to transfer customers if a customer's consumption or load profile has changed and the DNSP decides it is no longer appropriate for them to remain on the same tariff. Alternatively the DNSP may change the structure of an existing tariff to suit the majority of customers. Appendix A sets out the procedures a DNSP must adhere to in assigning or reassigning customers to tariff classes.

1. The customer movement occurred in year ‘t–2’.
2. The customers only moved as a result of a change in tariff structures initiated by the DNSP and as permitted under the customers’ standard network connection contract. The estimates are not to include customers who choose to move at their discretion or movements caused by a retailer’s action.
3. Customers have the same consumption and load profile under either tariff.

Reasonable estimates will also be required in the year following the movement as there will still be no full year of audited historical data available.

The value of p_{ik}^{t-1}

As for the introduction of new tariffs/tariff components, the p_{ik}^{t-1} for the corresponding origin tariff components will be used as the p_{ik}^{t-1} for the new tariff components.[1262]

Example 2: Re-assigning some customers from the domestic flat rate tariff to the domestic TOU tariff

The example in table J.2 assumes 10 000 customers with consumption of 70 000MWh will be moved by the DNSP from the domestic tariff to the domestic TOU tariff. Both tariffs remain in existence and there will be customers on both. The allocation of the 70 000MWh across the peak, shoulder and off–peak reflect historical consumption patterns.

[1262] This approach is only needed for movements that occur in Year t, not for movements in Year ‘t–1’ as any customers that were moved in Year ‘t–1’ will already be on the alternative tariffs.

Table J.2: Determining p_{ik}^{t-1} and q_{ik}^{t-2} in Example 2

Tariffs		p_{ik}^{t-1}	q_{ik}^{t-2}
Domestic			
Fixed charge	$ pa per customer	30	(25 000 existing – 10 000) = 15 000 customers
Variable rate (any time)	c/kWh	0.04	(200 000 existing – 70 000) = 130 000 MWh
Domestic TOU – existing customers			
Fixed charge	$ pa per customer	22	5000 existing
Peak rate	c/kWh	0.09	10 000MWh existing
Shoulder rate	c/kWh	0.05	10 000MWh existing
Off-peak rate	c/kWh	0.02	10 000MWh existing
Domestic TOU – customers being transferred			
Fixed charge	$ pa per customer	30 (as per domestic)	10 000 customers
Peak rate	c/kWh	0.04 (as per domestic)	25 000MWh
Shoulder rate	c/kWh	0.04 (as per domestic)	20 000MWh
Off-peak rate	c/kWh	0.04 (as per domestic)	25 000MWh

Note: The Domestic TOU tariff the DNSP proposes for next year (p_{ik}^{t}) will apply equally across all (15 000) customers now on that tariff, which must be within the constraints of the WAPC and side constraints.

J.3 AER assessment of reasonable estimates

When assessing the reasonableness of quantity estimates provided by a NSW DNSP, the AER will take the following information into account:

1. the actual audited quantities sold in relevant units under the origin tariff in previous years

2. a forecast of the number of distribution customers that the DNSP states will move to the new tariff/tariff components, and the reasons for the move

3. a forecast of the number of distribution customers that the DNSP expects will remain on the origin tariff

4. a forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that are to be moved to the new tariff/tariff components

5. a forecast of the quantities that the DNSP expects will be sold, in relevant units, to those distribution customers that will remain on the origin tariff

6. a forecast of the distribution tariff, and associated revenue, the DNSP expects will be payable by those distribution customers that will be moved to the new tariff/tariff components

7. a forecast of the distribution tariff, and associated revenue, the DNSP expects will be payable by those distribution customers that will remain on the origin tariff

8. the approach the DNSP used to determine its forecasts (for 2–7 above)

9. the materiality of the reasonable estimates

10. further information as required by the AER.

Appendix K: D–factor reporting and setting of D–factors

The AER will apply the D–factor scheme to the NSW DNSPs as part of its demand management incentive scheme (DMIS) over the next regulatory control period, in the form applied by IPART in the current regulatory control period.

The AER requires the NSW DNSPs to follow the same reporting requirements as stated within clause 11.1 of IPART's 2004 final determination, and the same assessment and approval process outlined in clause 11.2 of IPART's 2004 final determination.[1263] In calculating the annual D–factor adjustment to the weighted average price cap (WAPC) and side constraint formulas, the AER will follow the processes outlined in clauses 11.3, 11.4 and 11.5 of IPART's 2004 final determination.[1264]

This appendix reproduces the clauses on calculating the D–factor within IPART's 2004 final determination. Some of the terms used by IPART need to be redefined for application in the next regulatory control period. Accordingly, this chapter outlines how IPART's 2004 final determination clause 11 is to be interpreted in the context of the next regulatory control period, including a list of definitions.

K.1 Clause 11 of IPART's 2004 final determination

Clause 11 of IPART's 2004 final determination is reproduced below.

[1263] IPART, *NSW Electricity distribution pricing*, pp. 18–19.
[1264] IPART, *NSW Electricity distribution pricing*, pp. 19–21.

11 Demand management reporting and the setting of "D" factors

11.1 Annual submission of demand management information

On or before the first of February immediately prior to submitting its Annual Pricing Proposal to the Tribunal for each Year of the Regulatory Control Period under clause 12 (the Year *t+1* for the purposes of this clause 11), each DNSP must submit to the Tribunal the following information:

(a) a detailed description of any Non-Tariff Demand Management Measures, undertaken by the DNSP during the Year *t-1* including (for each measure) its characteristics, the capital expenditure and operating costs to be deferred as a result of the measure and any reasonable alternatives to the measure;

(b) the DNSP's Non-Tariff Demand Management Costs for the Year *t-1*;

(c) a detailed description of any Tariff Demand Management Measures undertaken by the DNSP during the Year *t-1*, demonstrating (for each measure) that the objective of the Network Tariff change (for that measure) is to affect the behaviour of end use Distribution Customers;

(d) the DNSP's Tariff Demand Management Costs for the Year *t-1*, demonstrating:

 (1) the nature of those costs and their efficiency;

 (2) that the expenditure of those costs is necessary to achieve the objective of the Network Tariff change;

(e) reasonable estimates of each of the following:

 (1) the DNSP's Foregone Revenue for the Year *t-1,* resulting from the Non-Tariff Demand Management Measures referred to in clause 11.1(a) and from any such measures occurring in any prior Years of the Regulatory Control Period*;* and

 (2) the DNSP's Avoided Distribution Costs resulting from each of those measures*;*

(f) details of the basis for those estimates (including any assumptions underlying them) and demonstrating that the methodology used to calculate Foregone Revenue does give rise to a reasonable estimate of the actual amount of Foregone Revenue and is consistent with any guideline published by the Tribunal from time to time;

(g) an estimated amount to reflect the time value of money, calculated by multiplying the following:

 (1) the sum of the costs and foregone revenue referred to in clauses 11.1(b), (d) and (e)(1);

 (2) the Nominal Rate of Return; and

 (3) the number of years (or part thereof) between the incurring of those amounts and the commencement of the Year *t+1*; and

(h) any other information the Tribunal may require in relation to the matters referred to in this clause 11.1.

11.2 Assessment and approval by the Tribunal

(a) The Tribunal will assess whether the Non-Tariff Demand Management Costs and the Tariff Demand Management Costs submitted by a DNSP under this clause 11 are reasonable, having regard (without limitation) to:

(1) the information provided by the DNSP under this clause 11; and

(2) whether the Tribunal considers the expenditure of those costs was efficient.

(b) The Tribunal will assess whether the estimates of Foregone Revenue and Avoided Distribution Costs submitted by a DNSP under this clause 11 and the estimated amount submitted under clause 11.1(g) are reasonable, having regard (without limitation) to the information provided by the DNSP under this clause 11.

(c) If the Tribunal considers that a cost or estimate provided under this clause 11 is incomplete, inconsistent or unsubstantiated in any way, then the Tribunal may request additional information or request that the DNSP revise and resubmit that cost or estimate.

(d) If the Tribunal considers that the costs and estimates provided under this clause 11 are reasonable it will approve them by notice in writing issued to the DNSP.

(e) If the Tribunal considers that any of the costs or estimates provided under this clause 11 are unreasonable then the Tribunal may approve (at its own discretion) alternative costs or alternative estimates (as the case may be) for the purposes of this clause 11.2.

11.3 Calculation of D-factors

For the purposes of complying with the weighted average price control formula in clause 5.2, each DNSP must calculate D_{t+1} (for the Year *t+1*) referred to in that formula as follows (rounded to 3 decimal places):

$$D_{t+1} = \frac{\text{DM Cost Pass Through Amount}_{t+1}}{\text{SRR}_{t}\text{-AF Revenue}_{t-1}} - \frac{\text{DM Cost Pass Through Amount}_{t}}{\text{SRR}_{t-1}\text{-AF Revenue}_{t-2}}$$

where:

DM Cost Pass Through Amount $_{t+1}$ is the DM Cost Pass Through Amount for the DNSP for the Year *t+1,* calculated in accordance with clause 11.4;

DM Cost Pass Through Amount $_{t}$ is the DM Cost Pass Through Amount for the DNSP for the Year *t,* calculated in accordance with clause 11.4 (when the Year *t* was the Year *t+1* for the purposes of clause 11.4);

SRR_t is the smoothed revenue requirement for the DNSP for the Year *t*, as set out in **Annexure 12**;

SRR_{t-1} is the smoothed revenue requirement for the DNSP for the Year *t-1,* as set out in **Annexure 12**;

AF Revenue $_{t-1}$ is the estimate of the DNSP's Foregone Revenue for the Year *t-1* approved by the Tribunal under clause 11.2;

AF Revenue $_{t-2}$ is the estimate of the DNSP's Foregone Revenue for the Year *t-2* approved by the Tribunal under clause 11.2 (when the Year *t-2* was the Year *t-1*, for the purposes of clauses 11.1 and 11.2).

11.4 Calculation of DM Cost Pass Through Amounts

Subject to clause 11.5, the DM Cost Pass Through Amount for the Year *t+1* for each DNSP (for the purposes of clause 11.3) will be calculated by adding together each of the following amounts (provided that the Year *t-1*, wherever referred to below, must be a Year falling within the Regulatory Control Period):

(a) the amount of the DNSP's Non-Tariff Demand Management Costs for the Year *t-1* as approved by the Tribunal under clause 11.2;

(b) the amount of the DNSP's Tariff Demand Management Costs for the Year *t-1* as approved by the Tribunal under clause 11.2;

(c) the amount of the estimate of the DNSP's Foregone Revenue for the Year *t-1* as approved by the Tribunal under clause 11.2;

(d) the estimated amount for the purposes of clause 11.1(g) for the Year *t-1* as approved by the Tribunal under clause 11.2; and

(e) any DM Cost Pass Through Amount for the Year *t* deferred to the Year *t+1* under clause 11.5 (when the Year *t* was the Year *t+1* for the purposes of clause 11.5).

11.5 Deferral of Cost Pass Through Amounts

(a) Subject to an adjustment under clause 11.5(b) and except where the Year *t+1* is the last Year of the Regulatory Control Period, a DNSP may defer its DM Cost Pass Through Amount for the Year *t+1* (as calculated under clause 11.4) to the immediately following Year, if:

$$\frac{\text{DM Cost Pass Through Amount}_{t+1}}{\text{SRR}_t - \text{AF Revenue}_{t-1}} < 0.001$$

Where:

DM Cost Pass Through Amount $_{t+1}$ is the DM Cost Pass Through Amount for the DNSP for the Year *t+1,* calculated in accordance with clause 11.4;

SRR_t is the smoothed revenue requirement for the DNSP for the Year *t*, as set out in **Annexure 12**;

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AF Revenue $_{t-1}$	is the estimate of the DNSP's Foregone Revenue for the Year *t-1* approved by the Tribunal under 11.2.

(b) The amount of any DM Cost Pass Through Amount for the Year *t+1* that is deferred to the immediately following Year under clause 11.5(a) must be adjusted by multiplying it by the sum of:

1 + the Nominal Rate of Return.

(c) If a DNSP does defer its DM Cost Pass Through Amount for the Year *t+1* in accordance with this clause, then when calculating D_{t+1} for the DNSP for the Year *t+1* under clause 11.3, the value of "DM Cost Pass Through Amount$_{t+1}$" must be taken to be zero.

K.2 Interpreting clause 11 of IPART's 2004 final determination

References to the Tribunal

For the purposes of calculating the D–factor for the NSW DNSPs in the next regulatory control period, where clause 11 of IPART's final determination refers to 'the Tribunal' this term is to be read as 'the AER'.

Cross references within clauses

Where clause 11 of IPART's 2004 final determination refers to other clauses within IPART's 2004 final determination, these references should be read as referring to equivalent sections of the AER's final decision.

Temporal definitions

For the purpose of the AER's final decision and distribution determinations for the NSW DNSPs for the next regulatory control period, the AER has defined the current regulatory year as 'year t–1' whereas IPART defined it as 'year t'. Also, the AER defines the next regulatory year as 'year t' whereas IPART defined it as 'year t+1'.

When referring to or reproducing clause 11 of IPART's 2004 final determination, the AER's final decision and distribution determinations must be read in the context of these temporal definitions.

Example

For example, clause 11.1 of IPART's 2004 final determination states:

> On or before the first of February immediately prior to submitting its Annual Pricing Proposal to the Tribunal for each Year of the Regulatory Control Period under clause 12 (the Year t+1 for the purposes of this clause 11), each DNSP must submit to the Tribunal the following information...

which, for the purposes of calculating the D–factor in the next regulatory control period, is to be read as:

> On or before the first of February immediately prior to submitting its Annual Pricing Proposal to the AER for each year of the Regulatory Control Period under the AER's methodology and process for setting annual prices (the year t for the purposes of this appendix K), each DNSP must submit to the AER the following information…

Terms defined by IPART

There are various terms within IPART's clause 11, reproduced above, which are defined in Annexure 1 of IPART's 2004 final determination, and not defined within the NER or used in other parts of this final decision.[1265] The AER has adopted the following definitions of these terms for the purposes of calculating the D–factor for the next regulatory control period:

- **Annual pricing proposal** means an annual pricing proposal submitted by a NSW DNSP in accordance with the AER's methodology and process for setting annual prices for network tariffs.
- **Avoided distribution costs** resulting from a NSW DNSP's non–tariff demand management measures for a year means the expected change in the present value of the NSW DNSP's operating costs and capex resulting from the deferral or postponement (temporarily or indefinitely) of expenditure on the NSW DNSP's distribution system as a result of those measures.
- **Foregone revenue** of a NSW DNSP for any year means any revenue (from prescribed distribution services provided by the NSW DNSP) which:
  - has not been recovered by the NSW DNSP in that year; and
  - would in all likelihood have been recovered by the NSW DNSP in that year, but for the non–tariff demand management measures undertaken by or on behalf of that NSW DNSP.
- **Incremental costs** incurred by a NSW DNSP in relation to any tariff demand management measure or non–tariff demand management measure means any additional opex or capex incurred by the DNSP (based on audited expenditure data) as the sole consequence of that measure and which have not already been taken into account by the AER in the setting of the X factors for the NSW DNSPs, as set out in chapter 16 of this final decision.
- **Network tariff** means a charge, tariff or fee charged (or rebate allowed) by a NSW DNSP to a distribution customer in relation to providing distribution use of system (DUOS) services or any other prescribed distribution services (other than monopoly services, miscellaneous services or emergency recoverable works) to or for that customer and which comprises two separate tariffs, namely:
  - a DUOS tariff
  - a transmission cost recovery tariff (incurred for transmission use of system services).
- **Non–tariff demand management costs** for any year means the incremental costs incurred by a NSW DNSP in that year in relation to the non–tariff demand management measures undertaken by it in that year or in any prior year of the regulatory control period, subject to:

[1265] IPART, *NSW Electricity distribution pricing*, pp. 32–44.

  - the exclusion of any costs incurred by the NSW DNSP to the extent that they have been funded by a government or by any person other than the NSW DNSP (or a person, other than a government, related to the NSW DNSP), or funded under the AER's demand management innovation allowance
  - the exclusion of any costs incurred by the NSW DNSP in relation to the installation of capacitors or load control equipment or infrastructure or any other costs associated with activities that the AER has already taken into account in determining the NSW DNSP's X factors, as set out in chapter 16 of this final decision
  - for each non–tariff demand management measure, the present value of the total amount of all costs incurred in relation to that measure must not exceed the avoided distribution costs resulting from that measure, as approved by the AER.
- **Non–tariff demand management measures** means any action, project or activity undertaken by or on behalf of a NSW DNSP, either independently or in conjunction with any other persons (such as generators, retail suppliers, energy service intermediaries and end-use customers), with the objective of reducing the costs of providing prescribed distribution services by altering the level or pattern of consumption of energy, the source of energy, or the use of the NSW DNSP's distribution system, but excluding:
  - tariff demand management measures
  - any activities which expand the distribution system or its capacity or which renew, repair or maintain it.
- **Prescribed distribution services** means standard control services, as defined in chapter 2 of this final decision.
- **Present value** of any cost or expenditure of a NSW DNSP means the present value of that cost or expenditure calculated using a discount rate equivalent to the rate of return, set out in chapter 11 of this final decision.
- **Regulatory control period** in the context of clause 11 of IPART's 2004 final determination means the next regulatory control period from 1 July 2009 to 30 June 2014.
- **Smoothed revenue requirement** means the expected revenue for a particular regulatory year, as calculated by the AER in this final decision at table 16.23 for Country Energy, table 16.27 for EnergyAustralia and table 16.30 for Integral Energy.
- **Tariff demand management costs** for any year means the incremental costs incurred by a NSW DNSP in that year (as part of its tariff demand management measures undertaken in that year or in any prior year of the regulatory control period) in installing equipment at a distribution customer's premises so as to control the time at which electricity is consumed at, or supplied to, the premises, but excluding:
  - metering costs
  - any costs incurred by the NSW DNSP in developing or offering to distribution customers the changes made to the network tariffs the subject of its tariff demand management measures

- any costs incurred by the NSW DNSP to the extent that they have been funded by a government or by any person other than the NSW DNSP (or a person, other than a government, related to the NSW DNSP), or funded under the AER's DMIA
- any costs associated with activities the AER has already taken into account in determining the NSW DNSPs' X factors, as set out in chapter 16 of this final decision.

- **Tariff demand management measures** means the introduction by a NSW DNSP of new tariff components with the objective of reducing the costs of providing prescribed distribution services by altering the level or pattern of consumption or energy, the source of energy, or the use of the distribution system.
- **Year** means any financial year, commencing on 1 July and ending on 30 June.

Appendix L: 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.

L.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.[1266] This involves the disaggregation of expenditure allowances into specific inputs (e.g. labour, land and materials) which are priced in terms of a base year. These base year costs are increased or decreased for each year of the regulatory control period relative to changes in the nominal price level, which is taken into account when prices and revenues are adjusted at the aggregated level under the CPI–X control mechanism.

The methodology employed to determine the cost escalators generally combines independent forecast movements in the price of input components with 'weightings' for the relative contribution of each of the components to final equipment/project costs. This in turn generates real capex and opex forecasts for the regulatory control period. The weightings are typically specific to each regulated business given differences in composition of their respective expenditure forecasts.

The underlying objective of real cost escalations was to take account of the commodities boom and skills shortages in the engineering field in Australia. In light of these external factors, it was considered that cost escalation at CPI no longer reasonably reflected a realistic expectation of the movement in some of the equipment and labour costs faced by electricity network service providers (NSPs).[1267] 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.[1268] 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

[1266] AER, *Powerlink revenue cap decision*, pp. 60–70; AER, *Draft Decision – SP AusNet transmission determination 2008–09 to 2013–14*, 31 August 2007, pp. 87–91, 316–331; and AER, *Final Decision – ElectraNet transmission determination 2008–09 to 2012–13*, 11 April 2008, pp. 29–48.

[1267] NER, transitional chapter 6 rules, clause 6.5.7(c)(3).

[1268] AER, *Final Decision – SP AusNet transmission determination 2008–09 to 2013–14*, January 2008, p. 80.

- land/easement costs.

Other inputs (such as steel) were escalated at CPI.

L.2 AER draft decision

In assessing the escalators recommended by CEG and used by the NSW DNSPs, 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.[1269]

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 6.5.7(c) of the transitional chapter 6 rules.[1270]

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 escalation 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.[1271]

In the draft decision the AER stated that it would update its escalators closer to the time of the release of its final decision.[1272]

L.3 Revised regulatory proposals

The NSW DNSPs did not accept the materials cost escalators applied by the AER in the draft decision. They engaged CEG[1273] to review the draft decision and, based on that advice, determined that while the AER's approach was largely reasonable, they had concerns with the AER's:[1274]

- modelling, principally timing and the application of lags
- proposed approach to updating labour cost escalation factors.

The NSW DNSPs accepted the cost escalator for land specified in the draft decision. Revised escalators were, however, proposed for the majority of the other cost escalators.

[1269] AER, *Draft decision*, pp. 531–532.
[1270] AER, *Draft decision*, p. 532.
[1271] AER, *Draft decision*, p. 532.
[1272] AER, *Draft decision*, p. 532.
[1273] CEG, *Escalations affecting expenditure forecasts*.
[1274] CEG, *Escalations affecting expenditure forecasts*, p. 2.

L.4 Non–labour cost escalators—aluminium, copper, steel and crude oil

L.4.1 AER draft decision

Taking into account the methodology it had developed for the ElectraNet decision[1275], the AER rejected the NSW DNSPs' materials cost escalators.[1276] The AER applied the materials cost escalators set out in table L.1 for the next regulatory control period.

Table L.1: AER 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. 549, 552–554.

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)[1277]—see section L.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:[1278]

- 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. Due to the high volatility of the data, the AER used a centred moving average to account for prices for each month.[1279]

[1275] AER, *Final decision, ElectraNet transmission determination 2008–09 to 2012–13,* 11 April 2008.
[1276] AER, *Draft decision*, pp. 543–564.
[1277] AER, *Draft decision*, pp. 546–548.
[1278] AER, *Draft decision*, pp. 549–542.
[1279] AER, *Draft decision*, pp. 553–554.

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 the materials component of capex.[1280]

L.4.2 Revised regulatory proposals

The NSW DNSPs 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 and lag adjustment had not been appropriately taken into account.[1281]

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.[1282]

The NSW DNSPs accepted CEG's findings and proposed revised escalators for materials—see tables L.2, L.3 and L.4.

Table L.2: Country Energy 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	–15.9	5.3	7.6	6.6	3.5	–0.8	–1.1
Copper	–6.7	–14.8	–4.1	7.1	5.6	–6.0	–6.4
Steel	5.8	42.9	–8.2	2.1	–3.8	–4.7	–5.0
Crude oil	29.4	–0.2	0.9	6.8	2.9	0.3	–1.0

Source: CEG, *Escalators affecting expenditure forecasts*, p. 20.

Table L.3: EnergyAustralia 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	–7.9	–5.4	6.9	5.9	7.4	–0.1	–0.9
Copper	–15.0	–5.1	–13.7	0.0	14.9	–4.4	–6.2
Steel	–13.9	50.0	1.8	–0.5	–1.2	–4.6	–4.9
Crude oil	–7.4	33.2	–12.5	9.7	4.9	1.3	–0.4

Source: CEG, *Escalators affecting expenditure forecasts*, p. 22.

[1280] AER, *Draft decision*, pp. 561–564.
[1281] CEG, *Escalations affecting expenditure forecasts*, pp. 3–7, 17–19.
[1282] CEG, *Escalations affecting expenditure forecasts*, pp. 3–6.

Table L.4: Integral Energy 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	–8.6	5.3	7.6	6.6	3.5	–0.8	–1.1
Copper	–4.3	–14.8	–4.1	7.1	5.6	–6.0	–6.4
Steel	12.0	42.9	–8.2	2.1	–3.8	–4.7	–5.0
Crude oil	25.5	–0.2	0.9	6.8	2.9	0.3	–1.0

Source: CEG, *Escalators affecting expenditure forecasts*, p. 22.

L.4.3 Submissions

The Energy Users Association of Australia (EUAA) noted a changed 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.[1283] 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.[1284]

The Energy Market Reform Forum (EMRF) noted that the AER needed to revise its materials price escalators as they were out of date, given the impact of the world economy (including the Australian economy) on materials.[1285]

Origin Energy noted that the economic outlook had changed considerably from when the DSNP's had developed their escalators and that economic data was pointing to reduced materials costs.[1286]

L.4.4 AER considerations

Base period adjustment

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.[1287] 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.

[1283] EUAA, p. 16.
[1284] EUAA, p. 17.
[1285] EMRF, pp. 16–19.
[1286] Origin Energy, p. 5.
[1287] This averaging period is centred on December as proposed by CEG as it is reflective of price movements over the entire 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 the NSP's base costs were calculated. For EnergyAustralia this period is December 2006, for Country Energy this is the financial year 2006–07 and for Integral Energy this is December 2007.

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 EnergyAustralia, Country Energy and Integral Energy to reflect the base cost period of December 2006, financial year 2006–07 and December 2007 (respectively) for each period of the next regulatory control period.

Adjustment lag

In the draft decision, the AER examined the material provided by EnergyAustralia and concluded that there was not sufficient evidence to support the application of a lag between commodity price changes and equipment costs for it or for any other DNSP.[1288]

In the material provided to support the NSW DNSPs' revised regulatory proposals, the AER notes CEG's concerns regarding the rejection of the use of lags when applying materials costs to the NSW DNSPs' capex programs. CEG's concerns included:

- the draft decision did not provide any new or relevant information on which to revise the precedent that it established in the ElectraNet determination, where a lag was accepted[1289]
- the PPIs used by the AER in the draft decision reflected the prices of intermediate goods rather than the equipment being purchased by the NSW DNSPs. Thus, any lag evident would not reflect the full amount of time it takes for commodity prices changes to flow through to final equipment prices.[1290]

The AER recognises that in the draft decision for SP AusNet, it considered it reasonable to allow a lag of 12 months for commodity prices movements to flow through to the cost of electrical equipment faced by SP AusNet. This conclusion was based on a visual observation of commodity prices and producer price indices.[1291] This approach followed the approach adopted by SKM, which conducted the analysis for SP AusNet supporting its proposal for a 24 month lag.[1292] The AER also recognises that following the SP AusNet draft decision, ElectraNet proposed a lag of 12 months, which the AER also accepted.[1293]

The AER considers that the concerns raised by CEG regarding the analysis in the draft decision, which was limited to a visual analysis of raw material prices and producer price indices have some merit.[1294] Having reconsidered the approach it adopted in the draft

[1288] AER, *Draft decision*, p. 564.

[1289] CEG, *Escalators affecting expenditure forecasts*, p. 18. The AER notes that in the draft decision for ElectraNet the AER accepted the 12 month lag proposed by it on the basis of the analysis conducted for the SP AusNet draft decision (pp. 320–323), where it also accepted a 12 month lag. Source: AER, *ElectraNet, Draft decision*, p. 100.

[1290] CEG, *Escalators affecting expenditure forecasts*, p. 19.

[1291] AER, *SP AusNet Draft decision*, pp. 320–323.

[1292] SKM, *Escalation factors affecting capital expenditure forecasts*, 21 February 2007, pp. 14–16.

[1293] AER, *Draft decision: ElectraNet transmission determination 2008–09 to 2012–13*, 9 November 2007, p. 100.

[1294] CEG, *Escalators affecting expenditure forecasts*, p. 18.

decision, and in previous decisions, the AER considers that the analysis of lags it conducted was not sufficiently robust.

The AER considers that the analysis undertaken did not demonstrate, to a reasonable level, the potential relationship between commodity prices and electrical equipment prices. Furthermore, this analysis did not explore the potential impact of other factors, such as other cost inputs and economic conditions, on electrical equipment prices. The AER also notes that the NSW DNSPs have not provided any new and reasonable evidence in their regulatory proposals to support the suggestion that movement of commodity prices systematically flows through to final goods prices.

The AER notes that EnergyAustralia, as part of its revised regulatory proposal, provided example electrical equipment contracts to support its positions on lags.[1295] However, the lags inherent in the pricing arrangements of each of these contracts varied but were six months or less in each instance. The AER considers that the example contracts provided do not support the application of a six months lag for all equipment purchased by EnergyAustralia. Rather, the AER considers that the example contracts provided indicate that equipment prices and commodity prices have been closely aligned but this does not mean that there is a causal relationship.

In the absence of any robust evidence supporting the application of a lag of six months, the AER considers that the application of a six month lag when calculating materials cost escalators, as recommended by CEG and adopted by the NSW DNSPs, does not provide a realistic expectation of the cost inputs required to achieve the capital expenditure objectives.

The AER also notes that in their initial regulatory proposals, Country Energy and Integral Energy did not apply a lag as recommended by CEG. However, in the material provided to support their revised regulatory proposals this approach changed. Specifically, Country Energy and Integral Energy assumed a lag of six months for the copper, aluminium, steel and oil cost escalators.[1296]

The AER considers that the information presented by Country Energy and Integral Energy represents new information that differs from the information contained in their regulatory proposals. The AER notes that this change was not made to address matters raised in the draft decision and that as a result, under the NER, this change can not be accepted.[1297]

The AER therefore maintains the position it took in the draft decision that the reasonableness of the application of lags in the cost estimating process has not been demonstrated by any of the NSW DNSPs.

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 three month LME contract price, the 15 month LME contract

[1295] EnergyAustralia, *Revised regulatory proposal,* Attachment 3F, confidential, December 2008.
[1296] CEG, *Escalators affecting expenditure forecasts*, p. 19.
[1297] NER, transitional chapter 6 rules, clause 6.5.7(c)(3).

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.

The AER also identified that with Country Energy and Integral Energy having accepted CEG's use of a centred moving average for each series that they should have used the escalators detailed under the 'December to December' table submitted with the revised regulatory proposals. The AER notes that the 'December to December' escalators in CEG's second report are comparable to the 'June to June' escalators applied in the draft decision. Use of CEG's December to December escalators will result in escalators that are representative of the costs that a DNSP would incur during a financial year. The AER engaged with Country Energy and Integral Energy to clarify this issue and obtain agreement about which escalators should be applied in their modelling.

The AER's conclusions on materials cost escalations are set out in tables L.5, L.6 and L.7.

Table L.5: AER conclusions on Country Energy'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	–16.13	–17.34	–14.06	9.13	10.55	10.93	9.32
Copper	–6.93	–27.93	–10.83	2.06	2.46	2.32	1.96
Steel	5.57	16.27	–15.32	7.21	5.25	1.03	0.76
Crude oil	28.58	–18.33	–5.19	10.24	5.74	2.16	1.30

Table L.6: AER conclusions on EnergyAustralia'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	–19.83	–17.34	–14.06	9.13	10.55	10.93	9.32
Copper	–1.31	–27.93	–10.83	2.06	2.46	2.32	1.96
Steel	12.40	16.27	–15.32	7.21	5.25	1.03	0.76
Crude oil	31.54	–18.33	–5.19	10.24	5.74	2.16	1.30

Table L.7: AER conclusions on Integral Energy'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	–	–10.19	–14.06	9.13	10.55	10.93	9.32
Copper	–	–17.35	–10.83	2.06	2.46	2.32	1.96
Steel	–	36.24	–15.32	7.21	5.25	1.03	0.76
Crude oil	–	–16.73	–5.19	10.24	5.74	2.16	1.30

L.5 EGW wages and general wages

L.5.1 AER draft decision

In the draft decision, the AER engaged Econtech to provide advice on labour cost growth forecasts in NSW. 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 the NSW DNSPs' proposal, which was based on advice from CEG, to apply an average of Econtech (published in 2007) and Macromonitor EGW labour costs growth forecasts.[1298]

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, in order for the AER to make an assessment.[1299]

The AER considered that Econtech's general labour cost growth forecasts are appropriate to escalate direct labour costs (i.e. other than EGW) incurred by the NSW DNSPs. The AER, however, did not accept the general wage forecasts applied by the NSW DNSPs 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.[1300]

The AER's draft conclusions for the NSW DNSPs' EGW and general labour forecasts are set out in table L.8.

[1298] AER, *Draft decision*, p. 537.
[1299] AER, *Draft decision*, p. 541.
[1300] Econtech, *Updated labour costs growth forecasts*, p. 38 and AER, *Draft decision*, p. 541.

Table L.8: AER draft conclusions for NSW DNSPs EGW and general labour forecasts (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14	Average
EGW wages	–1.4[a] 1.4[b] 1.5[c]	2.8	3.9	3.4	3.0	2.8	2.1	1.0
General labour	0.6	1.0	1.1	0.7	0.7	0.8	0.6	0.8

Source: AER, *Draft decision*, pp. 539, 541.
(a) Country Energy
(b) EnergyAustralia
(c) Integral Energy

L.5.2 Revised regulatory proposal

NSW DNSPs

The NSW DNSPs did not accept the EGW wages and general labour escalators applied by the AER in the draft decision. The NSW DNSPs 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 the NSW DNSPs.

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.[1301] These reports include:

- Forecasts of Cost Indicators for the Electricity Transmission Sector – New South Wales and 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.[1302]

CEG stated Econtech has made clear it did not adjust its labour cost forecasts for productivity.[1303] CEG also considered that the AER, in accepting Econtech's forecasts,

[1301] CEG, *Escalators affecting expenditure forecasts*, p. 27.
[1302] CEG, *Escalators affecting expenditure forecasts*, pp. 28–29.
[1303] CEG, *Escalators affecting expenditure forecasts*, p. 33.

has implicitly accepted that forecast wages growth should not be adjusted for productivity growth.

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 the NSW DNSPs adopt the AER's forecasts in their revised regulatory proposals.[1304]

Application of EGW wage and general labour escalators

CEG raised issues with applying updated Econtech EGW and general labour escalators after the businesses had lodged their revised regulatory 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 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.[1305]

Timing

CEG raised a number of concerns with the timing calculations applied in the draft decision. Specifically:[1306]

- Econtech's forecasts for EGW and general wages growth were in financial year average terms, and not in June to June terms
- Enterprise Bargaining Award (EBA) or Award rates 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.

L.5.3 Submissions

The EUAA stated that, due to the worsening economic climate, wage cost pressures had fallen. The EUAA noted the Reserve Bank of Australia (RBA) had revised its wage price index from 4 per cent in 2008–09 to 3.5 per cent in 2009–10. Further the RBA expects the wage price index to remain static at 4 per cent for 2010–11 to 2011–12.[1307]

The EMRF noted that due to current economic climate conditions, wage cost escalation data is out of date and labour cost escalation is not reflective of current expectations. It also noted that EGW and general wages should be discounted by long–term levels of inflation.[1308]

Origin Energy noted concerns with the predicted increases in labour costs based on earlier periods which suggests the data relied upon regarding labour cost growth is ceasing to

[1304] CEG, *Escalators affecting expenditure forecasts*, p. 13.
[1305] CEG, *Escalators affecting expenditure forecasts*, p. 14.
[1306] CEG, *Escalators affecting expenditure forecasts*, pp. 7–12.
[1307] EUAA, p. 18.
[1308] EMRF, pp. 14–15.

reflect actual changes. Further, Origin Energy noted economic data pointed to stable labour costs in 2009–10 compared with the 2006–07 and 2007–08 financial years.[1309]

L.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.[1310] Econtech's EGW labour cost growth rates are shown in table L.9

Table L.9: Econtech's real labour escalation rates for the EGW sector in NSW and Australia (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
NSW	1.3	–0.7	3.3	3.6	2.4	1.7	0.6
Australia	–0.7	–1.0	2.8	3.1	2.1	1.5	0.5

Source: Econtech, *Updated labour cost growth forecasts for the AER*, pp. 28, 31.

Econtech determined these forecasts using an updated version of its labour cost model (LCM).[1311] In particular, the forecasts provided by Econtech reflect the following factors:[1312]

- an enhanced approach to labour cost forecasting, which was initially used in the September 2008 report
- 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, which arose as a result of the ABS quantifying the extent of mis–reporting with data providers.[1313]

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

[1309] Origin Energy, p. 5.
[1310] Econtech, *Updated labour cost growth forecasts for the AER*.
[1311] This model was purpose-built by Econtech for its report to the AER in August 2007.
[1312] Econtech, *Updated labour cost growth forecasts*, p. 4.
[1313] ABS, *Cat. No. 6302.0.553.001*, *Information paper: revisions to average weekly earnings series*, August 2008.

markets remaining frozen and expected increases in unemployment rates as contributing factors to the Australia's forecast declining economic performance. [1314]

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 2010–11 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.[1315]

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.[1316] 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.[1317] 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.[1318]

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 that given the essential nature of utility services, they have a greater imperative to attract and maintain skilled workers.[1319]

Econtech made the following observations on the utility sector in NSW:[1320]

- the current economic slowdown particularly affects NSW, given its financial dominance in Australia
- state economic performance is expected to mirror the performance of Australia as a whole
- the slowing wages growth across all sectors/industries occurs in 2008–09 to 2010–11, given general economic conditions have shown the sharpest deterioration in this period
- EGW wages, despite having eased in the immediate forecast period, still remain above the national EGW average, which aligns with historical trends

[1314] Econtech, *Updated labour cost growth forecasts*, pp. 7–8.
[1315] Econtech, *Updated labour cost growth forecasts*, pp. 8–9.
[1316] Econtech, *Updated labour cost growth forecasts*, p. 9.
[1317] Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, 19 September 2008, p. 25.
[1318] Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, p. 23.
[1319] Econtech, *Labour cost growth forecasts 2007/08 to 2016/17*, p. 23 and Econtech, *Updated labour cost growth forecasts*, p. 9.
[1320] Econtech, *Updated labour cost growth forecasts*, pp. 11–12.

- the forecast EGW average annual real growth rate (at 2.7 per cent) is expected to be higher than the all–industry average (at 1.0 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 NSW.[1321] Econtech's updated general labour cost growth rates are shown in table L.10.

Table L.10: Econtech's real general labour escalation rates for NSW (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
NSW	0.9	–1.6	0.7	1.3	0.4	0.1	–0.6

Source: Econtech, *Updated labour cost growth forecasts*, p. 28.

As part of updating its forecasts, Econtech further undertook a review of CEG's report submitted in January 2009, which formed part of the NSW DNSPs' revised regulatory proposals.[1322]

L.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 that it 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.[1323] The AER maintains that the Macromonitor reports do not contain sufficient description of the methodology used to forecast wage growth.

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.[1324] 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.[1325]

The AER is satisfied that Econtech's methodology for forecasting labour costs growth is robust given the application of both an economy–wide model (Murphy model II (MM2)) and a purpose-built LCM.[1326] Econtech provided, in its report, additional information

[1321] Econtech, *Updated labour cost growth forecasts*.
[1322] Econtech, *Updated labour cost growth forecasts*.
[1323] Macromonitor, *Forecasts of Cost Indicators for the Electricity Transmission Sector - New South Wales and Tasmania*, p. 3.
[1324] Econtech, *Labour Cost Growth Forecasts 2007/08 to 2016/17*, p. 39.
[1325] Econtech, *Updated labour cost growth forecasts*.
[1326] Econtech, *Labour Cost Growth Forecasts 2007/08 to 2016/17*.

pertaining to its LCM and MM2 methodology and also advised further information and assumptions are publicly available.[1327]

The AER sought a list of exogenous variables, and assumptions, employed by Econtech to produce its labour forecasts.[1328] 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.[1329] 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.[1330] 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.[1331] 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 productivity assumptions for each 1–digit ANZSIC industry.[1332] The AER is therefore satisfied with the approach and methodology applied by Econtech to incorporate productivity in its wage growth forecasts.[1333]

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.[1334]

1327 Econtech, *Updated labour cost growth forecasts,* p. 21.
1328 Econtech, *Updated labour cost growth forecasts*, p. 25.
1329 The AER and CEG have previously applied Econtech's national forecasts in the SP AusNet and VENCorp revenue resets. See AER, *Draft decision*, p. 533.
1330 Econtech, *Updated labour cost growth forecasts*, pp. 20–26.
1331 CEG, *Escalators affecting expenditure forecasts*, p. 33.
1332 ANZSIC refers to the Australian New Zealand Standard Industrial Classification. See Econtech, *Updated labour forecasts for the AER*, p. 24.
1333 Econtech, *Labour Cost Growth Forecasts 2007/08 to 2016/17*, pp. 41–42.
1334 CEG, *Escalators affecting expenditure forecasts*, p. 13.

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 NSW DNSPs.[1335] 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 NSW specific general labour escalators should be applied to the NSW DNSPs general wages, as it reflects the economic circumstances and performance of NSW and is likely to be a better predictor of future trends in wages growth in NSW. Therefore, for this final decision the AER will apply Econtech's all industries wage growth forecast for NSW as the NSW DNSPs' general labour escalator.

For this final decision, the AER has adopted actual wage data increases for 2007–08 provided for under the NSW DNSPs' respective EBA or Award, which have been adjusted to incorporate for superannuation allowances, as part of the EGW labour escalation. In reviewing Integral Energy's EBA[1336] however, the AER has since identified an issue with adopting the EBA rate outlined in its draft decision. This rate included the average growth rate of all Integral Energy's allowances along with the base EBA and superannuation rate for 2007–08. In this final decision, the AER has adopted the NSW DNSP's EBA rate for 2007–08 which is adjusted, as described in this appendix. For 2008–09 and the next regulatory control period the AER has adopted Econtech's updated NSW EGW labour cost escalators for the NSW DNSPs.

CEG has stated that the AER has indicated it would use future EBA labour costs where these are available.[1337] To clarify, the AER is using the EBA or Award rates (where available) in the current regulatory control period to escalate labour costs from the base period[1338] to the end of the current regulatory control period. However, for the next regulatory control period the AER will adopt Econtech's updated NSW EGW labour cost growth forecasts. The AER does not consider it appropriate to use the NSW DSNPs EBA or Award rates for the next regulatory control period as this would move the NSW DNSPs from an incentive based framework to a cost of service recovery framework. This means that the NSW DNSPs still have an incentive to negotiate with its employees to obtain productivity savings under its EBA or Award.

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:

- inflation was correctly accounted for by only using real wage rates for both EBA or Award rates and EGW rates
- the EBA or Award 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.

[1335] AER, *Draft decision*, p. 181.
[1336] Integral Energy's EBA is for 26 December 2006 to 24 December 2008.
[1337] CEG, *Escalators affecting expenditure forecasts*, p. 8.
[1338] The base period for Country Energy is 2006–07, EnergyAustralia is December 2006 and Integral Energy is December 2007.

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.[1339] The AER has adopted Econtech's methodology for creating a quarterly EGW wage rate as it does not distort the annual wage rate.

The use of Econtech's quarterly conversion also allows the AER to account for timing issues in wage growth rates more accurately. CEG has criticised the application of the base period timing issue to labour. In the AER's opinion this issue is relevant for EnergyAustralia and Integral Energy as its forecasts have a specific base month of December 2006 and December 2007, respectively. The AER has implemented the same approach as CEG applied to materials cost escalators to account for the base period in labour costs. This is possible because Econtech's methodology for converting to a quarterly index converts the annual figure into an equivalent quarterly figure. The AER considers the base period timing issue should be taken into account and that consistency should be maintained between the labour and materials cost escalators.

The AER considered CEG's application of compounding formulae when converting the yearly EBA or Award 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 or Award rate increase in the first quarter of the financial year that corresponds to the NSW DNSPs' EBA or Award wage rate increase date. This approach maintains CEG's application of the EBA or Award 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 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 the NSW DNSPs, 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.[1340] The AER further notes the NSW DNSPs' concerns with Econtech updating its forecasts after their revised regulatory proposals have been submitted. To ensure a robust and transparent process on updating of labour wage growth forecasts, the AER engaged in a briefing with the NSW DNSPs, 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 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. The AER engaged Econtech to provide updated labour cost escalators based

[1339] Econtech, *Updated labour cost growth forecasts*, pp. 23–24.
[1340] CEG, *Escalators affecting expenditure forecasts*, pp. 7–12.

on most recent available data.[1341] The AER considers the updated forecasts take account of the current economic slowdown.

Electrical safety rules allowance

The AER has reviewed the NSW DNSPs' respective EBA or Award and confirms than an electrical safety rules allowance (ESRA) is required to be paid to certain employees. The AER is satisfied that this ESRA should be incorporated into the NSW DNSPs' EBA or Award rates. Therefore, based on the information provided by Country Engery and Integral Energy, the AER has calculated the ESRA rate for these businesses. The rates calculated were the same for both businesses due to the allowance rates for each business being the same.

As described in the respective EBA or Award, the ESRA is the same for all the NSW DNSPs. The AER requested information from the NSW DNSPs to confirm their respective ESRA rates. The AER considers EnergyAustralia provided insufficient information to accurately calculate its ESRA rate. However, due to timing constraints EnergyAustralia was unable to provide the AER with further information. Therefore, the AER considers it reasonable to apply the same ESRA rate for the NSW DNSPs based on the information provided by Integral Energy and Country Energy to EnergyAustralia. The AER has incorporated the ESRA into each of the NSW DNSPs' EBA or Award rates.

Conclusions

For this final decision, the AER has adopted Econtech's updated NSW EGW wage growth forecasts for the next regulatory control period. The AER has remodelled the forecasts to address CEG's timing issues and applied updated forecasts for the EGW sector in NSW for the 2008–09 regulatory year. Actual wage data was available for 2007–08 and therefore, the AER has applied actual wage increases provided for under the NSW DNSPs' EBA or Award for that year, which have also been remodelled to address CEG's timing issues.

The AER's conclusion on the EGW labour cost growth forecasts to apply to the NSW DNSPs for the next regulatory control period are shown in table L.11.

Table L.11: AER conclusion on NSW real EGW labour growth rates (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Country Energy	–0.17	–0.38	2.54	3.60	2.40	1.70	0.60
EnergyAustralia	1.46	0.20	3.35	3.60	2.40	1.70	0.60
Integral Energy	–	1.38	3.35	3.60	2.40	1.70	0.60

Note: Figures vary for the period 2007–08 to 2009–10 for the NSW DNSPs due to the different base periods used by each business.

For this final decision, the AER has also adopted Econtech's updated NSW general labour cost escalators for 2007–08 to 2013–14. The general labour cost growth forecasts

[1341] New forecasts incorporate data published by the ABS, including Average Weekly Earnings (released 26 February 2009) and National Accounts (released 9 March 2009).

the AER will apply to the NSW DNSPs' capex and opex for the next regulatory control period are set out in table L.12.

Table L.12: AER conclusion on NSW real general labour escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Country Energy	0.90	–1.60	0.70	1.30	0.40	0.10	–0.60
EnergyAustralia	1.01	–1.60	0.70	1.30	0.40	0.10	–0.60
Integral Energy	–	–1.80	0.70	1.30	0.40	0.10	–0.60

Note: Figures vary for the period 2007–08 to 2008–09 for the NSW DNSPs due to the different base periods used by each business.

As a result of the AER's analysis of the revised regulatory proposal, the AER is satisfied that the application of the updated EGW and general labour cost escalators for NSW (as set out in tables L.11 and L.12), to the NSW DNSP's capex and opex results in expenditure which 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.

L.6 Construction costs

L.6.1 AER draft decision

The AER, for the same reasons as set out for EGW wages and general labour forecasts (section L.5), also rejected CEG's approach to averaging construction forecasts from Econtech and Macromonitor.[1342] In the draft decision, the AER applied construction cost forecasts sourced from the Construction Forecasting Council (CFC) website[1343], which it deflated by CPI.[1344] The draft decision for construction cost forecasts are set out in table L.13.

Table L.13: AER draft conclusions for NSW DNSPs 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, *Draft decision*, p. 560.

[1342] This decision is not applicable to Country Energy as it did not identify any construction capex in its regulatory proposal.
[1343] Construction Forecasting Council, website http://www.cfc.acif.com.au/.
[1344] The CPI figures used to deflate the construction cost forecasts were sourced from: Econtech, *Australian National State and Industry Outlook*, 22 July 2006.

L.6.2 Revised regulatory proposals

EnergyAustralia and Integral Energy accepted the construction cost escalators applied by the AER in the draft decision, subject to the addressing of the issues raised by CEG and addressed in section L.5.2 of this appendix.

L.6.3 AER considerations

The AER will apply the same approach to construction costs, as it does to EGW wages and general labour forecasts (see section L.5.5 of this appendix). The AER also maintains the position it took in the draft decision to apply Econtech's construction cost forecast escalators. The AER does not consider it appropriate to rely on Macromonitor forecasts because there was no description of the methodology used to forecast growth in order 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 L.5).

AER conclusions

The AER notes EnergyAustralia and Integral Energy[1345] accept the application of its construction cost forecasts, subject to the AER reconciling the timing issues raised by CEG.[1346] The AER has adjusted its modelling to reflect timing issues raised by CEG.

The AER has applied updated CFC construction cost forecasts to EnergyAustralia's and Integral Energy's capex proposals, received by the CFC on 6 April 2009. The AER has deflated these construction costs with updated ANSIO inflation forecasts to provide real forecasts.[1347]

The AER's conclusions on forecast construction cost escalators are set out in tables L.14 and L.15.[1348]

Table L.14: AER conclusion on EnergyAustralia's real construction cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Construction Costs	3.17	–1.28	–1.64	1.00	0.65	–0.37	–2.22

[1345] This decision is not applicable to Country Energy as it did not identify any construction capex in its regulatory proposal.
[1346] CEG, *Escalators affecting expenditure forecasts*, pp. 7–12.
[1347] Econtech, *Australian National State and Industry Outlook*, 23 January 2009.
[1348] This decision is not applicable to Country Energy as it did not identify any construction capex in its regulatory proposal.

Table L.15: AER conclusion on Integral Energy's real construction cost escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Construction Costs	–	–0.91	–1.64	1.00	0.65	–0.37	–2.22

L.7 Producer margin

L.7.1 AER draft decision

The AER rejected the producer's margin escalators proposed by EnergyAustralia and Country Energy.[1349] The AER considered that a producer's margin escalator did not meet the underlying objective for inclusion in forecast costs under clause 6.5.7(c) of the transitional chapter 6 rules. Specifically, the AER considered that the information presented by the DNSPs was not sufficient to demonstrate that the associated expenditure reasonably reflected a realistic expectation of cost inputs over the next regulatory control period.[1350]

The AER also considered the addition of a producer's margin would represent a:[1351]

- 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 proportion of EnergyAustralia's and Country Energy's base costs assigned to this escalator to the 'other' escalation category, which was escalated by CPI.[1352]

L.7.2 Revised regulatory proposals

Country Energy and EnergyAustralia removed real cost escalation from the weightings attributed to producer's margins, as determined in the AER's draft decision. Integral Energy retained its original position to not include a producer's margin escalator.

The AER notes that, while EnergyAustralia has removed the weighting applied to the producer margin in recognition of softening international conditions, it has maintained that using a producer's margin is appropriate.[1353]

L.7.3 AER considerations

The AER accepts the NSW DNSP's revised regulatory proposals do not apply real cost escalation to the proposed producer's margin component of their forecast equipment purchase costs.

[1349] Integral Energy's original regulatory proposal did not include a producer's margin escalation component.
[1350] AER, *Draft decision*, pp. 557–558.
[1351] AER, *Draft decision*, p. 558.
[1352] AER, *Draft decision*, p. 559.
[1353] EnergyAustralia, *Revised regulatory proposal*, p. 30.

For the reasons discussed in the 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.

L.8 Indirect (producer's) labour

L.8.1 AER draft decision

The AER did not accept the producer's labour cost escalator applied by Country Energy and EnergyAustralia.[1354] Based on the information presented and its own analysis, the AER was not satisfied that expenditure associated with a real escalation of indirect labour costs was required to meet the capex and opex objectives.[1355]

The AER considered that the introduction of a labour component in equipment costs was inappropriate as it:[1356]

- 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 NSW DNSPs' base cost estimates of equipment.[1357]

L.8.2 Revised regulatory proposals

CountryEnergy

Country Energy rejected the draft decision on producer labour and maintained the producer labour cost escalator in its revised regulatory proposal. Country Energy's revised regulatory proposal did not provide further explanation or justification to support its indirect labour escalation.

EnergyAustralia

EnergyAustralia acknowledged that, while producer's labour costs would be passed on by its equipment suppliers, its ability to forecast movements in international labour costs is limited.[1358] It maintained the method used in its original proposal to forecast producer's labour cost components, however, it revised the values attributed to these components to reflect recent economic data. Specifically, EnergyAustralia made the following adjustments to its real indirect labour escalator:

[1354] Integral Energy's original proposal did not include a producer's labour cost escalator.
[1355] AER, *Draft decision*, p. 542.
[1356] AER, *Draft decision*, p. 541.
[1357] AER, *Draft decision*, pp. 541–542.
[1358] EnergyAustralia, *Revised regulatory proposal*, p. 30.

- set the producer's skilled labour component for internationally sourced equipment at zero per cent
- set the producer's unskilled labour component for internationally sourced equipment at zero per cent
- set the producer's unskilled labour component for domestically sourced equipment at zero per cent
- set the producer skilled labour component of domestically sourced equipment to the general labour rate.

EnergyAustralia applied the AER's draft decision to not include indirect labour costs associated with the processing of raw materials.[1359]

Integral Energy

Integral Energy maintained the approach applied in its original regulatory proposal and did not apply a producer's labour component in developing its equipment cost escalators.

L.8.3 AER considerations

The AER notes EnergyAustralia's revised approach to indirect labour cost escalators. The AER accepts the revised regulatory proposal to apply zero real cost escalation to unskilled producers' labour components of all equipment, and skilled labour components of internationally sourced equipment.

However, the AER does not accept the application of a general wage cost escalator to skilled labour components of domestically sourced equipment. Specifically, the AER remains unsatisfied that the revised approach is supported by appropriate data.

EnergyAustralia's methodology relies on ABS input–output data observed in 2001–02 to derive the proportion of labour as a contributor to the final cost of manufactured products.[1360] The AER considers the age of this data undermines its relevance for estimating indirect labour costs at the present time, and during the next regulatory control period. The ABS notes that even though its assumptions within the input–output tables may be realistic for the reference year (2001–02), they become progressively less so for later years.[1361] It also notes that the proportionality assumptions may be invalidated by economies of scale, technological change or substitution of factors.[1362]

ABS data reveals that, between 2001–02 and 2007–08, Australia experienced the following changes, which are relevant to the estimation of producer's labour costs:

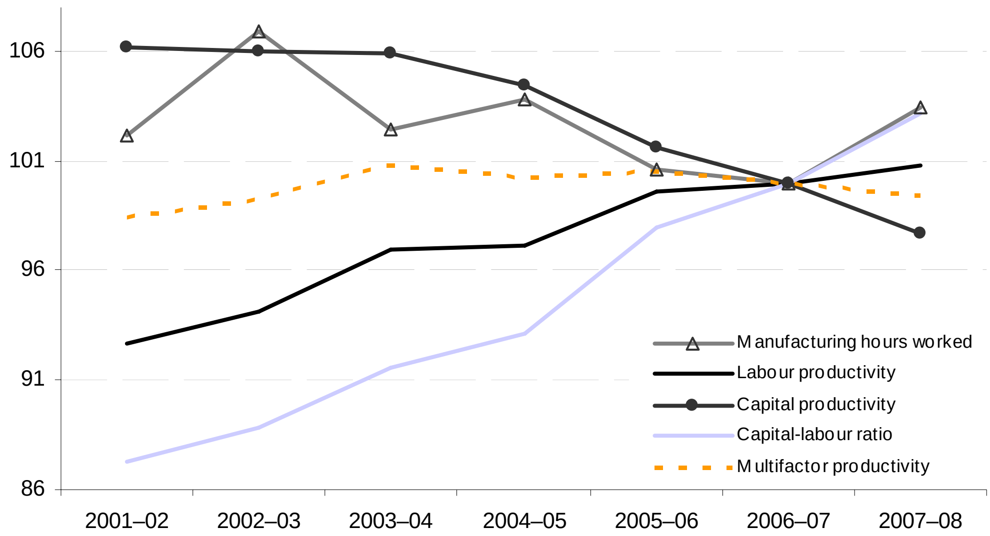
- labour productivity has increased by around 8.7 per cent[1363]
- capital productivity has decreased by around 8.0 per cent[1364]
- the capital-labour ratio has increased by over 18 per cent[1365]

1359 EnergyAustralia, *Revised regulatory proposal*, p. 31.
1360 ABS, *Cat no: 5209.0.55.001 - Australian National Accounts: Input-output tables 2001–02*, table 2.
1361 ABS, *Cat no: 5216.0 - Australian National Accounts: Concepts, Sources and Methods*, 2000.
1362 ABS, *Cat no: 5216.0 - Australian National Accounts: Concepts, Sources and Methods*, 2000.
1363 ABS, *Cat no: 5204.0 - Australian system of national accounts*, table 13
1364 ABS, *Cat no: 5204.0 - Australian system of national account*s, table 13.
1365 ABS, *Cat no: 5204.0 Australian system of national accounts*, table 13.

- manufacturing hours worked have decreased by around 2.2 per cent, while hours worked for all industries has increased by 14.6 per cent (2001–02 to 2006–07).[1366]

The extent of these changes in Australian factor productivity during recent times is illustrated in figure L.1.

Figure L.1: Productivity and manufacturing labour hours (index numbers)



Source: ABS, *Cat no: 5204.0 Australian system of national accounts*, tables 13 and 15.

The AER considers these variables are key determinants of the value of labour costs in final production and that the recent movements in these variables have not been considered by EnergyAustralia's in its revised regulatory proposal.

As a consequence of these productivity changes, the AER is not satisfied that the assumed weightings applied to indirect labour will accurately reflect the contribution of labour to manufacturing costs during the next regulatory control period.

Given these uncertainties, and the significance of input labour as a proportion of equipment costs proposed by the NSW DNSPs (up to 27 per cent), the AER considers the proposed approach creates significant estimation risk. The AER also notes CEG's statement that these forecasts are likely to be subject to a substantial margin for error.[1367] The AER therefore considers that no real cost escalation should be applied to the indirect labour components of domestically sourced equipment.

L.8.4 AER conclusions

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal, the AER is not satisfied that the inclusion of real cost escalation for producer's labour 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

[1366] ABS, *Cat no: 5204.0 Australian system of national accounts*, table 15.
[1367] CEG, *Escalators affecting expenditure forecasts*, p. 16.

achieve the capex objectives. In coming to this view, the AER has had regard to the capex factors.

Consistent with its draft decision, the AER has applied a zero weighting to the indirect producer's labour components of Country Energy's and EnergyAustralia's base equipment cost escalators. That is, any weighting attributed to producers labour has been reallocated to an alternative 'other' cost factor category, and will only attract CPI escalation.

L.9 Exchange rates

L.9.1 AER 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 L.16.

Table L.16: AER draft decision on AUD/USD exchange rate forecasts

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
AER draft decision	0.85	0.96	0.88	0.84	0.82	0.80	0.79

Source: AER, *Draft decision*, p. 556.

L.9.2 Revised regulatory proposals

In their revised regulatory proposal the NSW DNSPs applied 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.[1368] This represented the most recent forecasts available to CEG at the time it submitted the cost escalators to the NSW DNSPs.

L.9.3 AER considerations

Consistent with the draft decision, and the NSW DNSP'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 L.17.

Table L.17: AER conclusion on AUD/USD exchange rate forecasts

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
AER final decision	0.85	0.96	0.67	0.65	0.63	0.62	0.62

[1368] Econtech, *Australian National State and Industry Outlook*, October 2008.

L.10 Other issues

L.10.1 Wood poles

AER draft decision

The AER did not accept the wood pole escalators proposed by EnergyAustralia and Country Energy (approximately 5 and 1 per cent per annum respectively). The AER noted that by comparison ActewAGL and Integral Energy assumed real annual growth rates of zero per cent.[1369]

The AER also stated that:

- historic trends in prices do not provide an accurate forecast of future price movements and that EnergyAustralia had not provided any evidence to demonstrate its claims for real cost escalation of wood poles in line with historic price increases[1370]
- since Country Energy's proposed escalator for wood poles attributed weightings to indirect labour and producer's margin, which it did not consider appropriate, it considered that the proposed escalation of wood poles was also not appropriate.[1371]

The AER was therefore not satisfied that the proposed pole escalators from EnergyAustralia and Country Energy reasonably reflected the efficient costs required by a prudent operator to achieve the capex objectives. The AER concluded that the forecast expenditure for wood poles should not be subject to any real price escalation (that is, they were escalated by CPI only).[1372]

Revised regulatory proposals

Country Energy revised down the escalators applied to wood poles in its revised regulatory proposal. The revised wood pole escalators reflected Country Energy removing real cost escalation from the weightings attributed to producer's margins. Country Energy maintained that it was appropriate to apply real escalation for indirect labour (section L.8) to wood poles.

EnergyAustralia maintained that wood pole prices would increase by 5 per cent per annum in real terms over the next regulatory control period. EnergyAustralia argued that historic prices had not moved in line with CPI and that it had provided evidence that indicated that the supply shortages that contributed to real cost increases would continue.[1373]

AER considerations

The AER notes that Country Energy's only real escalation for wood poles is indirect labour and that, as discussed in section L.8, the AER is not satisfied that the inclusion of real cost escalation for indirect labour reasonably reflects the capex criteria.

[1369] AER, *Draft decision*, pp. 472–473.
[1370] AER, *Draft decision*, pp. 472–473.
[1371] AER, *Draft decision*, p. 436.
[1372] AER, *Draft decision*, pp. 472–473.
[1373] EnergyAustralia, *Revised regulatory proposal*, pp. 35–36.

The AER also notes that, according to the Queensland Department of Primary Industries and Fisheries:

> While the demand for poles is forecast to steadily increase over the next decade, the number of poles that are currently available from native forests is considered the maximum level of supply that is likely to be possible in the future.
>
> The majority of the more durable pole timber is supplied in equal proportions from private and public forests in both New South Wales and Queensland. The supply from New South Wales public forests is predicted to remain constant until 2039, with the relative proportion of native forest and plantation-grown poles expected to vary in the future. The supply from Queensland public native forests is planned to begin to be reduced in 2009, once the feasibility of alternative pole resources has been demonstrated.[1374]

The AER considers that while the supply of hardwood poles from native forests may decline there are alternative timber pole resources that can be considered by DNSPs to meet their requirements.[1375] Furthermore, the AER considers that the global financial crisis will impact the price of wood poles over the next regulatory control period.

The AER therefore does not consider that it is appropriate to assume that historic wood pole price will continue to increase at the same rate over the next regulatory control period.

The AER also notes that one of the capex factors in the NER is that it must have regard to when making its decisions is the benchmark capital expenditure that would be incurred by an efficient DNSP over the regulatory control period.[1376] The AER notes that both Integral Energy and ActewAGL (of which pole replacement represents 67 per cent of its replacement and renewal capex) have proposed that wood poles be escalated at CPI only. Furthermore, the AER considers that EnergyAustralia has not provided any evidence to suggest that the price changes it will face for wood poles will be significantly different from the other NSW DNSPs and ActewAGL.

The AER therefore concludes that the forecast expenditure for wood poles should not be subject to any real price escalation (that is, they should be escalated by CPI only).

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposal, the AER is not satisfied that the inclusion of real cost escalation for wood poles 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.

[1374] Queensland Department of Primary Industries and Fisheries, *Australian timber pole resources for energy networks: A review*, October 2006, p. 11.

[1375] QLD Department of Primary Industries and Fisheries, *Australian timber pole resources*, pp. 15–30.

[1376] NER, transitional chapter 6 rules, clause 6.5.7(e)(4).

L.10.2 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.[1377]

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 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.[1378]

L.10.3 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 L.4.4). 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.[1379] 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.

L.10.4 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.[1380] The AER considers that for data consistency, the West Texas Intermediate historical series should

1377 CEG, *Escalators affecting expenditure forecasts*, p. 17.

1378 CEG, *Escalators affecting expenditure forecasts*, p. 17.

1379 This methodology involves calculating the HRC steel prices using European and US steel price indexes.

1380 US Energy Information Administration, viewed 18 February 2009, http://www.eia.doe.gov/.

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.

L.11 Conclusion

The AER's conclusions on cost escalators for the NSW DNSPs are set out in tables L.18, L.19 and L.20.

Table L.18: AER conclusion on Country Energy's real escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–16.13	–17.34	–14.06	9.13	10.55	10.93	9.32
Copper	–6.93	–27.93	–10.83	2.06	2.46	2.32	1.96
Steel	5.57	16.27	–15.32	7.21	5.25	1.03	0.76
Crude oil	28.58	–18.33	–5.19	10.24	5.74	2.16	1.30
EGW wages	–0.17	–0.38	2.54	3.60	2.40	1.70	0.60
General wages	0.90	–1.60	0.70	1.30	0.40	0.10	–0.60
Construction costs	2.75	–1.28	–1.64	1.00	0.65	–0.37	–2.22

Table L.19: AER conclusion on EnergyAustralia's real escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–19.83	–17.34	–14.06	9.13	10.55	10.93	9.32
Copper	–1.31	–27.93	–10.83	2.06	2.46	2.32	1.96
Steel	12.40	16.27	–15.32	7.21	5.25	1.03	0.76
Crude oil	31.54	–18.33	–5.19	10.24	5.74	2.16	1.30
EGW wages	1.46	0.20	3.35	3.60	2.40	1.70	0.60
General wages	1.01	–1.60	0.70	1.30	0.40	0.10	–0.60
Construction costs	3.17	–1.28	–1.64	1.00	0.65	–0.37	–2.22

Table L.20: AER conclusion on Integral Energy's real escalators (per cent)

	2007–08	2008–09	2009–10	2010–11	2011–12	2012–13	2013–14
Aluminium	–	–10.19	–14.06	9.13	10.55	10.93	9.32
Copper	–	–17.35	–10.83	2.06	2.46	2.32	1.96
Steel	–	36.24	–15.32	7.21	5.25	1.03	0.76
Crude oil	–	–16.73	–5.19	10.24	5.74	2.16	1.30
EGW wages	–	1.38	3.35	3.60	2.40	1.70	0.60
General wages	–	–1.80	0.70	1.30	0.40	0.10	–0.60
Construction costs	–	–0.91	–1.64	1.00	0.65	–0.37	–2.22

Appendix M Self insurance

This appendix sets out the AER's assessment of the NSW DNSPs' proposed self insurance allowances in their opex forecasts for the next regulatory control period.

AER considerations

AER approach to assessing self insurance premiums

The AER considers that its approach to the assessment of the NSW DNSPs' self insurance allowances is consistent with the requirements of the transitional chapter 6 rules.

Clause 6.5.6(c) of the transitional chapter 6 rules states that the AER must accept the DNSP's forecast of opex if it is satisfied that the total of the forecast opex reasonably reflects the efficient costs that a prudent operator in the circumstances of the DNSP would require to achieve the opex objectives. Clause 6.5.6(d) requires that if the AER is not satisfied, it must not accept the forecast opex.

Further, clause 6.12.1(4)(ii) of the transitional chapter 6 rules states that where the AER does not accept the forecast opex, the AER must set out its reasons for that decision and an estimate of the total of the DNSP's required opex for the regulatory control period that the AER is satisfied reasonably reflects the opex criteria, taking into account the opex factors.

The opex factors which must be taken into account in deciding whether or not the AER is satisfied with the proposed costs or in determining a substitute amount are set out in clause 6.5.6(e) of the transitional chapter 6 rules.

In determining the prudence and efficiency of a DNSP's self insurance claims, the AER considered that the following opex factors, outlined in the transitional chapter 6 rules, were of most relevance:

- clause 6.5.6(e)(1)—the information included in or accompanying the building block proposal
- clause 6.5.6(e)(3)—analysis undertaken by or for the AER and published before the distribution determination is made in its final form
- clause 6.5.6(e)(4)—benchmark opex that would be incurred by an efficient DNSP over the regulatory control period
- clause 6.5.6(e)(5)—the actual and expected opex of the DNSP during any preceding regulatory control periods.

Each of these opex factors and their application is discussed below.

In assessing a DNSP's self insurance under clause 6.5.6(c) of the transitional chapter 6 rules the AER must have regard to the information included in or accompanying the building block proposal as outlined in clause 6.5.6(e)(1) of the transitional chapter 6 rules. Therefore, the transitional chapter 6 rules imply that the regulatory proposal should include sufficient information to justify a DNSP's self insurance cost forecasts, or in the event that the AER does not accept the forecasts, that there is sufficient information for which the AER may substitute an alternative forecast. This interpretation is supported by clause 6.12.3(f) of the transitional chapter 6 rules which states that:

> If the AER refuses to approve an amount, value or methodology referred to in clause 6.12.1, the substitute amount, value or methodology on which the distribution determination is based must be:
>
> (1) determined on the basis of the current regulatory proposal; and
>
> (2) amended from that basis only to the extent necessary to enable it to be approved in accordance with the Rules.

The AER considers that it is not the intent of the transitional chapter 6 rules that the AER generate forecasts on behalf of a DNSP where the DNSP has not provided adequate information in its regulatory proposal. Instead, the AER considers that the onus is on a DNSP to provide the necessary information to support its forecasts.

Some of the NSW DNSPs noted that the AER is not in a position to make informed decisions about the proposed self insurance allowances without the assistance of experts or questioned whether the AER based the draft decision on an actuarial assessment. Clause 6.5.6(e)(3) of the transitional chapter 6 rules states that the AER may have regard to analysis undertaken by or for the AER. The AER notes that it is not required by the transitional chapter 6 rules to engage an expert to review any opex forecast proposed by a DNSP. Further, it is not always necessary to seek the assistance of an expert to decide whether an opex forecast is reasonable. Depending on the level of information provided, the AER may be able to satisfy itself that the forecast expenditure is reasonable or unreasonable, without the help of an expert.

In considering clause 6.5.6(e)(4) of the transitional chapter 6 rules, the AER notes that benchmarking of self insurance costs could potentially provide an indication of the reasonableness of a self insurance claim. However, the AER notes that there:

- is no agreed definition of the individual events that should be included in a self insurance claim—the included events are at the discretion of the individual DNSP
- appears to be no agreed definition on what each of those defined events is to cover.

Since self insurance events and their associated costs are not readily comparable across businesses, it is unlikely that benchmarking will provide reasonable self insurance costs for an individual DNSP.

In considering clause 6.5.6(e)(5) of the transitional chapter 6 rules, the AER notes that self insurance was provided for the NSW DNSPs in the current regulatory control period.[1381] The AER considers that these previous self insurance allowances may provide a basis on which to consider the self insurance claims in the next regulatory control period. The AER notes that:

- the NSW DNSPs did not refer to the existing allowances in developing their forecasts for the next regulatory control period

[1381] IPART, *NSW Electricity Distribution Pricing 2004/05 to 2008/09 – Draft Report*, January 2004.

- based on the benchmarking discussion above, the self insurance events included and the definition of these events is at the discretion of the individual DNSP, there is no reason for these to be consistent between regulatory control periods
- the calculation of premiums may differ from one period to the next due to issues such as increased or reduced risk mitigation strategies.

Therefore, it is unlikely that historical self insurance claims could be used to determine robust forecasts in the next regulatory control period. At best, the AER considers that historical claims may provide an order of magnitude of aggregate self insurance costs for comparison with those proposed for the next regulatory control period.

Based on its assessment of the relevant opex factors, the AER considers it necessary to rely on the information provided in the regulatory proposals (consistent with clause 6.5.6(e)(1) of the transitional chapter 6 rules) in determining whether the proposed self insurance allowances reasonably reflect the opex criteria, including the opex objectives. Where the information concerning an individual self insurance cost forecast was inadequate—that is, it did not appear to support the forecast—the AER has not accepted the forecast (consistent with clause 6.5.6(d) of the transitional chapter 6 rules).

Similarly, in determining a substitute self insurance forecast, the AER relied on the information included in the regulatory proposal (as required by clauses 6.12.1(4)(ii) and 6.12.3(f) of the transitional chapter 6 rules). For a number of risks, based on the information provided to the AER in the regulatory proposals and revised regulatory proposals, the only value that the AER could assign to an event was zero because there was no information on which to base an alternative amount. Such a value is not meant to indicate that the self insurance event may or may not occur, rather, the AER has assigned a cost of zero due to the (lack of) information provided in the regulatory proposal.

Generally, the self insurance premiums proposed by the NSW DNSPs were accepted where the business was able to provide historical data related to the incidence and cost of an event in order to calculate the premiums. In the absence of such information, the AER accepts that a self insurance premium may be derived on the basis of information from other sources, including qualitative information. However, in such circumstances, as with any opex forecast, the onus is on the business to provide a compelling rationale for the use of that information or set of assumptions and to explain how such information has been used to derive the cost forecast (self insurance premium).

In a number of instances, SAHA justified its probability calculations (for example, in relation to bushfires) on the basis that the assumed probability is a more reasonable assumption, and produces an outcome that more reasonably reflects the efficient cost that a prudent operator is likely to incur over the next regulatory control period, when compared with the AER's approach of excluding the proposed cost associated with this risk in its entirety. The AER does not consider that such an assertion represents an appropriate justification for the probabilities and associated self insurance premiums presented by SAHA.

Further, it is not sufficient for DNSPs to simply state that a self insurance premium is reasonable without providing evidence in support of this claim. It is not adequate, for example, to suggest that since an event has occurred in another electricity business that it is also likely to occur in the business in question.[1382] Nor is it sufficient to apply a probability to the occurrence of such an event based on the occurrence in another business. The onus is on the business to provide the necessary information to support its forecasts to allow the AER to determine whether the forecast opex reasonably reflects the efficient costs that a prudent operator in the circumstances of the relevant DNSP would require to achieve the opex objectives. Such supporting information should reasonably include:

- the rationale used to determine the reasonableness of the forecast
- the process that the business underwent in determining the probability and cost estimates
- the factors that led the business to believe that the experience in another business can be applied to the business in question and how these factors have been translated into a premium
- why one value for the forecast risk is preferred over another.

SAHA indicated that its self insurance estimates were reviewed by an independent actuary. The AER notes that the actuarial review included a review of SAHA's methodology and risk premium calculations and a review of the reasonableness of assumptions used, based on the information provided in the SAHA reports and in discussions with SAHA. Importantly, the review did not include identification of the risks which are proposed to be self insured or the collection or primary analysis of the data on which the premiums were based.[1383] Based on this review, the actuary concluded that the figures in the SAHA report were '…reasonable for the purpose of submission as part of the price reset submissions,' but '…are not necessarily suitable for any other purpose, including decisions by the DNSPs regarding risk management and appropriate levels of insurance cover.'[1384]

The AER is concerned that the actuarial review draws a distinction between the development of self insurance estimates for a regulatory proposal and the use of these estimates by the NSW DNSPs as part of their risk management strategies. This suggests that the self insurance estimates calculated for use in the NSW DNSPs' regulatory proposals are somehow different to those that would be developed by the NSW DNSPs as part of their ongoing risk management. The AER expects the self insurance estimates developed as part of the DNSPs regulatory proposals to reflect the efficient level of self insurance for each of the DNSPs. As such, the AER considers the self insurance estimates calculated as part of the regulatory proposals to be the same as those that would be calculated by the DNSP in determining appropriate levels of overall insurance and to reflect the level of self insurance actually maintained by the DNSP. To the extent that this is not the case, it is not clear that SAHA's statement that its self insurance estimates have been approved by an independent actuary can be relied upon.

Given the limitations in scope and analysis the AER is unsure of the usefulness of the review. In particular, without a robust assessment of the entire self insurance premium

[1382] For example, the nature of the operations and assets, location of the network and risk mitigation programs to protect assets and income can influence the likelihood of an event occurring and the financial impact of that event.

[1383] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 65.

[1384] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 66.

calculations, including an examination of the underlying data used to calculate the premiums, it is not clear what the AER is suppose to derive from such a review. Based on the scope and analysis presented, the review simply represents an assessment of the process applied by SAHA to the data provided by SAHA—it provides no assurance to the AER that the resultant premiums are appropriate. Similarly, the review provides no information on whether the premiums were derived on the same or similar basis to that which would be used by the actuary (if these were derived by the actuary from the bottom up) or that the proposed premiums are the same or similar to those that the actuary would have produced.

While the AER accepts that an actuary reviewed SAHA's self insurance estimates, the review is not equivalent to an actuarial preparation of self insurance estimates. Based on its previous assessment of self insurance proposals, the AER notes that the preparation of self insurance estimates by an actuary typically involves the collection of historical and other relevant information, the application of quantitative techniques to obtain frequency and severity factors for identified risk categories, and the use of risk modelling to obtain simulated distribution parameters.[1385]

SAHA stated that where the AER has decided to reject a self insurance premium for a particular risk it should allow the NSW DNSPs to mitigate such risks in another way. The AER notes that it is not required under the transitional chapter 6 rules to propose alternative means of mitigating risks that the NSW DNSPs may face during the next regulatory control period. Rather, it is required to assess the forecast opex put forward by the NSW DNSPs and either accept or reject the forecast opex, and propose a substitute value based on the requirements set out in the transitional chapter 6 rules.

Notwithstanding the above, in assessing the revised self insurance premiums proposed by the NSW DNSPs, the AER has considered whether the risks for which a self insurance allowance is being proposed may be more appropriately treated as pass through events under the transitional chapter 6 rules.

Revised self insurance allowances

Bomb threat and terrorism

Country Energy and EnergyAustralia have proposed a self insurance premium for the cost impact of a bomb threat, hoax or terrorism event. The self insurance premiums for Country Energy and EnergyAustralia are:

- Country Energy—$13 000 per annum which consists of $2000 per annum for the impact of a bomb threat, hoax or extortion and $11 000 per annum for acts of terrorism
- EnergyAustralia—$74 000 per annum which consists of $2000 per annum for the impact of a bomb threat, hoax or extortion and $72 000 per annum for acts of terrorism.

[1385] See for example ElectraNet, *Transmission Network Revenue Proposal 1 July 2008 to 30 June 2013 - Appendix K*, May 2007 at http://www.aer.gov.au/content/item.phtml?itemId=712378&nodeId=3c71ef78e74a8f7eb396ac3f60a70d95&fn=Appendix%20K%20ElectraNet%20Self%20Insurance%20Risk%20Quantification%20Report%202006.pdf.

In the draft decision, the AER accepted Country Energy's and EnergyAustralia's self insurance premiums for the impact of a non–terror related bomb threat, hoax or extortion on the DNSPs. However, the AER did not accept the self insurance premium for the risk of a terrorist event on the basis that calculating a self insurance premium is difficult and that a terrorist event is listed as a defined pass through event under the transitional chapter 6 rules.

In its response, SAHA suggested that the materiality threshold associated with any cost pass through application means that the affected regulated business would not be compensated for bearing this risk when the net impact does not pass the materiality threshold.[1386] SAHA therefore considered that the risk of a terrorism event is best addressed through self insurance rather than as a cost pass through and requested that the original self insurance estimate for Country Energy and EnergyAustralia be reinstated by the AER.[1387] SAHA did not provide additional information in support of its original self insurance premium.[1388]

The AER considers that the choice between managing an event through self insurance or cost pass through should reflect the nature of the event. For example, such a decision should rely primarily on whether the frequency and cost associated with an event can be robustly determined and whether the event would result in catastrophic losses to the business. The materiality threshold applied to a cost pass through event is not a relevant consideration in this context.

Further, the AER reiterates that a terrorism event is included as a defined pass through event in the transitional chapter 6 rules. The AER maintains its draft decision and rejects the claim for self insurance of a terrorism event. If a terrorism event occurred the DNSPs would be able to submit a pass through application to cover the costs associated with the event. The AER would assess any such application, in accordance with the NER and any relevant guidelines, at the time the application was lodged.

Summary

The AER maintains its draft decision and accepts the premiums of $2000 per annum for Country Energy and $2000 per annum for EnergyAustralia for the bomb threat, hoax or extortion risk. The AER does not accept the self insurance premium for terrorism event on the basis that such an event is included as a defined pass through event in the transitional chapter 6 rules. The AER considers that the revised premiums reflect the efficient costs that a prudent operator in the circumstances of Country Energy and EnergyAustralia would require to achieve the opex objectives.

Earthquake risk

Country Energy and Integral Energy have proposed self insurance premiums for the cost impact of an earthquake of magnitude five and six impacting on their networks. The self insurance premiums are:

- Country Energy—$79 000 per annum which consists of $62 000 for the impact of an earthquake between magnitude five and six and $17 000 for the impact of an above magnitude six earthquake

[1386] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 26.
[1387] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 26.
[1388] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 26.

- Integral Energy—$255 000 per annum which consists of $198 000 for the impact of an earthquake between magnitude five and six and $57 000 for the impact of an above magnitude six earthquake.

In the draft decision, the AER accepted the self insurance premiums proposed by Country Energy and Integral Energy for the impact of an earthquake between magnitude five and six on the DNSPs. However, the AER did not accept the premiums in relation to above magnitude six earthquakes for these DNSPs on the basis that SAHA had not provided a reasonable basis for the adoption of a 1 in 166 year probability of an above magnitude six earthquake in NSW.[1389]

In response to the AER's draft decision, SAHA suggested that the AER has made the decision to exclude any self insurance risk allowance that is not supported by historical data.[1390] SAHA argued that 'such an approach is generally inconsistent with good risk management practices – namely that just because such an event has not occurred historically, does not mean that there is not a risk of it occurring sometime in the future.'[1391]

The AER agrees that an above magnitude six earthquake in NSW is possible, however, the AER is not required to determine if an event is possible or not, rather, the AER is required (under the transitional chapter 6 rules) to assess the associated opex (in this case, the self insurance premium). In doing so, the AER notes that SAHA's analysis acknowledges that there have been no magnitude six earthquakes recorded in NSW since records have been kept. However, SAHA indicates that, given that other such earthquakes have occurred in Australia over that period, it '…has assumed that there is a potential for at least one magnitude six earthquake to occur in NSW' and '…has assumed an expected value of 1 in the 166 year history'.[1392]

The AER notes that SAHA provided no further information in relation to this decision or for the derivation of the probability. The AER considers that the argument presented by SAHA does not constitute a satisfactory examination of the risks of such an earthquake in NSW. SAHA has not demonstrated that this probability is any more reasonable than, for example, 0 in 166 years or 1 in 300 years. The AER requires supporting information from SAHA to understand how SAHA derived this probability and to determine whether the probability actually represents a reasonable value or that some other probability is not preferred.

In the absence of such supporting information, the AER is unable to determine if the probability is reasonable. Accordingly, the AER is not satisfied that the proposed self insurance allowance reflects the efficient costs that prudent operators in the circumstances of Country Energy and Integral Australia would require to achieve the operating cost objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in the regulatory proposals and the revised regulatory proposals.

1389 AER, *Draft decision*, p. 626.
1390 SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 27.
1391 SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 27.
1392 SAHA, *Country Energy Self Insurance Risk Quantification*, confidential, p. 56.

Summary

The AER maintains its draft decision and does not accept the forecast self insurance allowance for Country Energy for an above magnitude six earthquake. The AER accepts the self insurance premiums of $62 000 per annum and $198 000 per annum for Country Energy and Integral Energy for earthquakes of between magnitude five and six.

Bushfire risk

The NSW DNSPs have proposed the following self insurance premiums for bushfire risks:

- Country Energy—$540 000 per annum
- EnergyAustralia—$504 000 per annum
- Integral Energy—$1.18 million per annum.

SAHA's original assessment of bushfire risk was separated into two types of bushfires—those ignited by the DNSP's own assets, and those ignited by a third party.

Bushfires ignited by a DNSP's own assets

This self insurance premium is based on the probability of the DNSP's own assets starting a major bushfire—that is, a bushfire causing more than $10 million damage.

SAHA calculated the probability of a major bushfire being caused by the DNSP's assets on the basis of information concerning minor bushfires over the past 11 years and the fact that one major bushfire had occurred in NSW over this period (in Integral Energy's network). SAHA calculated the cost of a major bushfire ignited by a DNSP's own assets on the basis of information from the Centre for International Economics (CIE)[1393] and the DNSP's asset data.

In the draft decision, the AER rejected the claim for self insurance, noting, in particular, that:

- SAHA provided no rationale for the application of an 11 year historical period
- the fact that one bushfire has occurred since the inception of Integral Energy (11 years ago) does not provide a basis for assuming that another major bushfire will occur in the next 11 years
- the functional relationship between damage costs and area burnt proposed by CIE cannot be relied upon
- the explanatory power of the proposed CIE functional relationship is poor. The coefficient of determination is reported as 0.39, implying that only 39 per cent of the variation in bushfire damage cost can be explained by the amount of hectares burnt.[1394]

[1393] CIE, *Assessing the contribution of CSIRO – CSIRO pricing review*, November 2000.
[1394] CIE, *Assessing the contribution of CSIRO – CSIRO pricing review*, p. 113.

SAHA responded by indicating that, based on the calculated probabilities, the future probability of Integral Energy starting a bushfire would be 1 in 30 years, not 1 in 11 years as suggested by the AER.[1395]

The AER notes that the response from SAHA does not address the previous point that the calculated probabilities for the NSW DNSPs are based on an assumption that a major bushfire will occur in NSW every 1 in 11 years (the value of the resultant calculated probability for a return bushfire on the Integral Energy network is not relevant in this respect). The key point is that the basis of these calculated probabilities has not been adequately explained. As previously indicated, SAHA has provided no information in support of the 1 in 11 year assumption.

As justification for its approach, SAHA's revised report attempted to demonstrate that the calculated return period for a major bushfire for Integral Energy, 1 in 30 years, is correct (and therefore that the underpinning 1 in 11 year probability of a major bushfire in NSW is correct). SAHA provided additional information from the Emergency Management Australia (EMA) Disaster Database showing that there were two major bushfires ignited by electricity assets in NSW over the past 68 years.[1396]

The AER notes, however, that in relation to one of these bushfires (in EnergyAustralia's network), there is no damage information to support SAHA's contention that this was a major bushfire—that is, greater than $10 million damage—the event resulted in damage to 950 hectares (substantially below the 80 000 hectares that SAHA suggests is associated with a major bushfire and the 44 000 hectares associated with a minor bushfire)[1397] and the event was not previously identified by EnergyAustralia as a major bushfire.[1398] Accordingly, it is not clear that this event was in fact a major bushfire as defined by SAHA. Therefore, based on the information provided by SAHA it appears that there has only been one major bushfire ignited by electricity assets in NSW in the past 68 years. This appears to contradict the application of a 1 in 11 year probability previously used to determine major bushfires started by electricity assets in NSW and the 1 in 30 year return period associated with a major bushfire in the Integral Energy network.

While the AER appreciates that the information regarding major bushfires may not have been reported in sufficient detail in the EMA Disaster Database to identify the cause of those bushfires, SAHA has provided no further information to support a more frequent occurrence than that observed in the information provided. The AER therefore rejects the probability of a major bushfire ignited by the NSW DNSP's own assets, as derived by SAHA, on the basis that the information provided by SAHA does not support its conclusions.

In the draft decision, the AER indicated that SAHA relied on information from the CIE to calculate the costs associated with a major bushfire ignited by the DNSP's own assets. The AER identified a number of issues associated with the use of this information by SAHA including that the functional relationship between damage costs and area burnt proposed by CIE could not be relied upon.

[1395] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 30.
[1396] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 31.
[1397] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 33.
[1398] Further, it is not clear that this bushfire was caused by distribution assets rather than transmission assets.

SAHA responded by indicating that it did not use the costs identified in the CIE report to determine damage area.[1399]

The AER notes that it did not indicate that SAHA used the costs in the CIE report, rather that it used the functional relationship in the CIE report to establish costs for NSW DNSPs.[1400] As indicated in the draft decision, and confirmed by SAHA in its response to the AER's draft decision,[1401] SAHA used the functional relationship from the CIE report to establish:

- the value of minor bushfires (and from this the ratio of major to minor bushfires); and
- the average hectares of land burnt during a minor and major bushfire.

SAHA then applied the average hectares of land burnt during a minor and major bushfire to the DNSPs' average value of assets per square kilometre to determine the value of damage caused by a minor or major bushfire for each of the DNSPs.[1402]

The AER considers that if the function relationship developed in the CIE report is not robust, then the value of damage caused by a minor or major bushfire calculated by SAHA (based on this functional relationship), cannot be relied upon. As indicated in the draft decision, the AER identified a number of issues with the functional relationship derived in the CIE report. In particular:

- based on an examination of the historical data underpinning the CIE modelling, the AER is unable to unambiguously match the values provided in the CIE report with those in the base data[1403]
- for those values that can be identified, it appears that the damage costs used by CIE to forecast the relationship have not been converted to constant dollars. As such, the observations are not comparable over time[1404]
- the explanatory power of the proposed CIE functional relationship is poor. The coefficient of determination is reported as 0.39, implying that only 39 per cent of the variation in bushfire damage cost can be explained by the amount of hectares burnt.[1405]

Notwithstanding these issues, the AER notes that SAHA appears to have incorrectly applied the information in the CIE report in deriving the damage area associated with a major bushfire ignited by a DNSP's own assets. SAHA used the CIE report (the functional relationship) to derive the average hectares of land burnt during a major bushfire, indicating that a major bushfire would cause damage to 80 000 hectares.[1406]

[1399] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 33.
[1400] AER, *Draft decision*, p. 628.
[1401] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 33.
[1402] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 33.
[1403] This assessment is based on an examination of the data source in its current format. Given the historical nature of the data, the AER would not expect any deviation between this data set and that used by CIE over the observed timeframe. See: http://www.ema.gov.au/ema/emadisasters.nsf/webEventsByCategory?OpenView&Start=1&Count=30&Expand=1#1.
[1404] The AER notes that the CIE acknowledges this point and suggests, therefore, that the derived relationship is conservative.
[1405] CIE, *Assessing the contribution of CSIRO – CSIRO pricing review*, p. 113.
[1406] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 33.

However, the AER notes that the CIE report advises against the use of this relationship, stating that '(f)or other cost items, such as injuries, fatalities and damage from major events, it is more appropriate to base damage costs on event frequencies rather than areas burnt.'[1407] Notwithstanding this point, the AER notes that if the CIE report were to be used for this purpose, the average area of land burnt by a major bushfire would be 800 000 hectares not 80 000 hectares as proposed by SAHA.[1408]

In support of its cost calculations, SAHA provided additional information related to hectares burnt by major bushfires in Australia over the past 80 years.[1409] SAHA suggested that the information indicated that the area burnt by a major bushfire '…is more than 6 times the figure used for the quantification'[1410]—that is, the 80 000 hectares derived from SAHA's analysis above. The AER notes that SAHA has not explained why this information differs so significantly from that derived by SAHA from the CIE report and relied upon to determine the costs associated with major bushfires. Further, SAHA has not indicated the source of this additional information and has not indicated how it defined the major bushfires listed—SAHA previously used costs to define a major bushfire, but no cost information is provided.

SAHA also provided information from the Council of Australian Governments report—National Inquiry on Bushfire Mitigation and Management—dated December 2004, which listed all the main bushfires that have occurred in each State and Territory in Australia. SAHA suggested that this data supported the damage areas calculated by SAHA (44 000 hectares and 80 000 hectares for minor and major bushfires respectively).[1411] As per the previous additional information provided by SAHA, the AER notes that SAHA has not clarified how a major bushfire is defined in the data. Nor has SAHA explained the distinction between a minor and major bushfire provided in this additional information. It is therefore not possible from the additional information to determine the damage area associated with a major bushfire.

Based on the above assessment, the AER considers that it is not appropriate to use the CIE report as proposed by SAHA and furthermore, that even if the data were appropriate, SAHA has incorrectly interpreted the information in the CIE report to determine costs associated with a major bushfire ignited by a DNSP's own assets.

On this basis, the AER does not consider that the proposed self insurance premiums for this risk of bushfires reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives.

The AER notes that the information provided by SAHA is contradictory, making it difficult to determine the appropriate information to use in determining the costs associated with a major bushfire. While it may have been possible for the AER to defer to cost information in relation to the Appin bushfire in the Integral Energy network to estimate these costs, the AER notes that this cost information also utilises the CIE report. Accordingly, based on the information provided in the regulatory proposals and the revised regulatory proposals, the AER is unable to calculate a value for the self insurance premium.

[1407] CIE, *Assessing the contribution of CSIRO – CSIRO pricing review*, p. 110.
[1408] See CIE, *Assessing the contribution of CSIRO – CSIRO pricing review*, p. 113.
[1409] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 34.
[1410] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 34.
[1411] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 34.

Bushfires ignited by a third party

The self insurance premium for bushfires ignited by a third party consists of a premium for minor bushfires and a premium for major bushfires.

In its original report, SAHA noted that there is no history of a (minor or major) bushfire ignited by a third party impacting on the NSW DNSPs. However, SAHA suggested that the sheer number of minor bushfires per annum ignited by a third party—around 300 per year—indicated that there was a considerable chance that one such minor bushfire could cause damage to the DNSPs' asset base.[1412] Accordingly, SAHA suggested that it was reasonable to assume a DNSP in NSW would be impacted by a minor bushfire incident caused by a third party once every 15 years.[1413]

In addition, SAHA used the information from the CIE report to determine the damage area associated with a minor (and major) bushfire and from that information and the DNSPs' asset data, the costs associated with a bushfire ignited by a third party.

In the draft decision, the AER noted that the NSW bushfire data referred to by SAHA reflects bushfire incidents in only one year (2002−03) and represented one of the worst bushfire seasons in NSW history. Notwithstanding this issue, the AER considered that SAHA had not established a robust relationship between the incidence of bushfires in NSW and the adoption of the associated probabilities. The AER also identified issues associated with the use of the CIE report as previously discussed. As a result, the AER rejected the self insurance premium in relation to minor bushfires ignited by a third party.

In response, SAHA defended the use of bushfire information from the NSW Rural Fire Services, indicating that it did not believe that the percentage of bushfires ignited by different sources (electrical power lines and third parties) was likely to change significantly, even when the data was from the worst bushfire season.[1414]

The AER notes the above point, however, consistent with the draft decision, the AER considers that SAHA has not established a robust relationship between the incidence of bushfires in NSW and the adoption of the 1 in 15 year probability that a NSW DNSP would be affected by such a fire. SAHA has provided no explanation concerning the relationship between bushfires in NSW and the potential for damage to the DNSP's assets. Further, there is no explanation of how the 1 in 15 year probability associated with damage to the DNSP's assets has been derived. The only discussion on this issue is provided in SAHA's original report where SAHA indicates that, despite no recorded incidents of asset damage caused by such fires, the number of third party fires suggests that '…it is reasonable to assume a DNSP in NSW would be impacted by a minor bushfire incident caused by a third party once every 15 years'.[1415] SAHA has provided no further information to demonstrate that such an assumption is reasonable. Based on the limited information provided, the AER is unable to satisfy itself that such an assumption is reasonable.

1412 SAHA obtained this information from a 2002−03 NSW Rural Fire Services report.

1413 SAHA reduced this probability to 1 in every 30 years for EnergyAustralia on the basis that EnergyAustralia operates in the metropolitan region which is less prone to bushfire hazard.

1414 SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 39.

1415 See for example SAHA, *Country Energy Self Insurance Risk Quantification*, confidential, p. 89.

In determining the costs associated with a minor bushfire ignited by a third party, SAHA used information from the CIE report. As discussed above, the AER identified a number of issues associated with the use of the information provided in the CIE report.

Further, the AER has identified issues associated with SAHA's application of the CIE report to determine the damage area associated with a minor bushfire. SAHA suggested that minor bushfires cause $58.5 million damage.[1416] This value can be derived from the average annual area burnt by small to medium bushfires in Australia[1417] and the functional relationship between damage costs and area burnt for major bushfires.[1418] Based on this approach, the resultant value of $58.5 million represents the total cost associated with all minor bushfires in Australia in a single average year.

SAHA used this value to determine a ratio of major to minor bushfires.[1419] SAHA then used this ratio to derive damage associated with a single minor bushfire—SAHA indicated that a single minor bushfire would damage 44 000 hectares.[1420]

The AER notes, however, that SAHA has incorrectly used 80 000 hectares as the amount of area burnt by a major bushfire (rather than 800 000 hectares)[1421] and that the ratio derived by SAHA actually represents all minor bushfires in a single year in Australia rather than a single bushfire and therefore cannot be used to calculate the damage associated with a single minor bushfire.[1422]

Since the release of the draft decision (and the provision of the SAHA response), EnergyAustralia provided advice to the AER indicating that a minor bushfire had occurred on the EnergyAustralia network in January 2009. EnergyAustralia suggested that the occurrence of such an incident indicated that the AER's decision to substitute a zero premium for self insurance for this risk was incorrect.[1423] EnergyAustralia indicated that the bushfire did not result in an outage and did not damage its network.[1424]

The AER does not deny that such an incident can occur. However, based on the probability and cost information provided in the regulatory proposal, the AER is unable to determine that the proposed premium is reasonable and is not able to calculate an alternative premium. The additional information provided by EnergyAustralia in relation to a minor bushfire in January 2009 provides no additional support to the proposed self insurance premium. In particular, the self insurance premium relates to the risk that a bushfire ignited by a third party will impact on EnergyAustralia's assets. However, the

[1416] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 33.
[1417] CIE, *Assessing the contribution of CSIRO – CSIRO pricing review*, table 7.5, p. 112, Note the CIE indicates that these refer to small to medium bushfires i.e. minor bushfires. See CIE, *Assessing the contribution of CSIRO – CSIRO pricing review*, p. 108.
[1418] CIE, *Assessing the contribution of CSIRO – CSIRO pricing review*, chart 7.7, p. 113. The cost function in the CIE report predicts a damage cost of $133 000 for every 1000 hectares burnt by wildfire. According to the CIE report, the average annual area burnt by bushfires in Australia = 440 000 hectares. Hence the damage cost = 440 x $133 000 = $58.5 million.
[1419] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 33.
[1420] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 33.
[1421] See the section on major bushfires ignited by a NSW DNSPs' own assets for a discussion of this value and its appropriateness to the analysis.
[1422] The AER notes that, using the ratio in its corrected format results in a final value for area burnt by all minor bushfire in Australia of 440 000 hectares (consistent with the value provided in table 7.5 of the CIE report).
[1423] EnergyAustralia, *Further submission*, p. 10.
[1424] EnergyAustralia, email to the AER, 24 February 2009.

AER notes that EnergyAustralia indicated that the recent incident did not damage EnergyAustralia's assets. Notwithstanding this point, EnergyAustralia has provided no information to explain how the incident can be used to support the proposed self insurance premium.

Based on the above, the AER is not satisfied that the premium associated with minor bushfires caused by third parties reflects the efficient costs of a prudent operator in the circumstances of the NSW DNSPs and rejects the self insurance premiums.

Based on the information provided in the CIE report, the AER calculates that a minor bushfire in NSW burns an average area of approximately 240 hectares.[1425] However, the AER is unable to develop an alternative probability for such bushfires or to determine an appropriate average cost based on the lack of supporting information provided in the regulatory proposals and revised regulatory proposals.

In the case of a major bushfire ignited by a third party, SAHA used the CIE report to derive the probability of a major bushfire in NSW. SAHA combined this information with the previously derived probability of a third party causing a bushfire incident in NSW—that is, 1 in 15 years—to calculate the probability of a major bushfire being ignited by a third party in NSW. SAHA used the information from the CIE report and the DNSP's asset data to determine the cost associated with a major bushfire ignited by a third party.

In the draft decision, the AER did not accept the self insurance premium associated with a major bushfire ignited by a third party on the basis that:

- the proportion of major bushfires accounted for in NSW (from the CIE report) appears to relate to minor rather than major bushfires as proposed by SAHA[1426]
- SAHA provided no explanation for the assumed probabilities of a minor bushfire incident caused by a third party impacting the NSW DNSPs
- SAHA's forecast costs were derived on the same basis as those for a major bushfire ignited by the NSW DNSPs' assets—that is, based on the CIE proposed relationship between damage costs and damage area. The AER noted that it had identified a number of issues associated with the functional relationship used by the CIE.

In its response, SAHA defended the use of data from the NSW Rural Fire Services for the 2002–03 year and provided further explanation on the use of the CIE report in developing the cost forecasts (as discussed above).

The AER maintains that the proportion of major bushfires accounted for in NSW (from the CIE report) appears to relate to minor bushfires. It is not clear to the AER that this same proportion can be applied to the incidence of major bushfires. Notwithstanding this issue, the AER maintains that SAHA has not established a robust relationship between the incidence of bushfires in NSW and the adoption of the 1 in 15 year probability that a NSW DNSP would be affected by such a fire. Further, as discussed above, the AER has identified issues associated with the use of the CIE in developing cost estimates associated with a major bushfire.

[1425] This calculation is based on the long run average number of annual bushfires in NSW and the average annual area burn by these bushfires, provided in table 7.5 of the CIE report.

[1426] CIE, *Assessing the contribution of CSIRO – CSIRO pricing review*, p. 108 and table 7.5.

On the basis of this analysis, the AER concludes that it is not satisfied that the self insurance premiums associated with minor and major bushfires caused by third parties reflect the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in the regulatory proposals and the revised regulatory proposals.

Summary

The AER maintains its draft decision and does not accept the self insurance allowances for the NSW DNSPs for a major bushfires caused by a DNSP's own assets or a third party or for a minor bushfire ignited by a third party. Accordingly, the AER does not accept the proposed self insurance premiums of $540 000 per annum for Country Energy, $504 000 per annum for EnergyAustralia and $1.18 million per annum for Integral Energy.

Non–terrorist impact of planes and helicopters

The NSW DNSPs have proposed the following self insurance premiums for the risk of a non–terrorist aviation strike impacting on their assets:

- Country Energy—$57 000 per annum
- EnergyAustralia—$11 000 per annum
- Integral Energy—$138 000 per annum.

In the draft decision, the AER accepted the self insurance premiums proposed by SAHA for Integral Energy and Country Energy for the risk of a non–terrorist impact by planes and helicopters. However, the AER did not accept the self insurance premium for EnergyAustralia on the basis that SAHA had not provided a sufficiently robust estimate for the probability of an aviation strike on its network.

SAHA suggested that the AER's main driver for coming to this conclusion appears to be due to the fact that EnergyAustralia has not experienced an incident since it has been keeping records.[1427] SAHA suggested that in undertaking its self insurance quantification, it acknowledged this fact, along with the mainly urban nature of EnergyAustralia's business, and therefore adopted a low, but non–zero probability of such a risk occurring, relative to adopting just the industry average.[1428]

SAHA suggested that the event represented a real risk to EnergyAustralia, and therefore, compensation should be provided for bearing this risk based on an unbiased estimate of the cost of bearing that risk.[1429] SAHA believed that this approach was consistent with what a 'reasonable' practitioner would adopt, namely to leverage off applicable data from other jurisdictions/business, in combination with public data and qualitative evidence to support such an unbiased estimate of the cost associated with this risk.[1430]

[1427] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 40.
[1428] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 40.
[1429] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 40.
[1430] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 40.

SAHA has provided no further evidence or support for the probability of an airstrike of 1 in 5 years applied to the EnergyAustralia network.

The AER does not deny that there is a risk of such an incident occurring to EnergyAustralia's network, however, as previously discussed, the AER is not required to determine if a risk exists or not. Rather, the AER is required under the transitional chapter 6 rules to assess the proposed operating costs (the self insurance premiums).

Contrary to SAHA's assumption, the AER has not rejected the self insurance premium on the basis that there is no historical information. Rather, the AER considers that the self insurance premium provided by SAHA (specifically the probability) has not been substantiated. While the 1 in 5 year probability provided by SAHA may very well be reasonable, SAHA has provided no evidence to support this claim. For example, SAHA has not identified the risk factors in relation to air strikes for the EnergyAustralia vis-à-vis the other NSW DNSP networks and has not utilised these factors to explain how the probability for EnergyAustralia has been derived.

Since the release of the draft decision (and the provision of the SAHA response), EnergyAustralia provided information to the AER indicating that an aviation strike had occurred on the EnergyAustralia network in January 2009. EnergyAustralia indicated that this demonstrated that the AER's conclusion that a zero probability for events that have not previously occurred was incorrect.[1431]

As indicated above, the AER did not apply a zero probability to such an event, rather, based on the information provided, the AER was unable to determine that the proposed probability was reasonable and was not able to calculate an alternative probability.

In relation to the recent aviation strike, EnergyAustralia indicated that there were no liability claims arising form the incident and the costs to restore the network were $6123.[1432] Based on this information the AER has derived a probability associate with such an event of 1 in 12 years or 0.08 incident per year.[1433] Based on the cost information provided,[1434] this equates to a self insurance premium of $510 per annum.

Based on the above assessment, the AER is not satisfied that the proposed self insurance premium for an aviation strike on EnergyAustralia's network reflects the efficient costs of a prudent operator in the circumstances of EnergyAustralia.

Summary

The AER rejects EnergyAustralia's proposed self insurance premium for non–terrorist aviation strike impacting on its assets. Given the insignificance of the amount that was re–calculated by the AER, the AER has not included the self insurance allowance for EnergyAustralia. The AER previously accepted the self insurance premiums of $138 000 per annum and $57 000 per annum for Integral Energy and Country Energy respectively.

1431 EnergyAustralia, *Further submission*, p. 10.

1432 EnergyAustralia, email, 24 February 2009.

1433 The 12 year time frame reflects the period over which EnergyAustralia has maintained records of such incidents.

1434 The AER notes that EnergyAustralia provided no other evidence to indicate that future costs would potentially be higher than those reported for the most recent incident.

Poles and lines

Country Energy and EnergyAustralia sought self insurance in relation to damage to their poles and lines as a result of a catastrophic storm. The proposed self insurance premiums are:

- Country Energy—$279 000 per annum
- EnergyAustralia—$763 000 per annum.

In the draft decision, the AER did not accept the self insurance premiums derived by SAHA for Country Energy and EnergyAustralia.

In the case of Country Energy, the AER indicated that it considered that the media statement relied upon by SAHA to determine the future probability of a catastrophic storm did not constitute a robust assessment of the probability of a catastrophic storm impacting Country Energy's network.

In relation to EnergyAustralia, the AER rejected SAHA's self insurance claim on the basis that the 1 in 11 year probability of a catastrophic storm for EnergyAustralia had not been robustly determined. In particular:

- there was no rationale for the application of an 11 year historical period
- the fact that one catastrophic storm occurred since the inception of EnergyAustralia (11 years ago) does not provide a basis for assuming that another catastrophic storm will occur in 11 years.

In response, SAHA argued that there is a real risk of such an event occurring and maintained that a 1 in 11 year probability (EnergyAustralia) and 1 in 30 year probability (Country Energy) for a catastrophic storm reasonably reflects the efficient costs that a prudent operator would incur.[1435] In support of this argument, SAHA provided additional information.

SAHA presented storm information from the EMA Disaster Database for NSW for the last 20 years. SAHA acknowledged that it is difficult to assess the specific damage caused by these storms to powerlines as this is not quantified in the database, but suggested that in all likelihood, many of them would be classified as a catastrophic storm. In particular, SAHA suggested that it is clear that three storms listed in the EMA Disaster Database for NSW would clearly meet this criterion.[1436]

The AER notes that SAHA previously defined a catastrophic storm as follows:[1437]

> …the NSW DNSPs consider it reasonable to define a 'catastrophic storm' as similar in magnitude to the recent 2007 Lower Hunter Valley occurrence that impacted EnergyAustralia's assets. According to EnergyAustralia, this low probability but high consequence event impacted their SAIDI by more than 198 minutes and the total cost (capital and operations) tied to this catastrophic storm was estimated to be $16,200,000, 16 times more than what is typically expected from a severe storm.

[1435] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 46.
[1436] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 43.
[1437] SAHA, *Response to AER enquiry on Self Insurance*, 17 September 2008, p.11.

The AER notes that SAHA has provided no cost or system average interruption duration index (SAIDI) information to confirm that the storms in the EMA Disaster Database, and assumed by SAHA to represent catastrophic storms in NSW, were in fact catastrophic as defined by SAHA. In particular, the AER notes that one of the storms identified by SAHA (Hunter Valley and Tablelands in 1998) occurred in the EnergyAustralia network. However, the AER notes that EnergyAustralia has not identified this event as a catastrophic storm in its regulatory proposal.

SAHA suggested that relying on the information contained in the EMA Disaster Database to derive the self insurance premium is a conservative approach. SAHA noted that the EMA Disaster Database is limited in detail beyond the last 10 years and therefore there is a major risk in using the full dataset to derive the overall probability of a catastrophic storm impacting electricity assets as incidents mentioned at a high level in the EMA Disaster Database may not have discussed in enough detail the impact that they had on electricity assets.[1438] SAHA also indicated that it is unclear whether the database has captured all relevant storms that affected NSW.[1439] In addition, SAHA noted that even over the past 20 years, '…it is difficult to gauge the exact magnitude of the damage based on the qualitative evidence provided in the database.'[1440]

The AER considers that there is doubt as to how many of the storms identified in the EMA Disaster Database (and used by SAHA) are in fact catastrophic storms according to the definition provided by SAHA.[1441] As a result, the AER concludes that the additional information provided by SAHA provides no further support for the 1 in 30 year probability applied to Country Energy or the 1 in 11 year probability applied to EnergyAustralia.

SAHA noted that a key aspect of the recent catastrophic Hunter Valley storms appears to have been the wind speed generated. SAHA used information from GeoScience Australia examining wind speeds in the Sydney region and return periods related to these wind speeds to support the 1 in 11 year probability applied to a catastrophic storm in the EnergyAustralia network.[1442]

SAHA suggested that the data show a return period in the Williamtown region (in close proximity to Newcastle) of 1 in 10 years for wind gusts of 119 km/hr. SAHA noted that this is similar to the wind gusts recorded in Newcastle (part of the area affected by the Hunter Valley storms) and therefore provided support for the 1 in 11 year return period calculated for EnergyAustralia.[1443]

[1438] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 43.
[1439] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 44.
[1440] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 44.
[1441] The distinction between a severe and catastrophic storm is vital to the AER's assessment. An allowance for severe storms is already included in the businesses operating expenditure baseline. Thus, it is important to ensure that the self insurance allowance only incorporates catastrophic storms otherwise the business will receive an allowance for risks that are already compensated for in the baseline expenditure.
[1442] GeoScience Australia, *A Statistical Model of Severe Winds*, 2007. http://www.ga.gov.au/image_cache/GA10911.pdf.
[1443] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, pp. 43–44.

Based on additional information provided by SAHA, the AER has determined that the Hunter Valley storms involved maximum wind gusts averaging around 130 km/hr.[1444] Further, based on the information provided in the GeoScience Australia report[1445], the AER considers that a return period for a storm involving maximum wind gusts of around 130 km/hr is more likely to be 55 years. The data shows that a 10 year return period can be expected for maximum wind gusts of 119 km/hr in Williamtown, with a 100 year return period expected for wind gusts of 140 km/hr. The same return period is estimated for similar maximum wind gusts averaged over the entire Sydney region. All things being equal, this suggests that maximum wind gusts averaging around 130 km/hr could be expected to occur every 55 years in Williamtown and the Sydney region in general (i.e. half way between a 10 year and a 100 year return period).

SAHA also indicated that the materially lower wind speed average recorded in Richmond suggested that inland NSW may be less prone to large wind gusts and that this confirms that the probability of a catastrophic storm for Country Energy should be lower than EnergyAustralia's.[1446]

The AER considers that this may well be the case, but this observation does not explain the derivation of the 1 in 30 year probability for Country Energy or the relativity of the probabilities between Country Energy and EnergyAustralia.

While the regulatory proposal provided a proxy for the costs associated with a catastrophic storm (reflecting the costs associated with the Hunter Valley storms), the AER considers that it is not possible to develop an alternative self insurance premium for catastrophic storms from the information provided by SAHA. In particular, the AER considers that it is not able to develop a reasonable probability of occurrence based on the information provided since:

- no cost (or SAIDI) information is provided in the data in relation to other storms. It is therefore not possible to determine if previous storms were catastrophic as defined by SAHA
- SAHA questioned the robustness of the data provided, indicating that there is insufficient information provided in the EMA Disaster Database and that it is virtually impossible to use the database to determine the impact of large scale storms beyond the last 10 years[1447]
- it is not clear that maximum wind gusts are necessarily indicative of a catastrophic storm (maximum wind gusts do not form part of the definition of a catastrophic storm as defined by SAHA). Further:
  - the Casino storm in 2001 registered winds up to 140km/hr[1448], but was not identified by Country Energy as a catastrophic storm

[1444] Based on an average of maximum wind gusts of 135 km/h at Norah Head and 124 km/hr at Newcastle – SAHA report, confidential, p.44 and http://www.bom.gov.au/weather/nsw/sevwx/0607summ.shtml

[1445] GeoScience Australia *A Statistical Model of Severe Winds*, 2007, p. 48. http://www.ga.gov.au/image_cache/GA10911.pdf.

[1446] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 45.

[1447] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 43.

[1448] SAHA, *Response to the AER's Draft decision – self insurance,* confidential, p. 44.

- the Hunter Valley storm of 1998 recorded winds of 150km/hr[1449], but was not previously identified by EnergyAustralia as a catastrophic storm.

Based on the assessment above, the AER is not satisfied that the self insurance premium for a catastrophic storm reflects the efficient costs that a prudent operator in the circumstances of Country Energy and EnergyAustralia would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in the regulatory proposals and the revised regulatory proposals.

Summary

The AER maintains its draft decision and does not accept the self insurance allowance for Country Energy and EnergyAustralia for damage to poles and lines as a result of a catastrophic storm. Accordingly, the AER does not accept the proposed self insurance premiums of $279 000 per annum for Country Energy and $763 000 per annum for EnergyAustralia.

Key assets

Country Energy and EnergyAustralia proposed the following self insurance premiums for the failure of key assets:

- Country Energy—$2.76 million per annum
- EnergyAustralia—$2.69 million per annum.

This self insurance claim relates to the failure of power transformers, distribution transformers and circuit breakers, and the associated costs for the DNSPs, including third party claims.

In the draft decision, the AER accepted the self insurance premiums for Country Energy and EnergyAustralia for costs associated with the failure of power transformers, distribution transformers and circuit breakers. However, the AER did not accept EnergyAustralia's self insurance claim in relation to above deductible costs for consequential third party damage as a result of asset failure. The AER rejected SAHA's proposed probability of 1 in 11 years for such an event on EnergyAustralia's network on the basis that SAHA had provided no information in support of this conclusion.

In response, SAHA suggested that the AER rejected the self insurance allowance for third party claims on the basis that EnergyAustralia had never experienced such an event.[1450] SAHA indicated that it is difficult to quantify this risk, but believed that its probability and consequence estimates were reasonable, and moreover, that its estimates were more reasonable than a zero self insurance allowance as proposed by the AER.[1451]

[1449] EMA Disasters Database, available: http://www.ema.gov.au/ema/emadisasters.nsf/6a1bf6b4b60f6f05ca256d1200179a5b/3b219e6acb810a48ca256d3300057f80?OpenDocument

[1450] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 47.

[1451] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 47.

The AER notes that it did not reject the proposed premium on the basis of no historical information, rather, the AER rejected the premium on the basis that there was no information provided in the regulatory proposal on which to determine that the premium was reasonable. In its original report, SAHA's argument for the adoption of a 1 in 11 year probability for such an event consisted of a statement that, notwithstanding that there have been no previous claims:[1452]

> SAHA considers it reasonable to assume that there can potentially be one future incident during next regulatory period that can have an above deductible impact on 3rd party properties. Translating this assumption, there is a 1 in 11 years (since EnergyAustralia inception) probability of this above deductible consequential 3rd party damage occurring.

The AER agrees that this risk may well exist for EnergyAustralia, however, based on the limited information provided, the AER is unable to accept that the 1 in 11 year probability adopted by SAHA is reasonable. SAHA has provided no rationale for the adoption of this particular probability.

In response to SAHA's argument that the calculated premium is more reasonable than the zero premium provided by the AER in the draft decision, the AER does not consider that this constitutes a sufficient rationale in support of the 1 in 11 year probability adopted by SAHA.

Based on the assessment above, the AER is not satisfied that the self insurance premium for third party claims arising from key asset failure, reflect the efficient costs that a prudent operator in the circumstances of EnergyAustralia would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in the regulatory proposals and the revised regulatory proposals.

Summary

The AER maintains its draft decision and does not accept the forecast self insurance allowance for EnergyAustralia for third party claims arising from key asset failure. Accordingly, the AER does not accept the proposed self insurance premium for EnergyAustralia.

The AER accepts Country Energy's and EnergyAustralia's self insurance premiums of $2.76 million per annum and $2.68 million per annum respectively for the risk of key asset failure.

Key person risk

The NSW DNSPs have proposed the following self insurance premiums for key person risk:

- Country Energy—$42 000 per annum
- EnergyAustralia—$219 000 per annum
- Integral Energy—$119 000 per annum.

[1452] SAHA, *EnergyAustralia Self Insurance Risk Quantification*, confidential, p. 130.

Key person risk represents the risk that a DNSP could bear an adverse financial impact due to the 'sudden departure, or death', of a key employee.

In the draft decision, the AER did not accept the self insurance premiums, indicating that:

- it was not satisfied that a prudent operator would seek insurance for the sudden departure or death of such a large number of its employees
- it was not satisfied that the coverage of a simultaneous event of the magnitude of this type would be possible
- the analysis provided by SAHA was not supported by information concerning the history of sudden departure or death of employees from either the NSW DNSPs or similar businesses (being based on the experience in Victorian electricity businesses)
- the self insurance premiums are calculated on the basis of the sudden departure or death of all key employees identified by the NSW DNSPs. The AER notes, however, that in any year it would be expected that only a fraction of these key employees would suddenly depart or die.

In its response to the draft decision, SAHA indicated that:[1453]

- It would be inappropriate to impose a limit on, or to apply a standard percentage across the board for the number of key persons a regulated business is allowed to have. This is because the number of key persons for a company is uniquely influenced by its business model, market availability, operation locality and human resource activities.
- The calculation of premiums is conducted at the individual key person level rather than all persons leaving in a single year. The risk premium estimated for key person risk is therefore the sum of the cost for each key person in the organisation.
- Allowances for key person risk have been approved within other industries within Australia, and also by the AER. SAHA noted that, the Australian Competition Tribunal varied the ACCC's amended revision to the Access Arrangement in relation to GasNet to allow for key person risk. Further, in the final decision for SP AusNet released in January 2009, the AER accepted the proposed risk premium for key person risk and noted that the methodology used in the quantification of this risk is identical to the current proposed method.

The AER is aware of the previous acceptance of key person risk as a self insurance event. The AER notes, however, that its draft decision did not reject key person risk as a potentially self–insurable event, but rather did not accept the proposed premiums on the basis of its understanding of the information provided. The AER acknowledges that key person risk is a legitimate self insurance risk.

In relation to the calculation of premiums, the AER accepts SAHA's point that the calculation is conducted at the individual key person level rather than all persons leaving in a single year.

As noted in the draft decision, the AER is concerned with the large number of employees classified as key persons.[1454] While SAHA suggested that '…it would be inappropriate to

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[1453] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, pp. 48–49.

impose a limit on, or to apply a standard percentage across the board for the number of key persons a regulated business is allowed to have', the AER considers that only those employees that are genuinely 'key' to the business should be insured. Accordingly, the AER considers that the definition of a key person must be both clear and reasonable to ensure that self insurance is provided for key persons only.

SAHA indicated that key person risk represents the risk that the DNSP could bear an adverse financial impact due to the sudden departure, or death, of a key employee.[1455] SAHA further suggested that employees should be regarded as key people to the extent that their sudden departure or death would adversely affect the financial position of the company due to:[1456]

- difficulty in replacing the person in the short term
- their replacement is likely to be from overseas or interstate
- considerable additional expenses incurred in recruitment, relocation and settlement costs of a replacement
- loss of income, or increased costs, over and above that assumed in the regulatory submission, would follow from the disruption to the company's core business and the time required for the replacement to understand the company's processes and strategies.

SAHA therefore calculated the self insurance premium associated with each identified key employee based on the calculated financial exposure due to the loss and the probability of that key person leaving.[1457] SAHA indicated that the financial impact of the loss of a key person reflected the additional replacement cost involved in replacing the key person and any business disruption cost.[1458]

Whilst it is possible to identify a significant number of key persons within an organisation, the AER considers that it is not necessarily the case that key person insurance should be obtained for each of these persons. The AER notes that an important component of identifying a key person for the purposes of key person insurance relates to the impact that the loss of that person would have on the financial position of the business. This is confirmed by the definition of key person insurance provided by a number of insurance providers, for example:

- The loss of a key person from a business '…could result in a significant impact on revenue, profit or other financial aspects of a business'[1459]
- 'The sudden loss, via death or disability (of a key person) could have a significant financial impact on the business'[1460]

[1454] Country Energy identified over 900 key persons, EnergyAustralia identified over 250 and Integral Energy identified over 160.

[1455] SAHA, *Country Energy Self Insurance Risk Quantification*, confidential, p. 92.

[1456] SAHA, *Country Energy Self Insurance Risk Quantification*, confidential, p. 93.

[1457] SAHA, *Country Energy Self Insurance Risk Quantification*, confidential, p. 93.

[1458] SAHA, *Country Energy Self Insurance Risk Quantification*, confidential, p. 95.

[1459] AXA Advantage, available: http://www.axaadvantage.com.au/adv/adv.nsf/AttachmentsByTitle/AXAProd_PersInsTechInsGuide.pdf/$FILE/AXAProd_PersInsTechInsGuide.pdf p. 42.

- ‘This type of insurance is designed to protect a business in the event of the loss of a person who makes a significant contribution towards the profitability of the business’.[1461]

The AER considers that the financial impact to the NSW DNSPs should be significant for an individual to be considered for key person insurance. If this was not the case then presumably key person insurance could be provided for a significant number of employees on the basis that they would be difficult to replace and their loss would have an adverse financial impact. Therefore, the main issue is whether the potential financial loss associated with an individual is significant enough to warrant obtaining key person insurance for that person.

Based on the analysis provided by SAHA, the AER considers that the financial loss associated with the individual key persons identified for the NSW DNSPs is not significant. The potential financial losses associated with individual key persons identified by each of the NSW DNSPs (in dollar terms and as a percentage of forecast 2008–09 revenues) is provided in table M.1.

Table M.1: Potential financial losses associated with individual key persons

DNSP	Financial loss per person ($)	Financial loss per person (% of 2008–09 revenue)
Country Energy	1597 to 27 250	0.0002 to 0.0040
EnergyAustralia	48 296	0.0050
Integral Energy	28 041 to 84 703	0.0040 to 0.0100

Source: SAHA, *Country Energy Self Insurance Risk Quantification*, confidential, p. 95; SAHA, *EnergyAustralia Self Insurance Risk Quantification,* confidential, p. 96; and SAHA, *Integral Energy Self Insurance Risk Quantification,* confidential, p. 91.

In contrast to the values in table M.1, the AER notes that the potential financial losses associated with individual key persons identified in the ACCC’s GasNet decision ranged between $120 000 and $700 000 per person (0.15 per cent and 0.8 per cent of GasNet’s allowed 2003 revenue).[1462]

Based on the minimal financial impact associated with the individual persons identified by the NSW DNSPs, the AER considers that it is not possible to define these individuals as key persons for the purposes of applying key person insurance. The AER considers, therefore, that the persons identified by each of the NSW DNSPs are not eligible for self insurance.

[1460] http://www.anz.com/aus/corporate/Products-And-Services/Insurance-And-Superannuation/Insurance/Key-Person/default.asp.
[1461] http://www.apesma.asn.au/services/insurance/key_person_insurance.asp.
[1462] Based on confidential self insurance information provided in Annexure 7 of the GasNet Australia, Access arrangement submission, March 2002 and the 2003 revenue allowance from http://www.aer.gov.au/content/item.phtml?itemId=679335&nodeId=8b978fc92d464ae4e13de85dd75fb90b&fn=ACCC’s%20revised%20access%20arrangement%20information%20for%20GasNet%20(17%20January%202003).pdf.

Notwithstanding the above, the draft decision indicated that key person risk represented the risk that a DNSP could bear an adverse financial impact due to the 'sudden departure, or death' of a key employee. This definition was provided by SAHA in its 'description of risk' section and the key person risk section of the original report. The AER notes that numerous insurers provide key person insurance. However, these insurers define key person risk as the risk associated with unexpected illness, injury or death of a key person.[1463] In particular, AXA indicate that key person insurance is essentially life, total permanent disability or trauma insurance policies taken out by a business on the life of a key person.[1464] The AER notes that resignation of a key person is not considered a component of this insurance risk.

The AER indicated that the analysis provided by SAHA was not supported by information concerning the history of sudden departure or death of employees from either the NSW DNSPs or similar businesses—SAHA indicated that it derived the average probability of each member of a DNSP's key person list leaving the service of the DNSP using resignation, mortality and disablement factors referenced to an *Actuarial Review of the Victorian Energy Industry Superannuation Fund*.[1465]

Such an approach does not appear to be consistent with the definition of key person risk provided by SAHA (i.e. 'sudden departure or death' of an employee) or used by other insurance providers. Key person risk relates only to risk associated with unexpected illness, injury or death to key personnel—not resignation. The information relied on and provided by SAHA does not specifically relate to illness, injury or death, but relates to all departures including resignations. The AER considers, therefore, that the probability calculations derived by SAHA are inappropriate. Based on the limited information provided by SAHA, the AER is unable to determine an alternative probability associated with death and disablement only.

The AER accepts key person risk as a legitimate self insurance risk, however, based on the above, the AER is not satisfied that the self insurance premium for key person risk reflects the efficient costs that a prudent operator in the circumstances of the NSW DNSPs would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in the regulatory proposals and the revised regulatory proposals.

Summary

The AER maintains its draft decision and does not accept the self insurance premiums for key employees of $42 000 per annum for Country Energy, $219 000 per annum for EnergyAustralia and $119 000 per annum for Integral Energy.

1463 See for example http://www.anz.com/aus/corporate/Products-And-Services/Insurance-And-Superannuation/Insurance/Key-Person/default.asp; and http://www.newcastlepermanent.com.au/Business/Insurance/KeyPersonInsurance/tabid/150/Default.aspx and http://www.iselect.com.au/life-insurance-australia/key-person.jsp?ref=L_S_G_key_person_insurance.

1464 AXA Advantage, available: http://www.axaadvantage.com.au/adv/adv.nsf/AttachmentsByTitle/AXAProd_PersInsTechInsGuide.pdf/$FILE/AXAProd_PersInsTechInsGuide.pdf.

1465 SAHA, *Country Energy Self Insurance Risk Quantification*, confidential, p. 95.

General public liability

General public liability risk covers incidents where a DNSP is liable for injuries or other losses suffered by members of the general public as a result of its (or its employees) negligence or fault. EnergyAustralia and Country Energy sought self insurance in relation to general public liability for claims above the existing external insurance deductible.[1466] Country Energy and EnergyAustralia have both proposed self insurance premiums of $9000 per annum.

In its original report, SAHA indicated that Integral Energy had been affected by this risk twice in the last five years and therefore adopted a 2 in 11 year probability of such an event for Country Energy and EnergyAustralia.[1467]

In the draft decision, the AER did not accept the self insurance claims for Country Energy and EnergyAustralia, stating that it considered that the basis for determining the probability of these events was not robust. In particular, the AER noted:

- Integral Energy's recent experience with above deductible general liability claims is not relevant to EnergyAustralia or Country Energy, because of differences between Integral Energy's network and circumstances and those of Country Energy and EnergyAustralia
- there is no rationale for the application of an 11 year period as the basis for the probability calculation because there is nothing inherently important about the inception date of the DNSPs.

In its response to the AER, SAHA suggests that general public liability is a credible risk that could affect each business at some point in the future, and therefore should be included as a self insured risk premium.[1468]

As previously discussed, the AER's role is not to identify potential risks faced by a DNSP, but is to assess the proposed operating costs (self insurance premiums). Accordingly, the AER is not concerned whether or not an event is possible, but rather, whether the premium is reasonable based on the evidence provided.

In relation to the AER's issues associated with the application of Integral Energy's experience with such claims to other DNSPs, SAHA suggests that '(i)t would be preferable if the AER could clearly outline what these differences (between the DNSPs) are, and how they would lead them to believe that none of the other businesses could ever be exposed to this risk'.[1469]

As indicated, the AER has not concluded that these businesses could never be exposed to such risks, but rather, that it cannot accept the self insurance premium based on the information provided. The AER considers that, in the first instance, the onus is on the DNSP to justify the application of the experience of Integral Energy to its business, identify the factor inherent in their businesses vis-à-vis Integral Energy, and explain the application of this relationship in developing the 2 in 11 year probability. It is not sufficient to suggest that since an event has impacted another DNSP that it is therefore

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1466 Integral Energy did not seek self insurance for general public liability risk.

1467 See for example SAHA, *Country Energy Self Insurance Risk Quantification*, confidential, p. 80.

1468 SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 50.

1469 SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 50.

likely to impact the business in question. Further, the AER does not consider that it is reasonable to apply a probability to such an event without explaining the considerations undertaken in developing that probability.

SAHA also suggested that the application of a 2 in 11 year probability represented a discount to the Integral Energy probability (2 in 5 year), stating that '…based on the evidence that whilst Country Energy and EnergyAustralia have never recorded such an event, this was a real and credible risk that could affect these businesses going forward, and therefore, they should be compensated based on a best central estimate of this risk.[1470]

The AER has received no evidence to support that the calculated probability is the 'best' estimate or even reasonable, since no information has been provided by SAHA to clarify the relationship between the 2 in 5 year probability experienced by Integral Energy and the 2 in 11 year probability applied to EnergyAustralia and Country Energy. It is not clear from the SAHA analysis, for example, why a probability of 1 in 25 years or 1 in 50 years may be more appropriate for EnergyAustralia or Country Energy.

Based on the above, the AER is not satisfied that the self insurance premium for general public liability for claims above the existing external insurance deductible reflect the efficient costs that a prudent operator in the circumstances of EnergyAustralia and Country Energy would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in the regulatory proposals and the revised regulatory proposals.

Summary

The AER maintains its draft decision and does not accept the forecast self insurance allowance for general public liability risk for Country Energy and EnergyAustralia. Accordingly, the AER does not accept the proposed self insurance premium of $9 000 per annum for Country Energy and EnergyAustralia.

Guaranteed service level compensation

EnergyAustralia sought self insurance for guaranteed service level (GSL) claims in relation to a major outage due to:

- increased uptake of GSL claims
- bushfires started by EnergyAustralia's assets
- aged asset failure
- unforeseeable human error.

EnergyAustralia proposed a self insurance premium of $251 000 per annum.

In the draft decision, the AER rejected the self insurance premium on the basis that the probability associated with a major bushfire started by EnergyAustralia's assets was not appropriately calculated (see the discussion on major bushfires above) and that SAHA had provided no evidence in support of the proposed probabilities associated with asset

[1470] SAHA, *Response to the AER's Draft decision – self insurance*, confidential, p. 50.

failure or human error causing a catastrophic power failure, and were therefore considered not to be sufficiently robust to be used to calculate the premium.

In response to the draft decision, SAHA noted that:

- the AER did not provide an explanation in rejecting the estimated annualised cost of claims incurred by EnergyAustralia between 2006 and 2008
- the AER's main driver for coming up with its conclusion was that SAHA has not provided a robust assessment of the risk scenarios appears to be due to the fact that EnergyAustralia has not previously experienced an incident. SAHA suggested that acknowledgement of this fact is represented in the very low, but non zero probability of such a risk occurring.

SAHA noted that the scenarios represent a real risk to EnergyAustralia and that compensation should still be provided for bearing this risk, based on an unbiased estimate of the cost. SAHA suggested that this approach is consistent with what a 'reasonable' practitioner would adopt, and that a 'prudent operator', operating a similar network to EnergyAustralia's, would and must manage this risk.

SAHA also indicated that the GSL payment meets the criteria of a regulatory payment defined by the NEL. Similarly, EnergyAustralia noted that there is no evidence that the AER has appropriately taken into account the NEL revenue and pricing principles. In particular, it noted that the AER had rejected the definition of guaranteed service level payments without reference to section 7A(2)(b) of the NEL.[1471]

The draft decision rejected the premium on the basis of the information provided rather than addressing the appropriateness of including such payments in a self insurance allowance. However, EnergyAustralia and SAHA have provided additional information citing specific sections of the NEL and suggesting that the provision of a self insurance allowance for GSL payments is consistent with the NEL. SAHA and EnergyAustralia have requested that the AER specifically address the relevant NEL requirements in its considerations.

SAHA and EnergyAustralia argued that recoupment of GSL costs is provided for under the NEL. Specifically, SAHA and EnergyAustralia indicated that a GSL payment is a regulatory payment consistent with section 2E of the NEL:

> A regulatory payment is a sum that a regulated network service provider has been required or allowed to pay to a network service user or an end user for a breach of, as the case requires—
>
> (a) a distribution reliability standard or transmission reliability standard; or
>
> (b) a distribution service standard or transmission service standard, because it was efficient for the regulated network service provider (in terms of the provider's overall business) to pay that sum.

Since a GSL payment is a regulatory payment, SAHA argued, therefore, that EnergyAustralia should be given a reasonable opportunity to recover such a cost as outlined in section 7A(2)(b) of the NEL:

[1471] EnergyAustralia, *Revised regulatory proposal*, p. 104.

> A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in complying with a regulatory obligation or requirement or making a regulatory payment.

The AER has considered the application of section 2E of the NEL and is of the view that GSL payments, in some circumstances, are regulatory payments within the definition in the NEL. In the circumstances where making a GSL payment for breach of a distribution service standard is more efficient than altering the network in order to comply with the distribution service standard, the GSL payment appears to satisfy paragraph (b) of section 2E of the NEL. Where a GSL payment is made for a breach of a service standard that occurs due to business mismanagement rather than efficient planning considerations, that payment is less likely to satisfy the NEL definition of a regulatory payment.

The AER is required by section 16 of the NEL to take into account section 7A(2)(b) of the NEL when exercising a discretion in making a distribution determination. Section 7A(2)(b) of the NEL provides that DNSPs should be given a reasonable opportunity to recover at least the efficient costs of making a regulatory payment. Therefore, in making a decision on EnergyAustralia's opex allowance, the AER must take into account that EnergyAustralia should be given a reasonable opportunity to recover at least the efficient costs of making GSL payments. In light of these NEL provisions, the AER considers that EnergyAustralia should be granted an allowance to recover the efficient costs of GSL payments that are made in the context of efficient network planning.

Based on an assessment of the NEL, the AER considers that EnergyAustralia is entitled to claim efficient GSL payments through self insurance. The AER is required therefore to determine if the proposed self insurance premium reflects the efficient costs that a prudent operator in the circumstances of the EnergyAustralia would require to achieve the opex objectives.

In relation to the anticipated growth in the uptake of GSL claims, the AER acknowledges that it overlooked this issue in assessing the original self insurance proposal. However, having examined the annualised GSL claims provided by EnergyAustralia for the financial years 2006 to 2008 and the forecast growth in the uptake of GSL claims, the AER considers that the methodology applied by SAHA is reasonable. Accordingly, the AER accepts the self insurance premium of $52 000 per annum associated with the increased uptake of GSL claims and the consequent GSL payments.

The AER notes that it did not reject the proposed self insurance premiums in relation to major bushfires, aged asset failure and unforeseeable human error on the basis of no historical information, rather, the AER rejected the premiums on the basis that there was no information provided in the regulatory proposal on which to determine whether the premiums were reasonable.

The AER notes that SAHA did not provide additional information in relation to major bushfires, aging assets and unforeseeable human error, but indicated that the absence of historical information was reflected in the very low probability of occurrence attached to these events.

In relation to a major bushfire ignited by EnergyAustralia's assets, the AER identified issues associated with the probability calculation in the bushfire section above. It is possible for the AER to apply a substitute probability for a major fire caused by a DNSP's assets of 1 in 68 years[1472] to calculate an alternative premium, however, it is not clear to the AER that such a major bushfire would not be deemed a natural disaster under the DNSP's licence conditions and thus an excluded interruption event. [1473] In response to questions from the AER, EnergyAustralia indicated that, whilst it is possible for such a bushfire to be an eligible natural disaster under the *Natural Disaster Relief Arrangements* (and thus an excluded interruption event), the threshold for receiving such relief was high.[1474] EnergyAustralia indicated, therefore, that it was possible for a bushfire to be classified as a major bushfire (causing more than $10 million in damage to EnergyAustralia's network) but be below the relief threshold and therefore not an excluded interruption event. In this case, EnergyAustralia would be liable for the associated GSL payments.

The AER accepts this point but notes that the risk that EnergyAustralia is seeking to self insure is the risk that a major bushfire ignited by its assets does not invoke a relief claim (and is therefore not classified as an excluded interruption event). While it is possible for the AER to determine the probability of a major bushfire ignited by EnergyAustralia's assets (based on information provided in the regulatory proposal), no information concerning the likelihood of such a bushfire not invoking a relief claim has been provided by EnergyAustralia. Accordingly, it is not possible for the AER to determine an alternative probability based on the information provided.

The AER therefore rejects the proposal for self insurance associated with GSL payments as a result of a major bushfire caused by EnergyAustralia's assets.

In terms of the self insurance premium associated with asset failure leading to catastrophic blackout, SAHA noted that not all major failures will result in a catastrophic blackout and EnergyAustralia has in place a maintenance and replacement regime to minimise and prevent the failure of aged assets. Therefore, SAHA has assumed a relatively rare occurrence of this event at 1 in every 150 years.[1475] Similarly, in relation to GSL claims as a result of human error, SAHA indicated that it applied a relatively rare occurrence of this event at 1 in every 300 years.[1476]

The AER notes that SAHA has provided no additional information in support of the probability assumptions for aged asset failure and human error. While the AER accepts that these are possible risks faced by EnergyAustralia, the AER is unable to determine whether the probabilities and associated premiums are reasonable based on the information provided above.

On the basis of this analysis, the AER concludes that it is not satisfied that the self insurance premiums associated with these events reflect the efficient costs that a prudent

[1472] Based on information provided by SAHA as discussed in the bushfire section above.

[1473] See the Licence conditions at: http://www.ipart.nsw.gov.au/files/Design%20Reliability%20and%20Performance%20Licence%20Conditions%20for%20DNSPs%20-%2023%20November%202007.PDF, p.24; and The Natural Disaster Relief and Recovery Arrangements at: http://www.ema.gov.au/agd/EMA/rwpattach.nsf/VAP/(756EDFD270AD704EF00C15CF396D6111)~NDRRA+Determination+2007.doc/$file/NDRRA+Determination+2007.doc

[1474] EnergyAustralia, email to the AER, 27 February 2009.

[1475] SAHA, *EnergyAustralia Self insurance risk quantification*, confidential, p. 146.

[1476] SAHA, *EnergyAustralia Self insurance risk quantification*, confidential, p. 147.

operator in the circumstances of EnergyAustralia would require to achieve the opex objectives.

The AER notes that it is unable to derive a substitute premium for this risk due to the lack of supporting information provided in the regulatory proposals and the revised regulatory proposals.

Summary

The AER accepts the proposed self insurance of $52 300 per annum associated with the increased uptake of GSL claims and the consequent GSL payments. However, the AER maintains its draft decision and does not accept the self insurance allowances for EnergyAustralia for GSL claims in relation to major bushfires, aging assets and unforeseeable human error. Accordingly, the AER does not accept the proposed self insurance premiums associated with these events of $199 000 per annum for EnergyAustralia.

Risks which should be treated as pass through events

SAHA and Country Energy raised the prospect of an earthquake risk being covered under a cost pass through arrangement. SAHA noted that whilst such an event may be defined as a cost pass through event, the materiality threshold associated with any cost pass through application, means that on average, the affected regulated business will not be fully compensated for bearing this negative asymmetric risk. Therefore, SAHA suggested that a self insurance quantification best addressed the risk of a magnitude six earthquake.[1477]

The AER considers that the choice between managing an event through self insurance or cost pass through should reflect the nature of the event. For example, such a decision should rely primarily on whether the frequency and cost associated with an event can be robustly determined and whether the event would result in catastrophic losses to the business. The materiality threshold applied to a cost pass through event is not regarded a relevant consideration in this context.

For a number of risks including earthquakes, the impact of catastrophic storms and major bushfires, the AER notes that it is difficult to derive a self insurance premium because of the low frequency of these events and the potential for catastrophic losses. For the following risks the AER considers that they should be dealt with under the pass through provisions of the transitional chapter 6 rules:

- earthquakes above magnitude six
- a major bushfire ignited by the DNSP’s own assets (not covered under insurance or in the DNSP’s baseline opex)
- a major bushfire ignited by a third party (not covered under insurance or in the DNSP’s baseline opex)
- damage to poles and lines as a result of a catastrophic storm (not covered under insurance or in the DNSP’s baseline opex).

[1477] SAHA, *Response to the AER’s Draft decision – self insurance*, confidential, p. 27.

The treatment of these events under the pass through provisions of the chapter 6 transitional rules is discussed in chapter 15 of this final decision.

Administrative arrangements

The AER notes the NSW DNSPs recognise the amount of self insurance expenditure in their regulatory accounts and allocate the operating expense according to approved cost allocation methods.[1478] However, the NSW DNSPs do not have any reporting (recognition or disclosure) arrangements in place to account for the risk they are bearing in connection with self insured events.

The future obligation that arises from a commitment to self insure events is not like other operating expenses. Self insurance is different in nature to other opex, in that the AER is approving opex now in lieu of the efficient cost of an external insurance premium. However, the expectation is that in approving the opex allowance for self insurance the NSW DNSPs cover the cost of the self insured event, when that event occurs at a future date. The AER considers that the risk of meeting the costs of an event should it arise needs to be disclosed.

The AER understands that the current guidance in the Australian Accounting Standards Board 137 Provisions, Contingent Liabilities and Contingent Assets (AASB 137), prohibits a provision being recognised if there is no present obligation, no probable outflow of resources and no reliable estimate of the amount of the obligation.[1479] Under these criteria self insurance events cannot be a recognised as a provision with reference to AASB 137.

The AER notes that self insurance events are similar in nature to contingent liabilities which are defined under AASB 137 as a possible obligation that arises from past events and whose existence will be confirmed only by the occurrence or non occurrence of one or more uncertain future events not wholly within the control of an entity.[1480] The standard describes contingent liabilities as liabilities that are not recognised as they are either a possible obligation which is yet to be confirmed or a present obligation which cannot be reliably estimated or is not probable.[1481]

AASB 137 does not require that contingent liabilities are recognised,[1482] but it does require that certain disclosures are made in the financial accounts of the entity which are responsible for bearing the risk of these liabilities.

As part of the administrative arrangements for self insurance, the AER considers it is prudent practice for the NSW DNSPs to disclose self insurance events each regulatory year and provide a brief description of the nature of the self insurance event in accordance with AASB 137. The standard also requires, where practical, disclosure of:

- an estimate of the financial effect of the liability
- an indication of the uncertainties relating to the amount or timing of the outflow

[1478] Integral Energy, email to the AER, 6 March 2009; EnergyAustralia, email to the AER, 17 March 2009 and Country Energy, email to the AER, 18 March 2009.
[1479] AASB 137 *Provisions, Contingent Liabilities and Contingent Assets*, paragraph 14.
[1480] AASB 137, paragraph 10.
[1481] AASB 137, paragraph 13 (b).
[1482] AASB 137, paragraph 27.

- the possibility of any reimbursement.[1483]

Accordingly, the AER requires the NSW DNSPs to disclose self insurance events as a contingent liability in accordance with AASB 137 in their audited accounts.

AER conclusion

For the reasons set out above, the AER considers that the proposed self insurance allowances do not reflect the efficient costs that prudent operators, in the circumstances of the NSW DNSPs, would require to meet the opex objectives. Accordingly, under clause 6.5.6(d) of the transitional chapter 6 rules, the AER has not accepted the forecast self insurance allowances. Further, consistent with the requirements of clause 6.12.1(4)(ii) of the transitional chapter 6 rules, the AER has provided substitute values for the associated self insurance premiums.

For the reasons discussed and as a result of the AER's analysis of the revised regulatory proposals, the AER is satisfied that the amended estimates of the total self insurance allowances for the next regulatory control period set out in table M.2, based on the above accepted self insurance premiums and substitute values, reasonably reflects the opex criteria, including the opex objectives. In coming to this view the AER has had regard to the opex factors.

Table M.2: AER conclusion on self insurance allowances for the NSW DNSPs ($m, 2008−09)

	Country Energy		EnergyAustralia		Integral Energy	
	Revised regulatory proposal	AER final decision	Revised regulatory proposal	AER final decision	Revised regulatory proposal	AER final decision
Total self insurance	19.5	15.0	29.5	20.6	16.1	9.6

Note: EnergyAustralia's self insurance premiums in its regulatory proposal are in 2007−08 dollar terms. The AER converted these to 2008–09 dollar terms using EnergyAustralia's proposed 2.7 per cent escalation.

[1483] AASB 137, paragraph 86.

Appendix N: 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.

Debt raising costs

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.[1484] 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.[1485] In the revised regulatory proposals, a report by CEG is referenced and submitted by all six NSPs—that is, all submitted versions are identical.[1486] TransGrid and EnergyAustralia both submitted an additional report by Tony Carlton, from the University of NSW, although there are some variations between the two versions.[1487] Further, EnergyAustralia's submission requested that all reports and supporting documents which it had submitted as part of its regulatory proposal and

[1484] 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.

[1485] 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.

[1486] 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.

[1487] 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.

revised regulatory proposal be considered by the AER in making its final determination for all the NSPs.[1488]

Other relevant submissions were also received by the AER, from the following organisations:

- TransGrid—a report by the Strategic Finance Group (SFG)[1489]
- Powerlink—regarding aspects of the draft decision for TransGrid[1490]
- 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 regulatory proposal).[1491]

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.[1492]

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.[1493]

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.[1494]

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:

[1488] EnergyAustralia, *Submission on other network service providers*, 16 February 2009.
[1489] SFG, *Debt and equity issuance costs for a benchmark transmission business*, 20 March 2009.
[1490] Powerlink, *Draft Decision TransGrid Transmission Determination 2009–10 to 2013–14*, 16 February 2009.
[1491] 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.
[1492] This approach is essentially the same as that employed by the AER for its draft decisions.
[1493] 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.
[1494] 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.

- 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.[1495]
- 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.[1496]

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.

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.[1497] All of the NSPs rejected the draft decision on this issue and resubmitted[1498] the 3 bppa indirect cost allowance in their revised regulatory proposals.[1499] 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:[1500]

> 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.

[1495] 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.

[1496] 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.

[1497] 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.

[1498] 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.

[1499] 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.

[1500] 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 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.'

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:[1501]

> 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.[1502]

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:[1503]

> 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.[1504]

For debt issues, CEG stated that there is a simple relationship between yield and price:[1505]

> In the case of debt, a lower price implies a higher interest rate.

The AER further notes that Associate Professor Handley highlighted the key issue that distinguishes debt underpricing from equity underpricing:[1506]

> …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.

[1501] 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.

[1502] 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.

[1503] CEG, January 2009, p. 45, paragraph 150.

[1504] For example, see EnergyAustralia, *Revised regulatory proposal*, p. 106 and TransGrid, *Revised revenue proposal*, p. 78.

[1505] CEG, January 2009, p. 44, paragraph 149.

[1506] Handley, J. C., *A note on the costs of raising debt and equity capital*, 12 April 2009, p. 15.

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:[1507]

> 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:[1508]

> 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.’[1509] CEG stated in similar terms that:[1510]

> 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,[1511] Carlton and CEG) have submitted reliable evidence that debt underpricing exists.

[1507] Handley, April 2009, p. 17.

[1508] AER, *TransGrid draft decision*, p. 137; AER, *NSW DNSP draft decision*, p. 186; and AER, *Transend draft decision*, p. 190.

[1509] TransGrid, *Revised revenue proposal*, p. 78.

[1510] CEG, January 2009, p. 45, paragraph 150.

[1511] 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.

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'.[1512] 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.[1513] 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.[1514]

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.[1515] 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.[1516] The authors of this paper do not find empirical evidence of underpricing in debt issues, stating:[1517]

> …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.[1518] CEG cited the Saunders et al working paper in its first report, stating:[1519]

> 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:[1520]

> 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]

1512 SFG, March 2009, p. 12.
1513 This point is also made by Handley, April 2009, p. 4.
1514 SFG, March 2009, p. 17.
1515 Carlton, January 2009 (EnergyAustralia), pp. 32–33 and Carlton, January 2009 (TransGrid), pp. 39–41.
1516 Kim, D., Palia, D., and Saunders, A., *The Long–Run Behaviour of Debt and Equity Underwriting Spreads*, Draft Paper, January 2003.
1517 Kim, Palia and Saunders, January 2003, p. 5.
1518 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.
1519 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.
1520 Kim, Palia and Saunders, January 2003, p. 3, footnote 2.

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.[1521] This paper found that offerings[1522] 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.[1523] 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.[1524]

In the draft decisions, the AER stated that there was no evidence that such a trend existed.[1525] 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.

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.[1526]

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.[1527] 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'.[1528] The AER considers that there are other equally plausible

[1521] 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.

[1522] 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.

[1523] 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.

[1524] 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.

[1525] AER, *TransGrid draft decision* p. 137; AER, *Transend draft decision*, p. 190 and AER, *NSW DNSP draft decision*, p. 186.

[1526] CEG, January 2009, pp. 45–46, paragraphs 151–154 (which cite paragraphs 56 and 66 of the May 2008 (TransGrid) CEG report).

[1527] CEG, January 2009, p. 45, paragraph 152.

[1528] CEG, January 2009, pp. 45–46, paragraphs 153–154.

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:[1529]

> 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.

The AER does not consider that the Bortolotti et al paper, which deals solely with equity raising costs, is relevant to debt raising costs.[1530] 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.[1531] Carlton also stated:[1532]

> 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.

1529 EnergyAustralia, *Revised regulatory proposal*, p. 106. A similar statement is made in TransGrid, *Revised revenue proposal*, p. 42, paragraph 141.
1530 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.
1531 Carlton, January 2009 (EnergyAustralia), pp. 32–33; and Carlton, January 2009 (TransGrid), p. 40.
1532 Carlton, January 2009 (EnergyAustralia), p. 33; and Carlton, January 2009 (TransGrid), p. 40.

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.[1533] TransGrid stated that an increase in direct debt raising costs leads to a decrease in indirect debt raising costs, and vice versa.[1534] 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.[1535]

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 comments regarding underpricing had been removed.[1536] The explanation offered by Saunders et al is as follows:[1537]

> 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.

[1533] For example, EnergyAustralia, *Revised regulatory proposal*, p. 107.

[1534] TransGrid, *Revised revenue proposal*, p. 78.

[1535] 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.

[1536] 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.

[1537] Kim, Palia and Saunders, December 2008, p. 977.

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.

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.[1538] 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.

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.[1539] A recommendation was made for the costs of each of these categories, based upon available evidence including Bloomberg and Standard and Poor's data. 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.[1540]

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.[1541] The NSPs, through CEG, relied on a working paper by Saunders, Palia and Kim as an alternative estimate of

[1538] ACG, *Debt and Equity Raising Transaction Costs*, December 2004, pp. 27–53.
[1539] ACG, December 2004, p. 52.
[1540] 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.
[1541] TransGrid, *Revised revenue proposal*, p. 78; Transend, *Revised revenue proposal*, p. 57 and EnergyAustralia, *Revised regulatory proposal*, p. 107.

direct debt raising costs.[1542] 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.[1543]

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:[1544]

- the AER sample contained the same biases as the Saunders et al sample, including US firms and excluding regulated utilities[1545]
- the use of US–based data would produce a lower estimate than Australian–based data, since the market there was more liquid[1546]
- '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.[1547]

The AER refutes the NSPs' claims and notes:

- the ACG data is exclusively based on Australian firms operating in the utilities and infrastructure sectors.[1548] It is incorrect for TransGrid to state that this is not the case, or that 'such data is not publicly available'[1549]
- 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'.[1550]

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:[1551]

> 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.

1542 Kim, Palia and Saunders, January 2003.
1543 AER, *TransGrid draft decision*, p. 138.
1544 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.
1545 TransGrid, *Revised revenue proposal*, p. 77; EnergyAustralia, *Revised regulatory proposal*, p. 106. See also CEG, May 2009, p. 43, paragraph 142.
1546 TransGrid, *Revised revenue proposal*, p. 77; EnergyAustralia, *Revised regulatory proposal*, p. 106. See also CEG, May 2009, p. 43, paragraph 141.
1547 TransGrid, *Revised revenue proposal*, p. 77.
1548 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.
1549 TransGrid, *Revised revenue proposal*, p. 77.
1550 CEG, January 2009, pp. 40–41, paragraphs 135–136.
1551 CEG, January 2009, p. 36, paragraph 119.

A comparison of the main characteristics of the two approaches is included in table N.1, with areas of difference from a benchmark firm shaded on the table.

Table N.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.

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.[1552] 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

[1552] 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.

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.[1553] 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.[1554] 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.[1555] 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 raising costs.[1556] 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, which is 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.[1557]

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

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1553 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.

1554 Kim, Palia and Saunders, 2003, p. 35, table 1.

1555 Kim, Palia and Saunders, 2003, p. 40, table 6.

1556 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.

1557 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.

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:

- the Livingston and Zhou regression supports that the issuance costs of public debt and private debt do not differ
- 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 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.[1558] 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.[1559]

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,[1560] and the debt risk premium on the public bond issued by the benchmark firm.[1561] 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.

[1558] CEG, January 2009, p. 38, paragraph 127.
[1559] Livingston and Zhou, 2002, p. 25, table VIII.
[1560] 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.
[1561] 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.

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*[1562] and *Percentage of Years of Call Protection*,[1563] and miscalculated another, *Log of Issue Frequency*.[1564] The inclusion and correction of these variables in the regression projection[1565] would result in the range of underwriting spreads presented in table N.2.[1566]

Table N.2: Corrected regression projections of gross underwriter spread for each NSP

Issuer	TransGrid	Transend	Country Energy	EnergyAustralia	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 amortised 10–year debt, rather than straight division of five–year debt as per the ACG methodology.[1567] The ACG methodology was based on Australian

1562 Log of proceeds is expressed in $US dollars, so the $AU 200 million benchmark bond size was converted to ln(150).

1563 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.

1564 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).

1565 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.

1566 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.

1567 Separate consideration of the amortisation/straight division issue is provided later in this appendix.

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 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.

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 bppa.[1568] 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.

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.[1569] 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

[1568] Handley, April 2009, p. 30.
[1569] 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 11.5.2 of this final decision.

economic outlook for the Australian economy since mid–2008 has been reflected in official forecasts by Treasury.[1570] 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.[1571]

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 N.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.[1572] Further, the underwriting cost observed for one bank debt issue is not, in isolation, an appropriate benchmark for setting debt raising costs.

1570 The Treasury, *Updated Economic and Fiscal Outlook*, February 2009. Available: http://www.budget.gov.au/2008-09/content/uefo/html/index.htm.

1571 IMF, *World Economic Outlook*, October 2008.

1572 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.

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.

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.[1573]

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.[1574] 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.[1575] 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.[1576] Therefore, if amortisation 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 amortised cost of ten year debt issuance costs would provide a lower allowance than the simple division of five year debt issuance costs.[1577] 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.[1578]

The AER has assessed the evidence presented by the NSPs on amortisation 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:

1573 CEG, January 2009, pp. 47–48, paragraphs 157–166.
1574 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.
1575 ACG, 2004, pp. xvi–xix.
1576 NER, clause 6A.6.2.
1577 AER analysis.
1578 Handley, April 2009, pp. 29–30.

- a new methodology cannot be presented in a revised regulatory proposal unless it is addressing a matter raised in the draft decision
- 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.[1579]

Inflation of debt issuance costs

CEG argued that the non–underwriting transaction costs in debt issues should be indexed for inflation.[1580] 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.[1581]

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.[1582]

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.

[1579] 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.

[1580] CEG, January 2009, p. 49, paragraphs 167–169.

[1581] 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.

[1582] Handley, April 2009, pp. 29–30

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.

Equity raising costs

Rationale for joint consideration

Similar to the approach described 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[1583] 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[1584]
- an allowance for use of retained earnings of 3.8 per cent of retained earnings between normal dividend yield and minimum dividend yield[1585]

[1583] 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.

[1584] 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.[1586]

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[1587]
- TransGrid and EnergyAustralia implemented a 70 per cent dividend payout ratio[1588]
- Integral Energy implemented the 70 per cent dividend payout ratio, but proposed an additional system for tracking imputation credits and compensating the firm.[1589]

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.[1590] 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.[1591] TransGrid and EnergyAustralia also submitted a report by Tony Carlton, although there are some variations between the two versions.[1592] EnergyAustralia submitted a report by Professor Bruce Grundy.[1593] 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.[1594]

Integral Energy submitted a report by KPMG[1595] and comments on cash flow modelling.[1596] TransGrid submitted an additional memorandum by CEG,[1597] as well as a

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1585 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.

1586 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.

1587 Transend, *Revised revenue proposal*, p. 60.

1588 TransGrid, *Revised revenue proposal*, p. 81; and EnergyAustralia, *Revised regulatory proposal*, pp. 48–49

1589 Integral Energy, *Submission to the Australian Energy Regulator 2009 to 2014*, 16 February 2009, p. 10; see also Attachment 3.

1590 CEG, May 2008 (TransGrid); CEG, May 2008 (Transend); CEG, May 2008 (Country Energy), CEG, May 2008 (EnergyAustralia); CEG, April 2008 (Integral Energy).

1591 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.

1592 Carlton, January 2009 (EnergyAustralia); Carlton, January 2009 (TransGrid).

1593 Grundy, B. D., *A Note on the Costs of Equity Financing*, 13 January 2009.

1594 EnergyAustralia, *Submission*, 16 February 2009.

1595 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.

1596 Integral Energy, *Submission*, 16 February 2009.

1597 CEG, *Memorandum on the Ofgem treatment of Equity raising costs*, 18 February 2009.

report by SFG.[1598] The JIA submitted a report by CEG that merges parts of the May 2008 and January 2009 CEG reports with new analysis.[1599]

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.

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:[1600]

> In other words, cash flows should be after company tax, before personal tax, after underpricing costs but before other personal (transaction) 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.[1601] This is in contrast to an allowance for the return on capital, which is separately described in clause 6A.6.2 of the NER for TNSPs and clause 6.5.2 of the

1598 SFG, March 2009.
1599 CEG, November 2008.
1600 Handley, April 2009, p. 10.
1601 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.

transitional chapter 6 rules for the ACT/NSW DNSPs for the next regulatory control period .[1602]

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.[1603] 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.

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.[1604] 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.[1605]

1602 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.

1603 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.

1604 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.

1605 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 transaction costs reflect the indirect cost of a rights issue.[1606]

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.[1607] This is consistent with conventional financial theory.

Officer and Hathaway state:[1608]

> …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:[1609]

> 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 (transaction) costs basis.[1610]

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.[1611] Accordingly, the possible realisation of a capital gain does not require any allowance or offsetting adjustment.

1606 CEG, January 2009, pp. 14–15, paragraph 37–43.

1607 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.

1608 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.

1609 Peirson, G., Brown, R., Easton, S. and Howard, P., *Business Finance: 8th Edition*, McGraw–Hill, 2003, p. 449.

1610 Handley, April 2009, p. 10.

1611 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 entirely irrelevant (see

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[1612] is sold, and that two transactions occur when the non–renounceable right[1613] 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.

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

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.

1612 A renounceable right is one where the existing shareholder can sell their right to purchase additional shares to another investor.

1613 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.

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.[1614] The NER implies a pre–investor level (post–company tax) CAPM and post–company tax (pre–investor tax) revenue model.[1615] This was the point made by Associate Professor Handley when he stated:[1616]

> 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 (transaction) costs basis.

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.[1617] CEG further elaborated on the mechanics of wealth transfer, and provided a detailed appendix on the cost of a rights issue.[1618] 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 sold at a discount, then the value of the shares of the original shareholders is diluted.[1619]

[1614] For example, see TransGrid, *Revised revenue proposal*, p. 80; EnergyAustralia, *Revised regulatory proposal*, pp. 44–45.
[1615] NER, Clause 6.5.3.
[1616] Handley, April 2009, p. 10.
[1617] CEG, January 2009, pp. 14–15, paragraphs 37–43 and Carlton, January 2009 (EnergyAustralia), p. 9.
[1618] CEG, January 2009, pp. 50–52, Appendix A: Costs of a rights issue.
[1619] Carlton, January 2009 (EnergyAustralia), p. 39.

Associate Professor Handley observed that:[1620]

> 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.[1621] 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:[1622]

> 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'.[1623] Similar statements were made by EnergyAustralia.[1624] 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:[1625]

[1620] Handley, April 2009, p. 6.
[1621] Handley, April 2009, p. 8.
[1622] Handley, April 2009, p. 8.
[1623] TransGrid, *Revised revenue proposal*, p. 80.
[1624] EnergyAustralia, *Revised regulatory proposal*, p. 45.
[1625] CEG, January 2009, p. 16, paragraph 45–46.

> …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'.[1626] He cited a paper by Hansen,[1627] 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 transaction costs; risk of failure; arbitrage activity and short selling; and anti–dilution clauses to convertible security holders.[1628]

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:[1629]

> 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.[1630]

The NSPs contended that private placements were used more heavily than rights issues, and are therefore a more appropriate benchmark.[1631] CEG, Carlton and 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.[1632] 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.

1626 Grundy, January 2009, p. 6, paragraphs 17–19.

1627 Hansen, R. *The Demise of the Rights Issue,* The Review of Financial Studies, 1989, vol. 1(3), pp. 289–309.

1628 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).

1629 Handley, April 2009, p. 21.

1630 AER, *TransGrid draft decision*, p. 141; AER, *Transend draft decision*, p. 194; and AER, *NSW DNSP draft decision*, p. 191.

1631 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.

1632 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.

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.[1633] 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.'[1634] Associate Professor Handley also noted the essential equivalence of rights issues and DRPs.[1635]

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 N.4, which is derived from data cited by both CEG and Carlton:

Table N.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 include options, calls, staff plans.

Table N.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.[1636]

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

1633 CEG, January 2009, p. 15–16, paragraph 44; Carlton, January 2009 (EnergyAustralia), pp. 2–7 and Grundy, January 2009, p. 7, paragraph 25.
1634 Carlton, January 2009 (EnergyAustralia), p. 29; Carlton, January 2009 (TransGrid), p. 36.
1635 Handley, April 2009, p. 22.
1636 Handley, April 2009, p. 23.

potential reasons for undertaking an SEO.[1637] 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 N.5 provides the results of the AER's analysis.[1637]

Table N.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.

Table N.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.[1638] 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.

[1637] 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.

[1638] ACG, 2004, p. 4.

Table N.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.[1639] 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.[1640] Empirical research indicates that placements are chosen as an equity raising method by firms under significant financial stress.[1641] 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.[1642] 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 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.[1643] On this basis, Associate Professor Handley noted the AER statement that a discounted rights issue was the optimal SEO method for all circumstances,[1644] but did not

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[1639] 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.

[1640] Carlton, January 2009 (EnergyAustralia), p. 6; Carlton, January 2009 (TransGrid), p. 17.

[1641] 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).

[1642] The AER notes that the price observed is not consistent with the efficient price outcome of both the seller and the buyer being unforced.

[1643] Handley, April 2009, p. 13.

[1644] AER, *TransGrid draft decision*, p. 141; AER, *Transend draft decision*, p. 194 and AER, *NSW DNSP draft decision*, p. 191.

consider it to be 'a strong argument' relative to arguments concerning consistency with the regulatory framework.[1645]

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.[1646] 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 equity issue precipitated the change in price.[1647] The AER notes that announcement effects are not considered an indirect cost by CEG, who stated:[1648]

> 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:[1649]

> 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.

[1645] Handley, April 2009, p. 13.
[1646] Handley, April 2009, p. 5, footnote 9.
[1647] 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.
[1648] CEG, *Memorandum*, February 2009, p. 2.
[1649] Handley, April 2009, p. 5.

It is on this basis that CEG argued that Ofgem's rejection of indirect costs in their 2006 price control review[1650] was a rejection of announcement effects, not underpricing, and therefore irrelevant to the CEG claim for indirect costs. CEG stated:[1651]

> 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.[1652]

The AER notes that Carlton frequently cited announcement effects when discussing the existence of indirect costs. For example:[1653]

> 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[1654] 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, 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.[1655] Eckbo and Masulis conclude that there is 'insufficient evidence to suggest that any of these alternative explanations can resolve the rights offer paradox'.[1656] 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

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[1650] OFGEM, *Transmission price control review: Final proposals*, 4 December 2006.
[1651] CEG, Memorandum, February 2009, p. 3.
[1652] CEG, Memorandum, February 2009, p. 3.
[1653] 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.
[1654] CEG, January 2009, p. 12, paragraph 32.
[1655] Eckbo, B. E. and Masulis, R. W., *Adverse selection and the rights offer paradox*, Journal of Financial Economics, 1992, vol. 32, pp. 293–332.
[1656] Eckbo and Masulis, 1992, p. 295.

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.[1657]

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).[1658] 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 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.[1659] 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[1660]
- 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[1661]

[1657] 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.

[1658] 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.

[1659] TransGrid, *Revised revenue proposal*, p. 81; Integral Energy, *Revised regulatory proposal*, p. 45; and EnergyAustralia, *Revised regulatory proposal*, p. 48.

[1660] CEG, January 2009, p. 29, paragraph 96 and Grundy, January 2009, p. 10, paragraph 36.

[1661] Grundy, January 2009, p. 9, paragraph 34.

- 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[1662]
- use of retained earning delays cash flows to investors, which increases risk[1663]
- 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.[1664]

Accordingly, the NSPs' consultants proposed that a retained earnings allowance needs to be provided to the benchmark firm.[1665] 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:[1666]

> 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:[1667]

> 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.

[1662] CEG, January 2009, pp. 29–30, paragraph 97 and Grundy, January 2009, p. 10, paragraph 35.
[1663] CEG, January 2009, p. 30, paragraph 99.
[1664] CEG, January 2009, p. 30, paragraph 100.
[1665] CEG, January 2009, pp. 31–34, paragraphs 101–115.
[1666] ACG, 2004, p. 63.
[1667] Handley, April 2009, p. 19.

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.[1668] 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.[1669] 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.[1670] 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.[1671] 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.[1672] The AER considers that this result is dependent on the delayed distribution of dividends, in both the initial and later years 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 11 of this final decision.

CEG argued that use of retained earnings incurs costs associated with disrupting investors' preferred portfolios.[1673] The AER notes that this is an argument regarding personal transaction costs, and that such arguments were considered in detail earlier in

[1668] CEG, January 2009, p. 32, paragraph 105.
[1669] CEG, January 2009, p. 29, paragraph 96 and Grundy, January 2009, p. 10, paragraph 36.
[1670] Grundy, January 2009, p. 9, paragraph 34.
[1671] CEG, January 2009, pp. 29–30, paragraph 97; Grundy, January 2009, p. 10, paragraph 35.
[1672] CEG, January 2009, p. 30, paragraph 99.
[1673] CEG, January 2009, p. 30, paragraph 100.

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 regulatory 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.

On this basis, the AER rejects the claim for an allowance for the cost of using retained earnings.

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.[1674] 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'.[1675] This figure was updated by the AER in 2008, consistent with the ACG methodology, to 2.75 per cent.[1676] The ACG methodology only includes rights issues and placements; it does not include dividend reinvestment plans.

[1674] ACG, 2004, pp. 64–69.
[1675] ACG, 2004, p. 65.
[1676] AER, *NSW DNSP draft decision*, p. 197, footnote 549.

The NSPs disputed the draft decision on direct equity raising costs but did not present an alternative unit cost in their revised regulatory proposals.[1677] 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.[1678] CEG decomposed the 7.6 per cent unit cost in its May 2008 report:[1679]

> 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.[1680] 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.

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.[1681]

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 the Office of Gas and Electricity Markets (the UK regulator (Ofgem)) precedent should lead to an allowance of 5 per cent for direct equity raising costs,[1682] since this was the final unit cost approved by Ofgem in its 2006 price control review.[1683]

[1677] TransGrid, *Revised revenue proposal*, pp. 79–82; EnergyAustralia, *Revised regulatory proposal*, pp. 44–47.

[1678] TransGrid, *Revised revenue proposal*, p. 82; EnergyAustralia, *Revised regulatory proposal*, p. 49.

[1679] CEG; May 2008 (TransGrid), p. 25, paragraph 84; CEG, April 2008 (Integral Energy), p. 25, paragraph 85; CEG, November 2008 (JIA), p. 27, paragraph 96.

[1680] 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.

[1681] Handley, April 2009, p. 26.

[1682] CEG, *Memorandum*, February 2009, p. 2.

[1683] OFGEM, *Transmission price control review: Final proposals*, 4 December 2006.

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.[1684] 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.

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 benchmarks in the PTRM.[1685] The issues identified by the NSPs and their consultants included:[1686]

- 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:[1687]

> 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

[1684] 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.

[1685] 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.

[1686] For example, TransGrid, *Revised revenue proposal*, pp 80–81; EnergyAustralia, *Revised regulatory proposal*, pp. 47–48.

[1687] Integral Energy, *Submission,* 16 February 2009, p. 10.

> 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).[1688] However, as the AER has applied a benchmark approach to determining the appropriate allowance for equity raising costs,[1689] it agrees with Associate Professor Handley that assumptions should be consistent with the overall regulatory framework.[1690]

The NSPs noted that the effective dividend yield assumed in the draft decision was less than 3 per cent.[1691] 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.[1692] TransGrid also stated that equity holders expect to receive their return on equity as dividends.[1693] 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:[1694]

> 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.[1695] TransGrid and EnergyAustralia did not apply the recommendations of the report by

[1688] 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.

[1689] 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.

[1690] Handley, April 2009, pp. 30–33.

[1691] TransGrid, *Revised revenue proposal*, p. 81; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46.

[1692] TransGrid, *Revised revenue proposal*, p. 81; EnergyAustralia, *Revised regulatory proposal*, p. 48; Integral Energy, *Revised regulatory proposal*, p. 46.

[1693] TransGrid, *Revised revenue proposal*, p. 81.

[1694] CEG, January 2009, p. 28.

[1695] Carlton, January 2009 (EnergyAustralia), pp. 27–29, section 3.2.

Carlton, but suggested that there is merit in further review of his recommended approach.[1696]

Integral Energy submitted that the inconsistency between the PTRM and the benchmark equity raising cash flow analysis was attributable to different measures of depreciation:[1697]

> 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.

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.[1698] 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.[1699] 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.[1700]

1696 TransGrid, *Revised revenue proposal*, p. 82.

1697 Integral Energy, *Submission*, 16 February 2009, Attachment 3, p. 3.

1698 NER, clause 6A.5.3.

1699 Carlton, January 2009 (EnergyAustralia), p. 26. See also KPMG, January 2009, pp. 10–11.

1700 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

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.[1701] In the draft decision, the 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.[1702]

This observation was made in the ACCC's TransGrid 2004 draft decision,[1703] which informed its view that the assumed utilisation of imputation credits be 0.5 in the 2004 Statement of Regulatory Principles (SRP).[1704] 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.[1705] The decision also cited an average dividend payout ratio of approximately 70 per cent before concluding that the gamma value should be 0.5.[1706] 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.[1707] One of the key assumptions supporting the AER's proposed position on gamma was an imputation credit payout ratio of 100 per

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.

1701 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 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.

1702 AER, *NSW DNSP draft decision*, p. 195, footnote 547.

1703 ACCC, *NSW and ACT Transmission Network Revenue Caps– TransGrid 2004/05–2008/09: Draft decision*, 28 April 2004, pp. 87–88.

1704 ACCC, *Statement of principles for the regulation of electricity transmission revenues: Decision*, 8 December 2004, p. 17, point 8.9.

1705 ACCC, *TransGrid draft decision*, April 2004, p. 87.

1706 ACCC, *TransGrid draft decision*, April 2004, p. 87, footnote 54.

1707 AER, *WACC review: Explanatory statement*, 12 December 2008, pp. 13–14.

cent, following the recommendation of the AER's consultant, Associate Professor Handley. In his report Associate Professor Handley argued that:[1708]

> …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.[1709] However, Carlton suggested that the payout assumption is required to be 100 per cent citing the AER's WACC explanatory statement that indicates an assumption that 100 per cent of imputation credits are paid out.[1710] A similar view was put forward by SFG and KPMG.[1711]

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.[1712] 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

[1708] Handley, J.C., *A note on the valuation of imputation credits*, 12 November 2008, p. 4.
[1709] The product of ~0.7 (payout ratio) and ~0.7 (utilisation) is 0.5, consistent with the required gamma value specified in the NER.
[1710] Carlton, January 2009 (EnergyAustralia), p. 26; Carlton, January 2009 (TransGrid), pp. 5–6.
[1711] SFG, March 2009, pp. 14–15, paragraphs 58–61; KPMG, January 2009, p. 2.
[1712] Carlton, January 2009 (EnergyAustralia), pp. 23–26, section 3.1.

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.[1713] 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:

$$\text{Dividends} = \left(\frac{\text{Imputation credits earned}}{\text{tax rate}} \right) \times \left(1 - \text{tax rate}\right) \times \text{payout ratio}$$

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).[1714] 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[1715] 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,[1716] as discussed above, the AER considers that an allowance for such costs would be inappropriate. This view is supported by Associate Professor Handley.[1717]

[1713] 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.
[1714] For the amounts to precisely equate, the assumed utilisation of imputation credits by shareholders is calculated to be 71 per cent.
[1715] ACG suggested that the cost of raising equity through a DRP should be zero. ACG, 2004, p. 63.
[1716] Carlton, January 2009 (EnergyAustralia), pp. 29–30; Carlton, January 2009 (TransGrid), pp. 35–36.
[1717] Handley, April 2009, pp. 23–24.

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.[1718] Carlton stated that anecdotal evidence suggests that underwriting fees of around 2.5 per cent are being charged for DRP underwriting.[1719] 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.[1720]

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 capital raised which, in turn, implies that the underwriting cost as a percentage of equity raised is about half of 2.5 per cent.[1721]

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.[1722] 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.[1723] However, the ACG and Carlton support an estimate of 30 per cent reinvestment of dividends.[1724] 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.[1725] The AER analysed data for Australian energy network businesses and found that about 30 per cent of dividends distributed were returned through a DRP.[1726]

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.[1727] However, the AER

[1718] ACG, 2004, p. 63.
[1719] Carlton, January 2009 (EnergyAustralia), pp. 29–30; Carlton, January 2009 (TransGrid), p. 36.
[1720] Handley, April 2009, pp. 26–27.
[1721] 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.
[1722] AER assessment of Bloomberg data and annual reports.
[1723] Handley, April 2009, pp. 23 and 26.
[1724] Carlton, January 2009 (TransGrid), p.36; ACG, 2004, p. 63.
[1725] Carlton, January 2009 (TransGrid), pp. 48–49.
[1726] AER assessment of data sourced from Bloomberg.
[1727] 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.

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.

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.[1728]

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.[1729] 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

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[1728] 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.

[1729] 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.

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',[1730] rather than being calculated as 60 per cent of capex. The residual of capex less the increase in debt funding is the amount of capex that must be funded through retained earnings and then new equity.[1731]

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.

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.[1732] 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

[1730] The repayment of debt is multiplied by minus 1 in order to express the debt component of capex as a positive number.

[1731] 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).

[1732] 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.

- it implements the recommendation made by ACG in its 2004 report.[1733]

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 the relevant RAB for the purpose of providing the equity raising cost allowance associated with forecast capex for the next regulatory control period.

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

[1733] ACG, 2004, p. xiii.

two allowances will then be added to the RAB, and amortised over the weighted average standard life of the RAB.

Appendix O: 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.[1734]

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.[1735] 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.[1736]

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 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.

1734 The arguments put forward and consultant reports referred to by each NSP are set out in the cost of capital chapter.

1735 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.

1736 CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 4.

O.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:[1737]

> 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.

O.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.[1738] 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.[1739] Further, it noted that in the current global financial crisis returns from holding government bonds have had a negative relationship with returns from holding equity.[1740]

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

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[1737] Officer R.R., p. 6.

[1738] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 7–12.

[1739] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 29.

[1740] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 11.

estimate of the required return on equity when combined with other input parameters.[1741] 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.[1742]

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.[1743]

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.

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

[1741] SFG Consulting, *Review of TransGrid approach to WACC averaging period*, 14 February 2009, pp. 17–18.
[1742] Grundy, 16 February 2009, pp. 3–4.
[1743] SFG Consulting, p. 23.

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.

O.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.[1744]

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 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 to 2005 and 8.2 per cent over

[1744] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 64.

1958 to 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.[1745]

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.[1746]

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.

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.[1747] 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.[1748]

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

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[1745] Tim Brailsford, John C Handley, Krishnan Maheswaran, *Re-examination of the historical equity risk premium in Australia*, Accounting and Finance 48 (2008), pp. 73–97.

[1746] EnergyAustralia, *Further submission on the AER's draft decision*, p. 9.

[1747] Grundy, pp. 10–11.

[1748] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 36–39.

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.[1749] 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.

O.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.[1750]

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.[1751]

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 (section 11.5.3). This issue was 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.

[1749] 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.

[1750] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 40–46.

[1751] CEG, *Rate of return and the averaging period under the National Electricity Rules and Law*, January 2009, p. 42.

O.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.[1752]

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.[1753]

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 average business lending costs on outstanding loans have declined by around 230 basis points since the start of the monetary policy easing cycle.[1754]

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

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[1752] CEG, Rate *of return and the averaging period under the National Electricity Rules and Law*, January 2009, pp. 18–21.

[1753] Grundy, p. 4.

[1754] RBA, *Statement on monetary policy*, February 2009. Available: http://www.rba.gov.au/PublicationsAndResearch/StatementsOnMonetaryPolicy/Feb2009/domestic_financial_markets.html, viewed 13 February 2009.

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 11.5.2 of this final decision.

O.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.[1755] CEG reiterated the need for business certainty in its January 2009 report.

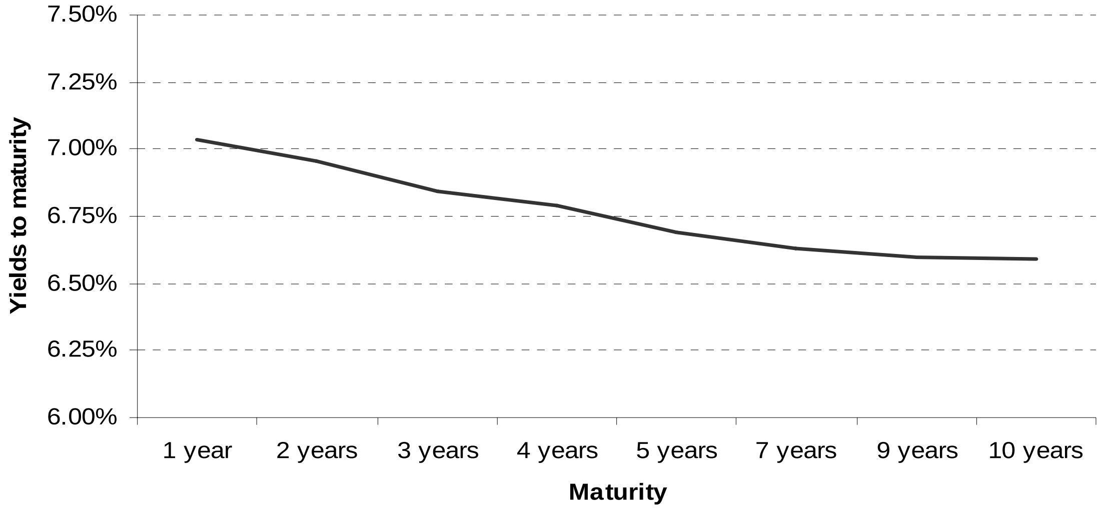
The AER does not agree that the main consideration for setting the WACC parameters was to provide the NSPs early rate of return certainty as interpreted by CEG. The AEMC's aim was to provide short–term stability regarding the WACC determination by reducing an important source of potential differences between regulatory decisions.[1756] 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 O.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 O.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 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.

[1755] 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 under the National Electricity Rules and Law*, January 2009, p. 27.

[1756] AEMC, *Rule determination*, Rule No 2006 No. 18, p. 82.

Figure O.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.[1757]

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.[1758] 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.

O.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:

[1757] EnergyAustralia, *Revised regulatory proposal*, attachment 8A, p. 4.
[1758] Powerlink, letter to the AER – risk–free rate — confidential, 7 December 2005.

- The approach is consistent with recent transmission determinations made under chapter 6A of the NER for ElectraNet and SP AusNet.[1759]
- 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.[1760]
- The AEMC's transmission rule (noted above) was adopted by the Standing Committee of Officials of the Ministerial Council on Energy for the WACC in the transitional chapter 6 rules.[1761]
- The AER's approach was recently enunciated in its WACC review issues paper released in August 2008.[1762] 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).[1763]

- 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.[1764]

- JIA also submitted that the regulated businesses should have the discretion to select the start date and noted that continuing the current practice:
  - 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

[1759] 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.

[1760] 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.

[1761] 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

[1762] AER, *Issues paper, Review of the WACC parameters for electricity transmission and distribution*, August 2008.

[1763] AER, *Issues paper, Review of the WACC parameters,* p. 36.

[1764] JIA, *Network Industry Submission, AER issues paper–Review of the WACC parameters for electricity transmission and distribution*, September 2008, pp. 76–77.

    - 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.[1765]

- 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.[1766] This formalisation of the current approach was not objected to by JIA in its submissions on the WACC review draft decision.

O.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.[1767]

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.[1768]

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 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

[1765] JIA, pp. 76–77.
[1766] AER, *Explanatory statement, Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters*, December 2008, p. 133.
[1767] NEL, clause 7A(2).
[1768] EnergyAustralia, *Revised regulatory proposal*, p. 58.

inconsistent with the revenue and pricing principles in the NEL that require incentives to promote economic efficiency.[1769]

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.[1770]

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.[1771] 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.[1772] For TransGrid's/EnergyAustralia's (transmission) and Transend's current regulatory control period the ACCC determined a nominal vanilla WACC of 9.08 and 8.80 per cent respectively and these compare with a nominal vanilla WACC of 8.79 per cent and 8.80 per cent for the next regulatory control period.[1773] 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.[1774] 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 control period.[1775]

Overall, the AER considers that the NSPs are not being deprived of a reasonable opportunity to recover their efficient cost of capital.

O.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

[1769] NEL, clause 7A(3).

[1770] 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.

[1771] 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.

[1772] This varies depending on the effective tax rate modelled for each NSP.

[1773] 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.

[1774] RBA, Cash rate target, viewed 23 March 2009. Available: <http://www.rba.gov.au/Statistics/cashrate_target.html>

[1775] On 7 April 2009 the RBA further reduced the cash rate to 3.0 per cent.

that its agreed averaging periods are consistent with finance theory, regulatory practice, the NER and NEL.

Appendix P: Total customer bill and price path (confidential)

Appendix Q: 2008–09 and 2009–10 total customer bill comparison

Country Energy

Customer bills ($ p.a)	% Change from current 2008-09 to AER revised 2009-10
ARMIDALE DUMARESQ COUNCIL	–41
BALLINA SHIRE COUNCIL	–39
BALONNE SHIRE COUNCIL	–34
BALRANALD SHIRE COUNCIL	–4
BATHURST REGIONAL COUNCIL	–11
BEGA VALLEY SHIRE COUNCIL	–35
BELLINGEN SHIRE COUNCIL	–37
BERRIGAN SHIRE COUNCIL	–42
BLAND SHIRE COUNCIL	–37
BLAYNEY SHIRE COUNCIL	–36
BOGAN SHIRE COUNCIL	–33
BOMBALA SHIRE COUNCIL	–41
BOOROWA COUNCIL	–40
BOURKE SHIRE COUNCIL	–31
BREWARRINA SHIRE COUNCIL	–52
BROKEN HILL CITY COUNCIL	–45
BYRON SHIRE COUNCIL	–33
CABONNE SHIRE COUNCIL	–36
CARRATHOOL SHIRE COUNCIL	–40
CENTRAL DARLING SHIRE COUNCIL	–45
CITY OF ALBURY	–41
CITY OF WAGGA WAGGA	–42
CLARENCE VALLEY COUNCIL	–37
COBAR SHIRE COUNCIL	–25
COFFS HARBOUR CITY COUNCIL	–24
CONARGO SHIRE COUNCIL	–40
COOLAMON SHIRE COUNCIL	–41
COOMA-MONARO COUNCIL	–39
COONAMBLE SHIRE COUNCIL	–33
COOTAMUNDRA SHIRE COUNCIL	–39
COROWA SHIRE COUNCIL	–42
COWRA SHIRE COUNCIL	–30
DENILIQUIN MUNICIPAL COUNCIL	–40
DEPARTMENT OF TRANSPORT QLD	13
DEPT OF LAND AND WATER CONSERV.	–40
DUBBO CITY COUNCIL	–31
DUNGOG SHIRE COUNCIL	–6
EAST GIPPSLAND SHIRE COUNCIL	–29
EUROBODALLA SHIRE	–39
FORBES SHIRE COUNCIL	–25

GILGANDRA SHIRE COUNCIL	–27
GLEN INNES SEVERN SHIRE COUNCIL	–25
GLOUCESTER SHIRE COUNCIL	–10
GOONDIWINDI SHIRE COUNCIL	–25
GOULBURN MULWAREE COUNCIL	–41
GREAT LAKES	7
GREATER HUME SHIRE COUNCIL	–37
GREATER TAREE	3
GRIFFITH CITY COUNCIL	–42
GUNDAGAI SHIRE COUNCIL	–41
GUNNEDAH SHIRE COUNCIL	–26
GUYRA SHIRE COUNCIL	–24
GWYDIR SHIRE COUNCIL	–33
HARDEN SHIRE COUNCIL	–7
HASTINGS COUNCIL	2
HAY SHIRE COUNCIL	–40
INGLEWOOD SHIRE COUNCIL	–41
INVERELL SHIRE COUNCIL	–33
JERILDERIE SHIRE COUNCIL	–47
JUNEE SHIRE COUNCIL	–37
KEMPSEY SHIRE COUNCIL	–13
KYOGLE SHIRE COUNCIL	–37
LACHLAN SHIRE COUNCIL	–30
LEETON SHIRE COUNCIL	–44
LISMORE CITY COUNCIL	–33
LIVERPOOL PLAINS SHIRE COUNCIL	–13
LOCKHART SHIRE COUNCIL	–32
MID-WESTERN REGIONAL COUNCIL	–42
MOREE PLAINS SHIRE COUNCIL	–27
MURRAY SHIRE COUNCIL	–40
MURRUMBIDGEE SHIRE COUNCIL	–40
NAMBUCCA SHIRE COUNCIL	–39
NARRABRI SHIRE COUNCIL	–36
NARRANDERA SHIRE COUNCIL	–40
NARROMINE SHIRE COUNCIL	–32
OBERON COUNCIL	–25
ORANGE CITY COUNCIL	–34
PALARANG COUNCIL	–41
PARKES SHIRE COUNCIL	–21
QUEANBEYAN CITY COUNCIL	–43
RICHMOND VALLEY COUNCIL	–34
ROADS AND TRAFFIC AUTHORITY	–47
ROADS AND TRAFFIC AUTHORITY(COLONGOLOOK)	–52
SHOALHAVEN CITY COUNCIL	–41
SNOWY RIVER SHIRE COUNCIL	–41
STANTHORPE SHIRE COUNCIL	–34
STATE RAIL AUTHORITY	–47
TAMWORTH REGIONAL COUNCIL	–12
TEMORA SHIRE COUNCIL	–44
TENTERFIELD SHIRE COUNCIL	–41
TUMBARUMBA SHIRE COUNCIL	–38
TUMUT SHIRE COUNCIL	–40

TWEED SHIRE COUNCIL	–39
UPPER HUNTER SHIRE COUNCIL	–23
UPPER LACHLAN COUNCIL	–40
URALLA SHIRE COUNCIL	–42
URANA SHIRE COUNCIL	–39
WAGGAMBA SHIRE COUNCIL	–37
WAKOOL SHIRE COUNCIL	–39
WALCHA SHIRE COUNCIL	–42
WALGETT SHIRE COUNCIL	–31
WARREN SHIRE COUNCIL	–26
WARRUMBUNGLE SHIRE COUNCIL	–39
WEDDIN SHIRE COUNCIL	–26
WELLINGTON SHIRE COUNCIL	–41
WENTWORTH SHIRE COUNCIL	–24
YASS VALLEY COUNCIL	–40
YOUNG SHIRE COUNCIL	–40
Average	–33

EnergyAustralia

Customer bills ($ p.a)	% Change from current 2008-09 to AER revised 2009-10
ASHFIELD MUNICIPAL CNCL	–15
AUBURN BAPTIST CHURCH	–4
AUBURN MUNICIPAL COUNCIL	–20
AVONDALE GOLF CLUB	–
BANKSTOWN CITY COUNCIL	–21
BANKSTOWN TROTTING & REC CL	–13
BAULKHAM HILLS CNCIL	–21
BOTANY MUNICIPAL COUNCIL	–18
BURWOOD MNCPL COUNCIL	–14
CANTERBURY MNCPL COUNCIL	–16
CENTENNIAL PARK & MOORE PAR	–25
CESSNOCK CITY COUNCIL	–4
CITYWEST DEVELOPMENT CORPN	–28
COM ASSN 23-29 SHEP.DR CHRY	–28
COMMUNITY ASSN @ TILLEY LN	–29
COMMUNITY ASSN DP270051	–24
COMMUNITY ASSN DP270082	–26
COMMUNITY ASSN DP270223	–21
COMMUNITY ASSN DP270297	–21
COMMUNITY ASSOC CP270144	–17
COMMUNITY ASSOCIATION DP270	–22
CONCORD MNCPL COUNCIL	–12
DARLING HARBOUR AUTHORITY	–27
DEFENCE ENERGY SERVICES	220
DEPT OF EDUCATION/FORT ST H	–17
DEPT OF TRANSPORT	–41
DRUMMOYNE MUNICIPAL COUNCIL	–11
ENERGYAUSTRALIA	–19
GOSFORD CITY COUNCIL 860	–10
HEZ NOMINEES PTY LTD	–37
HORNSBY SHIRE COUNCIL	–22
HOUSING COMMISSION NSW	–
HUNTERS HILL MNCPL COUNCIL	–21
HURSTVILLE CITY COUNCIL	–15
INTERLINK ROAD	–
KOGARAH MUNICIPAL COUNCIL	–14
KU-RING-GAI MUNCPL CNCL	–19
LAKE MACQUARIE CITY COUNCIL	–10
LANE COVE MUNCPL COUNCIL	–16
LEICHHARDT MNCPL COUNCIL	–18
M S B - HORNSBY	–
M S B - PORT OF SYDNEY	–29
MAITLAND CITY COUNCIL	–18
MANLY MUNICIPAL COUNCIL 850	–8
MARRICKVILLE MUNCPL COUNCIL	–10

MIRVAC LEND LEASE VILLAGE C	–21
MONA VALE HOSPITAL	–
MOSMAN MUNICIPAL COUNCIL 83	–25
MUSWELLBROOK SHIRE COUNCIL	–19
N/HOOD ASSN DP 285088	–19
NEIGHBOURHOOD ASSN DP270207	–15
NEIGHBOURHOOD ASSN DP270217	–16
NEIGHBOURHOOD ASSN DP276638	–18
NEIGHBOURHOOD ASSN DP285067	–23
NEIGHBOURHOOD ASSN DP285096	–18
NEIGHBOURHOOD ASSN DP285097	–24
NEIGHBOURHOOD ASSN DP285177	–19
NEIGHBOURHOOD ASSN DP285203	–13
NEIGHBOURHOOD ASSN DP285210	–19
NEIGHBOURHOOD ASSN DP285657	–5
NEIGHBOURHOOD ASSN DP285696	–20
NEIGHBOURHOOD ASSN DP815457	–16
NEIGHBOURHOOD ASSN DP840807	–18
NEIGHBOURHOOD ASSOC.D/P 285	–16
NEWCASTLE CITY COUNCIL	–15
N'HOOD ASSNS DP270038/28517	–23
NORTH SYDNEY MNCPL CNCL	–18
NSW MARITIME	–31
OWNERS CORPORATION DP 27037	–26
PADSTOW BOWLING & RECREATIO	–14
PARRAMATTA CITY COUNCIL	–11
PITTWATER MUNICIPAL COUNCIL	–2
PITTWATER RSL CLUB	–10
PORT STEPHENS SHIRE COUNCIL	–15
PRESBYTERIAN CH OF AUST	143
R J CAINS	–
RANDWICK CITY COUNCIL	–17
ROADS & TRAFFIC AUTHORITY 0	–26
ROCKDALE MUNICIPAL COUNCIL	–15
ROSELANDS BOWLING CLUB	–15
ROYAL NORTH SHORE HOSPITAL	–22
ROYAL PRINCE ALFRED HOSPITA	–11
ROYAL RYDE HOMES	108
RYDE HOSPITAL	96
RYDE MUNICIPAL COUNCIL	–20
SINGLETON SHIRE COUNCIL	–19
STATE RAIL AUTHORITY - SOUT	–8
STATE RAIL AUTHORITY-C COAS	–14
STATE RAIL AUTHORITY-NORTH	–28
STATE TRANSIT AUTHORITY	–18
STRATHFIELD MUNICIPAL COUNC	–15
SUTHERLAND SHIRE CNCL	–19
SYDNEY CITY COUNCIL 411	–20
SYDNEY COVE DEV AUTH	–
UPPER HUNTER SHIRE COUNCIL	–11
WARRINGAH SHIRE COUNCIL 851	–7
WAVERLEY MUNICIPAL COUNCIL	–22

WILLOUGHBY CITY COUNCIL	–14
WOOLLAHRA MUNICIPAL COUNCIL	–23
WYONG SHIRE COUNCIL 861	–11
ZOOLOGICAL PARKS BOARD OF N	–12
Average	–11

Integral Energy

Customer bills ($ p.a)	% Change from current 2008-09 to AER revised 2009-10
BANKSTOWN CITY COUNCIL	–47
BAULKHAM HILLS SHIRE COUNCIL	13
BLACKTOWN CITY COUNCIL	2
BLUE MOUNTAINS CITY COUNCIL	–12
CAMPBELLTOWN CITY COUNCIL	–5
COUNCIL OF THE CITY OF SHELLHARBOUR	–5
EVANS SHIRE COUNCIL	34
FAIRFIELD CITY COUNCIL	–13
HAWKESBURY CITY COUNCIL	–13
HMAS ALBATROSS	–25
HOLROYD CITY COUNCIL	–19
HORNSBY SHIRE COUNCIL	–27
KIAMA MUNICIPAL COUNCIL	–14
LITHGOW CITY COUNCIL	–7
LIVERPOOL CITY COUNCIL	3
MID WESTERN REGIONAL COUNCIL	–23
NSW MARITIME AUTHORITY	–43
PARRAMATTA CITY COUNCIL	–19
PENRITH CITY COUNCIL	–2
PORT KEMBLA PORT CORPORATION	52
ROADS & TRAFFIC AUTHORITY	40
RYDE CITY COUNCIL	–35
SHOALHAVEN CITY COUNCIL	–10
SYDNEY CATCHMENT AUTHORITY	–29
THE COUNCIL OF CAMDEN	16
THE DEPARTMENT OF LANDS	35
WINGECARRIBEE SHIRE COUNCIL	–8
WOLLONDILLY SHIRE COUNCIL	–7
WOLLONGONG CITY COUNCIL	–14
Average	–6

Appendix R: Tariffs 3 and 4

Country Energy

Tariff class	Tariff description	Description	Dedicated pole	Number of lights	Country Energy proposed	AER final	% Change
					Jan-09	Apr–09	
3	FLU0350-ST-1620-003-B	Compact Fluorescent 1x42	SHARED OR NO POLE	1	155.35	95.87	–38
3	FLU0350-ST-1620-003-S	Compact Fluorescent 1x42	SHARED OR NO POLE	1	149.65	113.64	–24
3	FLU0350-ST-1630-003-B	Compact Fluorescent 1x42	SHARED OR NO POLE	2	189.66	121.86	–36
3	FLU0350-ST-1630-003-S	Compact Fluorescent 1x42	SHARED OR NO POLE	2	183.95	139.63	–24
3	FLU0350-ST-1640-003-B	Compact Fluorescent 1x42	SHARED OR NO POLE	3	223.97	147.85	–34
3	FLU0350-ST-1640-003-S	Compact Fluorescent 1x42	SHARED OR NO POLE	3	218.26	165.63	–24
3	FLU0350-ST-1650-003-B	Compact Fluorescent 1x42	SHARED OR NO POLE	4	258.28	173.84	–33
3	FLU0350-ST-1650-003-S	Compact Fluorescent 1x42	SHARED OR NO POLE	4	252.57	191.62	–24
3	FLU0350-ST-1660-003-B	Compact Fluorescent 1x42	WOOD POLE	1	313.79	213.34	–32
3	FLU0350-ST-1660-003-S	Compact Fluorescent 1x42	WOOD POLE	1	308.08	231.11	–25
3	FLU0350-ST-1670-003-B	Compact Fluorescent 1x42	WOOD POLE	2	348.1	239.33	–31
3	FLU0350-ST-1670-003-S	Compact Fluorescent 1x42	WOOD POLE	2	342.39	257.10	–25
3	FLU0350-ST-1680-003-B	Compact Fluorescent 1x42	WOOD POLE	3	382.4	265.32	–31
3	FLU0350-ST-1680-003-S	Compact Fluorescent 1x42	WOOD POLE	3	376.7	283.10	–25
3	FLU0350-ST-1690-003-B	Compact Fluorescent 1x42	WOOD POLE	4	416.71	291.31	–30
3	FLU0350-ST-1690-003-S	Compact Fluorescent 1x42	WOOD POLE	4	411.01	309.09	–25
3	FLU0350-ST-1700-003-B	Compact Fluorescent 1x42	STEEL POLE	1	430.98	299.40	–31
3	FLU0350-ST-1700-003-S	Compact Fluorescent 1x42	STEEL POLE	1	425.27	317.18	–25
3	FLU0350-ST-1710-003-B	Compact Fluorescent 1x42	STEEL POLE	2	465.29	325.40	–30
3	FLU0350-ST-1710-003-S	Compact Fluorescent 1x42	STEEL POLE	2	459.58	343.17	–25
3	FLU0350-ST-1720-003-B	Compact Fluorescent 1x42	STEEL POLE	3	499.6	351.39	–30

3	FLU0350-ST-1720-003-S	Compact Fluorescent 1x42	STEEL POLE	3	493.89	369.16	–25
3	FLU0350-ST-1730-003-B	Compact Fluorescent 1x42	STEEL POLE	4	533.91	377.38	–29
3	FLU0350-ST-1730-003-S	Compact Fluorescent 1x42	STEEL POLE	4	528.2	395.16	–25
3	FLU0360-ST-1740-003-B	T5 2x14W	SHARED OR NO POLE	1	173.87	108.41	–38
3	FLU0360-ST-1740-003-S	T5 2x14W	SHARED OR NO POLE	1	164.09	123.99	–24
3	FLU0360-ST-1750-003-B	T5 2x14W	SHARED OR NO POLE	2	224.85	146.58	–35
3	FLU0360-ST-1750-003-S	T5 2x14W	SHARED OR NO POLE	2	215.06	162.16	–25
3	FLU0360-ST-1760-003-B	T5 2x14W	SHARED OR NO POLE	3	275.83	184.75	–33
3	FLU0360-ST-1760-003-S	T5 2x14W	SHARED OR NO POLE	3	266.04	200.34	–25
3	FLU0360-ST-1770-003-B	T5 2x14W	SHARED OR NO POLE	4	326.8	222.93	–32
3	FLU0360-ST-1770-003-S	T5 2x14W	SHARED OR NO POLE	4	317.02	238.51	–25
3	FLU0360-ST-1780-003-B	T5 2x14W	WOOD POLE	1	332.31	225.88	–32
3	FLU0360-ST-1780-003-S	T5 2x14W	WOOD POLE	1	322.52	241.46	–25
3	FLU0360-ST-1790-003-B	T5 2x14W	WOOD POLE	2	383.29	264.05	–31
3	FLU0360-ST-1790-003-S	T5 2x14W	WOOD POLE	2	373.5	279.63	–25
3	FLU0360-ST-1800-003-B	T5 2x14W	WOOD POLE	3	434.26	302.22	–30
3	FLU0360-ST-1800-003-S	T5 2x14W	WOOD POLE	3	424.48	317.81	–25
3	FLU0360-ST-1810-003-B	T5 2x14W	WOOD POLE	4	485.24	340.40	–30
3	FLU0360-ST-1810-003-S	T5 2x14W	WOOD POLE	4	475.45	355.98	–25
3	FLU0360-ST-1820-003-B	T5 2x14W	STEEL POLE	1	449.5	311.95	–31
3	FLU0360-ST-1820-003-S	T5 2x14W	STEEL POLE	1	439.72	327.53	–26
3	FLU0360-ST-1830-003-B	T5 2x14W	STEEL POLE	2	500.48	350.12	–30
3	FLU0360-ST-1830-003-S	T5 2x14W	STEEL POLE	2	490.69	365.70	–25
3	FLU0360-ST-1840-003-B	T5 2x14W	STEEL POLE	3	551.45	388.29	–30
3	FLU0360-ST-1840-003-S	T5 2x14W	STEEL POLE	3	541.67	403.87	–25
3	FLU0360-ST-1850-003-B	T5 2x14W	STEEL POLE	4	602.43	426.46	–29
3	FLU0360-ST-1850-003-S	T5 2x14W	STEEL POLE	4	592.65	442.05	–25
3	FLU0370-ST-1860-003-B	T5 2x24W	SHARED OR NO POLE	1	190.29	119.87	–37
3	FLU0370-ST-1860-003-S	T5 2x24W	SHARED OR NO POLE	1	177.21	134.22	–24
3	FLU0370-ST-1870-003-B	T5 2x24W	SHARED OR NO POLE	2	247.48	162.58	–34
3	FLU0370-ST-1870-003-S	T5 2x24W	SHARED OR NO POLE	2	234.4	176.93	–25

3	FLU0370-ST-1880-003-B	T5 2x24W	SHARED OR NO POLE	3	304.67	205.30	–33
3	FLU0370-ST-1880-003-S	T5 2x24W	SHARED OR NO POLE	3	291.59	219.64	–25
3	FLU0370-ST-1890-003-B	T5 2x24W	SHARED OR NO POLE	4	361.86	248.01	–31
3	FLU0370-ST-1890-003-S	T5 2x24W	SHARED OR NO POLE	4	348.78	262.36	–25
3	FLU0370-ST-1910-003-B	T5 2x24W	WOOD POLE	2	405.91	280.05	–31
3	FLU0370-ST-1910-003-S	T5 2x24W	WOOD POLE	2	392.84	294.40	–25
3	FLU0370-ST-1920-003-B	T5 2x24W	WOOD POLE	3	463.1	322.77	–30
3	FLU0370-ST-1920-003-S	T5 2x24W	WOOD POLE	3	450.03	337.11	–25
3	FLU0370-ST-1930-003-B	T5 2x24W	WOOD POLE	4	520.29	365.48	–30
3	FLU0370-ST-1930-003-S	T5 2x24W	WOOD POLE	4	507.22	379.83	–25
3	FLU0370-ST-1940-003-B	T5 2x24W	STEEL POLE	1	465.92	323.41	–31
3	FLU0370-ST-1940-003-S	T5 2x24W	STEEL POLE	1	452.84	337.75	–25
3	FLU0370-ST-1950-003-B	T5 2x24W	STEEL POLE	2	523.11	366.12	–30
3	FLU0370-ST-1950-003-S	T5 2x24W	STEEL POLE	2	510.03	380.47	–25
3	FLU0370-ST-1960-003-B	T5 2x24W	STEEL POLE	3	580.3	408.83	–30
3	FLU0370-ST-1960-003-S	T5 2x24W	STEEL POLE	3	567.22	423.18	–25
3	FLU0370-ST-1970-003-B	T5 2x24W	STEEL POLE	4	637.49	451.55	–29
3	FLU0370-ST-1970-003-S	T5 2x24W	STEEL POLE	4	624.41	465.89	–25
3	HPS0020-ST-0040-003-B	High Pressure Sodium 70	SHARED OR NO POLE	1	142.77	92.90	–35
3	HPS0020-ST-0040-003-S	High Pressure Sodium 70	SHARED OR NO POLE	1	138.8	103.54	–25
3	HPS0020-ST-0350-003-B	High Pressure Sodium 70	WOOD POLE	1	301.2	210.37	–30
3	HPS0020-ST-0350-003-S	High Pressure Sodium 70	WOOD POLE	1	297.23	221.01	–26
3	HPS0020-ST-0360-003-B	High Pressure Sodium 70	STEEL POLE	1	418.4	296.44	–29
3	HPS0020-ST-0360-003-S	High Pressure Sodium 70	STEEL POLE	1	414.42	307.08	–26
3	HPS0020-ST-0730-003-B	High Pressure Sodium 70	STEEL POLE	2	449.64	320.19	–29
3	HPS0020-ST-0730-003-S	High Pressure Sodium 70	STEEL POLE	2	445.67	330.83	–26
3	HPS0020-ST-0890-003-B	High Pressure Sodium 70	SHARED OR NO POLE	2	174.01	116.66	–33
3	HPS0020-ST-0890-003-S	High Pressure Sodium 70	SHARED OR NO POLE	2	170.04	127.29	–25
3	HPS0020-ST-0910-003-B	High Pressure Sodium 70	WOOD POLE	2	332.45	234.13	–30
3	HPS0020-ST-0910-003-S	High Pressure Sodium 70	WOOD POLE	2	328.48	244.76	–25
3	HPS0020-TA-0090-003-B	High Pressure Sodium 70	SHARED OR NO POLE	1	139.44	93.97	–33

3	HPS0020-TA-0090-003-S	High Pressure Sodium 70	SHARED OR NO POLE	1	137.09	100.39	–27
3	HPS0020-TA-0140-003-B	High Pressure Sodium 70	WOOD POLE	1	297.88	211.44	–29
3	HPS0020-TA-0140-003-S	High Pressure Sodium 70	WOOD POLE	1	295.53	217.86	–26
3	HPS0020-TA-0170-003-B	High Pressure Sodium 70	STEEL POLE	1	415.07	297.51	–28
3	HPS0020-TA-0170-003-S	High Pressure Sodium 70	STEEL POLE	1	412.72	303.92	–26
3	HPS0090-ST-0050-003-B	High Pressure Sodium 150	SHARED OR NO POLE	1	211.75	131.21	–38
3	HPS0090-ST-0050-003-S	High Pressure Sodium 150	SHARED OR NO POLE	1	201.46	145.88	–28
3	HPS0090-ST-0220-003-B	High Pressure Sodium 150	WOOD POLE	1	370.19	248.68	–33
3	HPS0090-ST-0220-003-S	High Pressure Sodium 150	WOOD POLE	1	359.9	263.35	–27
3	HPS0090-ST-0310-003-B	High Pressure Sodium 150	STEEL POLE	1	450.64	312.95	–31
3	HPS0090-ST-0310-003-S	High Pressure Sodium 150	STEEL POLE	1	440.35	327.62	–26
3	HPS0090-ST-0690-003-B	High Pressure Sodium 150	STEEL POLE	2	501.52	351.05	–30
3	HPS0090-ST-0690-003-S	High Pressure Sodium 150	STEEL POLE	2	491.23	365.72	–26
3	HPS0090-ST-0720-003-B	High Pressure Sodium 150	STEEL POLE	4	603.3	427.27	–29
3	HPS0090-ST-0720-003-S	High Pressure Sodium 150	STEEL POLE	4	593	441.94	–25
3	HPS0090-ST-1010-003-B	High Pressure Sodium 150	SHARED OR NO POLE	2	262.64	169.32	–36
3	HPS0090-ST-1010-003-S	High Pressure Sodium 150	SHARED OR NO POLE	2	252.35	183.99	–27
3	HPS0090-TA-0050-003-B	High Pressure Sodium 150	SHARED OR NO POLE	1	201.72	134.23	–33
3	HPS0090-TA-0050-003-S	High Pressure Sodium 150	SHARED OR NO POLE	1	192.8	137.01	–29
3	HPS0090-TA-0220-003-B	High Pressure Sodium 150	WOOD POLE	1	360.16	251.70	–30
3	HPS0090-TA-0220-003-S	High Pressure Sodium 150	WOOD POLE	1	351.24	254.48	–28
3	HPS0090-TA-0310-003-B	High Pressure Sodium 150	STEEL POLE	1	440.6	315.97	–28
3	HPS0090-TA-0310-003-S	High Pressure Sodium 150	STEEL POLE	1	431.69	318.75	–26
3	HPS0110-ST-0060-003-B	High Pressure Sodium 250	SHARED OR NO POLE	1	213.69	132.71	–38
3	HPS0110-ST-0060-003-S	High Pressure Sodium 250	SHARED OR NO POLE	1	203.28	147.33	–28
3	HPS0110-ST-0230-003-B	High Pressure Sodium 250	WOOD POLE	1	372.13	250.18	–33
3	HPS0110-ST-0230-003-S	High Pressure Sodium 250	WOOD POLE	1	361.72	264.80	–27
3	HPS0110-ST-0320-003-B	High Pressure Sodium 250	STEEL POLE	1	452.58	314.44	–31
3	HPS0110-ST-0320-003-S	High Pressure Sodium 250	STEEL POLE	1	442.17	329.07	–26
3	HPS0110-ST-0390-003-B	High Pressure Sodium 250	STEEL POLE	2	504	352.94	–30
3	HPS0110-ST-0390-003-S	High Pressure Sodium 250	STEEL POLE	2	493.59	367.56	–26

3	HPS0110-ST-0470-003-B	High Pressure Sodium 250	STEEL POLE	4	606.84	429.94	–29
3	HPS0110-ST-0470-003-S	High Pressure Sodium 250	STEEL POLE	4	596.43	444.56	–25
3	HPS0110-ST-0550-003-B	High Pressure Sodium 250	R/BOUT COLUMN	3	760.18	538.74	–29
3	HPS0110-ST-0550-003-S	High Pressure Sodium 250	R/BOUT COLUMN	3	749.77	553.36	–26
3	HPS0110-ST-0590-003-B	High Pressure Sodium 250	R/BOUT COLUMN	4	811.6	577.24	–29
3	HPS0110-ST-0590-003-S	High Pressure Sodium 250	R/BOUT COLUMN	4	801.19	591.86	–26
3	HPS0110-ST-0610-003-B	High Pressure Sodium 250	SHARED OR NO POLE	1	234.86	148.18	–37
3	HPS0110-ST-0610-003-S	High Pressure Sodium 250	SHARED OR NO POLE	1	224.45	162.80	–27
3	HPS0110-ST-0760-003-B	High Pressure Sodium 250	WOOD POLE	2	423.55	288.68	–32
3	HPS0110-ST-0760-003-S	High Pressure Sodium 250	WOOD POLE	2	413.14	303.30	–27
3	HPS0110-ST-0960-003-B	High Pressure Sodium 250	SHARED OR NO POLE	2	265.11	171.21	–35
3	HPS0110-ST-0960-003-S	High Pressure Sodium 250	SHARED OR NO POLE	2	254.7	185.83	–27
3	HPS0110-ST-1070-003-B	High Pressure Sodium 250	WOOD POLE	1	393.29	265.64	–32
3	HPS0110-ST-1070-003-S	High Pressure Sodium 250	WOOD POLE	1	382.88	280.27	–27
3	HPS0110-ST-1120-003-B	High Pressure Sodium 250	STEEL POLE	1	473.74	329.91	–30
3	HPS0110-ST-1120-003-S	High Pressure Sodium 250	STEEL POLE	1	463.33	344.53	–26
3	HPS0110-ST-1160-003-B	High Pressure Sodium 250	WOOD POLE	2	465.88	319.61	–31
3	HPS0110-ST-1160-003-S	High Pressure Sodium 250	WOOD POLE	2	455.47	334.23	–27
3	HPS0110-TA-0060-003-B	High Pressure Sodium 250	SHARED OR NO POLE	1	197.78	130.83	–34
3	HPS0110-TA-0060-003-S	High Pressure Sodium 250	SHARED OR NO POLE	1	189.78	134.48	–29
3	HPS0110-TA-0230-003-B	High Pressure Sodium 250	WOOD POLE	1	356.22	248.30	–30
3	HPS0110-TA-0230-003-S	High Pressure Sodium 250	WOOD POLE	1	348.21	251.95	–28
3	HPS0110-TA-0320-003-B	High Pressure Sodium 250	STEEL POLE	1	436.67	312.57	–28
3	HPS0110-TA-0320-003-S	High Pressure Sodium 250	STEEL POLE	1	428.66	316.21	–26
3	HPS0110-TA-0470-003-B	High Pressure Sodium 250	STEEL POLE	4	590.93	428.06	–28
3	HPS0110-TA-0470-003-S	High Pressure Sodium 250	STEEL POLE	4	582.93	431.70	–26
3	HPS0110-TA-0590-003-B	High Pressure Sodium 250	R/BOUT COLUMN	4	795.69	575.36	–28
3	HPS0110-TA-0590-003-S	High Pressure Sodium 250	R/BOUT COLUMN	4	787.68	579.00	–26
3	HPS0110-TA-0960-003-B	High Pressure Sodium 250	SHARED OR NO POLE	2	249.2	169.33	–32
3	HPS0110-TA-0960-003-S	High Pressure Sodium 250	SHARED OR NO POLE	2	241.2	172.97	–28
3	HPS0170-ST-0070-003-B	High Pressure Sodium 400	SHARED OR NO POLE	1	234.16	147.48	–37

3	HPS0170-ST-0070-003-S	High Pressure Sodium 400	SHARED OR NO POLE	1	222.14	161.45	–27
3	HPS0170-ST-0240-003-B	High Pressure Sodium 400	WOOD POLE	1	392.6	264.95	–33
3	HPS0170-ST-0240-003-S	High Pressure Sodium 400	WOOD POLE	1	380.57	278.92	–27
3	HPS0170-ST-0330-003-B	High Pressure Sodium 400	STEEL POLE	1	473.05	329.22	–30
3	HPS0170-ST-0330-003-S	High Pressure Sodium 400	STEEL POLE	1	461.02	343.18	–26
3	HPS0170-ST-0400-003-B	High Pressure Sodium 400	STEEL POLE	2	539.67	378.82	–30
3	HPS0170-ST-0400-003-S	High Pressure Sodium 400	STEEL POLE	2	527.64	392.79	–26
3	HPS0170-ST-0440-003-B	High Pressure Sodium 400	STEEL POLE	3	606.29	428.43	–29
3	HPS0170-ST-0440-003-S	High Pressure Sodium 400	STEEL POLE	3	594.26	442.39	–26
3	HPS0170-ST-0620-003-B	High Pressure Sodium 400	SHARED OR NO POLE	1	228.63	143.44	–37
3	HPS0170-ST-0620-003-S	High Pressure Sodium 400	SHARED OR NO POLE	1	216.6	157.40	–27
3	HPS0170-ST-1030-003-B	High Pressure Sodium 400	SHARED OR NO POLE	2	300.78	197.09	–34
3	HPS0170-ST-1030-003-S	High Pressure Sodium 400	SHARED OR NO POLE	2	288.76	211.05	–27
3	HPS0170-ST-1100-003-B	High Pressure Sodium 400	WOOD POLE	1	408.62	276.66	–32
3	HPS0170-ST-1100-003-S	High Pressure Sodium 400	WOOD POLE	1	396.59	290.62	–27
3	HPS0170-ST-1130-003-B	High Pressure Sodium 400	STEEL POLE	2	571.7	402.23	–30
3	HPS0170-ST-1130-003-S	High Pressure Sodium 400	STEEL POLE	2	559.68	416.20	–26
3	HPS0170-ST-1170-003-B	High Pressure Sodium 400	STEEL POLE	1	489.07	340.92	–30
3	HPS0170-ST-1170-003-S	High Pressure Sodium 400	STEEL POLE	1	477.04	354.89	–26
3	HPS0170-ST-1250-003-B	High Pressure Sodium 400	WOOD POLE	3	573.89	399.28	–30
3	HPS0170-ST-1250-003-S	High Pressure Sodium 400	WOOD POLE	3	561.86	413.24	–26
3	HPS0170-TA-0070-003-B	High Pressure Sodium 400	SHARED OR NO POLE	1	221.83	149.22	–33
3	HPS0170-TA-0070-003-S	High Pressure Sodium 400	SHARED OR NO POLE	1	211.44	150.90	–29
3	MHR0060-ST-0320-003-B	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	1	473.62	338.04	–29
3	MHR0060-ST-0320-003-S	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	1	474.91	357.75	–25
3	MHR0060-ST-0610-003-B	Metal Hallide (Reactor Control Gear) 250	SHARED OR NO POLE	1	255.9	171.77	–33
3	MHR0060-ST-0610-003-S	Metal Hallide (Reactor Control Gear) 250	SHARED OR NO POLE	1	257.19	191.48	–26
3	MHR0070-ST-0070-003-B	Metal Hallide (Reactor Control Gear) 400	SHARED OR NO POLE	1	254.38	171.07	–33
3	MHR0070-ST-0070-003-S	Metal Hallide (Reactor Control Gear) 400	SHARED OR NO POLE	1	255.04	190.26	–25
3	MHR0070-ST-0620-003-B	Metal Hallide (Reactor Control Gear) 400	SHARED OR NO POLE	1	248.84	167.02	–33
3	MHR0070-ST-0620-003-S	Metal Hallide (Reactor Control Gear) 400	SHARED OR NO POLE	1	249.5	186.22	–25

3	MHR0070-ST-0640-003-B	Metal Hallide (Reactor Control Gear) 400	SHARED OR NO POLE	1	248.84	167.02	–33
3	MHR0070-ST-0640-003-S	Metal Hallide (Reactor Control Gear) 400	SHARED OR NO POLE	1	249.5	186.22	–25
3	MHR0070-ST-1100-003-B	Metal Hallide (Reactor Control Gear) 400	WOOD POLE	1	428.83	300.25	–30
3	MHR0070-ST-1100-003-S	Metal Hallide (Reactor Control Gear) 400	WOOD POLE	1	429.49	319.44	–26
3	MVA0020-ST-0010-003-B	Mercury Vapour 80	SHARED OR NO POLE	1	133.8	86.13	–36
3	MVA0020-ST-0010-003-S	Mercury Vapour 80	SHARED OR NO POLE	1	133.63	100.10	–25
3	MVA0020-ST-0740-003-B	Mercury Vapour 80	SHARED OR NO POLE	2	159.93	106.15	–34
3	MVA0020-ST-0740-003-S	Mercury Vapour 80	SHARED OR NO POLE	2	159.75	120.11	–25
3	MVA0020-ST-0810-003-B	Mercury Vapour 80	WOOD POLE	1	292.24	203.60	–30
3	MVA0020-ST-0810-003-S	Mercury Vapour 80	WOOD POLE	1	292.07	217.57	–26
3	MVA0020-ST-0990-003-B	Mercury Vapour 80	STEEL POLE	1	409.43	289.67	–29
3	MVA0020-ST-0990-003-S	Mercury Vapour 80	STEEL POLE	1	409.26	303.63	–26
3	MVA0190-ST-0020-003-B	Mercury Vapour 250	SHARED OR NO POLE	1	211.18	137.01	–35
3	MVA0190-ST-0020-003-S	Mercury Vapour 250	SHARED OR NO POLE	1	204.68	148.78	–27
3	MVA0190-ST-0200-003-B	Mercury Vapour 250	WOOD POLE	1	369.62	254.48	–31
3	MVA0190-ST-0200-003-S	Mercury Vapour 250	WOOD POLE	1	363.12	266.25	–27
3	MVA0190-ST-0290-003-B	Mercury Vapour 250	STEEL POLE	1	450.07	318.75	–29
3	MVA0190-ST-0290-003-S	Mercury Vapour 250	STEEL POLE	1	443.57	330.52	–25
3	MVA0190-ST-0370-003-B	Mercury Vapour 250	STEEL POLE	2	503	358.35	–29
3	MVA0190-ST-0370-003-S	Mercury Vapour 250	STEEL POLE	2	496.5	370.12	–25
3	MVA0190-ST-0940-003-B	Mercury Vapour 250	SHARED OR NO POLE	2	264.12	176.61	–33
4	FLU0350-ST-1620-004-B	Compact Fluorescent 1x42	SHARED OR NO POLE	1	62.13	33.59	–46
4	FLU0350-ST-1620-004-S	Compact Fluorescent 1x42	SHARED OR NO POLE	1	56.42	51.37	–9
4	FLU0350-ST-1630-004-B	Compact Fluorescent 1x42	SHARED OR NO POLE	2	62.13	33.59	–46
4	FLU0350-ST-1630-004-S	Compact Fluorescent 1x42	SHARED OR NO POLE	2	56.42	51.37	–9
4	FLU0350-ST-1640-004-B	Compact Fluorescent 1x42	SHARED OR NO POLE	3	62.13	33.59	–46
4	FLU0350-ST-1640-004-S	Compact Fluorescent 1x42	SHARED OR NO POLE	3	56.42	51.37	–9
4	FLU0350-ST-1650-004-B	Compact Fluorescent 1x42	SHARED OR NO POLE	4	62.13	33.59	–46
4	FLU0350-ST-1650-004-S	Compact Fluorescent 1x42	SHARED OR NO POLE	4	56.42	51.37	–9
4	FLU0350-ST-1660-004-B	Compact Fluorescent 1x42	WOOD POLE	1	72.96	43.99	–40
4	FLU0350-ST-1660-004-S	Compact Fluorescent 1x42	WOOD POLE	1	67.25	61.77	–8

4	FLU0350-ST-1670-004-B	Compact Fluorescent 1x42	WOOD POLE	2	72.96	43.99	–40
4	FLU0350-ST-1670-004-S	Compact Fluorescent 1x42	WOOD POLE	2	67.25	61.77	–8
4	FLU0350-ST-1680-004-B	Compact Fluorescent 1x42	WOOD POLE	3	72.96	43.99	–40
4	FLU0350-ST-1680-004-S	Compact Fluorescent 1x42	WOOD POLE	3	67.25	61.77	–8
4	FLU0350-ST-1690-004-B	Compact Fluorescent 1x42	WOOD POLE	4	72.96	43.99	–40
4	FLU0350-ST-1690-004-S	Compact Fluorescent 1x42	WOOD POLE	4	67.25	61.77	–8
4	FLU0350-ST-1700-004-B	Compact Fluorescent 1x42	STEEL POLE	1	72.14	43.19	–40
4	FLU0350-ST-1700-004-S	Compact Fluorescent 1x42	STEEL POLE	1	66.43	60.96	–8
4	FLU0350-ST-1710-004-B	Compact Fluorescent 1x42	STEEL POLE	2	72.14	43.19	–40
4	FLU0350-ST-1710-004-S	Compact Fluorescent 1x42	STEEL POLE	2	66.43	60.96	–8
4	FLU0350-ST-1720-004-B	Compact Fluorescent 1x42	STEEL POLE	3	72.14	43.19	–40
4	FLU0350-ST-1720-004-S	Compact Fluorescent 1x42	STEEL POLE	3	66.43	60.96	–8
4	FLU0350-ST-1730-004-B	Compact Fluorescent 1x42	STEEL POLE	4	72.14	43.19	–40
4	FLU0350-ST-1730-004-S	Compact Fluorescent 1x42	STEEL POLE	4	66.43	60.96	–8
4	FLU0360-ST-1740-004-B	T5 2x14W	SHARED OR NO POLE	1	63.98	33.96	–47
4	FLU0360-ST-1740-004-S	T5 2x14W	SHARED OR NO POLE	1	54.19	49.54	–9
4	FLU0360-ST-1750-004-B	T5 2x14W	SHARED OR NO POLE	2	63.98	33.96	–47
4	FLU0360-ST-1750-004-S	T5 2x14W	SHARED OR NO POLE	2	54.19	49.54	–9
4	FLU0360-ST-1760-004-B	T5 2x14W	SHARED OR NO POLE	3	63.98	33.96	–47
4	FLU0360-ST-1760-004-S	T5 2x14W	SHARED OR NO POLE	3	54.19	49.54	–9
4	FLU0360-ST-1770-004-B	T5 2x14W	SHARED OR NO POLE	4	63.98	33.96	–47
4	FLU0360-ST-1770-004-S	T5 2x14W	SHARED OR NO POLE	4	54.19	49.54	–9
4	FLU0360-ST-1780-004-B	T5 2x14W	WOOD POLE	1	74.81	44.35	–41
4	FLU0360-ST-1780-004-S	T5 2x14W	WOOD POLE	1	65.03	59.93	–8
4	FLU0360-ST-1790-004-B	T5 2x14W	WOOD POLE	2	74.81	44.35	–41
4	FLU0360-ST-1790-004-S	T5 2x14W	WOOD POLE	2	65.03	59.93	–8
4	FLU0360-ST-1800-004-B	T5 2x14W	WOOD POLE	3	74.81	44.35	–41
4	FLU0360-ST-1800-004-S	T5 2x14W	WOOD POLE	3	65.03	59.93	–8
4	FLU0360-ST-1810-004-B	T5 2x14W	WOOD POLE	4	74.81	44.35	–41
4	FLU0360-ST-1810-004-S	T5 2x14W	WOOD POLE	4	65.03	59.93	–8
4	FLU0360-ST-1820-004-B	T5 2x14W	STEEL POLE	1	73.99	43.55	–41

4	FLU0360-ST-1820-004-S	T5 2x14W	STEEL POLE	1	64.21	59.13	–8
4	FLU0360-ST-1830-004-B	T5 2x14W	STEEL POLE	2	73.99	43.55	–41
4	FLU0360-ST-1830-004-S	T5 2x14W	STEEL POLE	2	64.21	59.13	–8
4	FLU0360-ST-1840-004-B	T5 2x14W	STEEL POLE	3	73.99	43.55	–41
4	FLU0360-ST-1840-004-S	T5 2x14W	STEEL POLE	3	64.21	59.13	–8
4	FLU0360-ST-1850-004-B	T5 2x14W	STEEL POLE	4	73.99	43.55	–41
4	FLU0360-ST-1850-004-S	T5 2x14W	STEEL POLE	4	64.21	59.13	–8
4	FLU0370-ST-1860-004-B	T5 2x24W	SHARED OR NO POLE	1	74.18	40.88	–45
4	FLU0370-ST-1860-004-S	T5 2x24W	SHARED OR NO POLE	1	61.1	55.22	–10
4	FLU0370-ST-1870-004-B	T5 2x24W	SHARED OR NO POLE	2	74.18	40.88	–45
4	FLU0370-ST-1870-004-S	T5 2x24W	SHARED OR NO POLE	2	61.1	55.22	–10
4	FLU0370-ST-1880-004-B	T5 2x24W	SHARED OR NO POLE	3	74.18	40.88	–45
4	FLU0370-ST-1880-004-S	T5 2x24W	SHARED OR NO POLE	3	61.1	55.22	–10
4	FLU0370-ST-1900-004-B	T5 2x24W	WOOD POLE	1	85.02	51.27	–40
4	FLU0370-ST-1900-004-S	T5 2x24W	WOOD POLE	1	71.94	65.62	–9
4	FLU0370-ST-1910-004-B	T5 2x24W	WOOD POLE	2	85.02	51.27	–40
4	FLU0370-ST-1910-004-S	T5 2x24W	WOOD POLE	2	71.94	65.62	–9
4	FLU0370-ST-1920-004-B	T5 2x24W	WOOD POLE	3	85.02	51.27	–40
4	FLU0370-ST-1920-004-S	T5 2x24W	WOOD POLE	3	71.94	65.62	–9
4	FLU0370-ST-1930-004-B	T5 2x24W	WOOD POLE	4	85.02	51.27	–40
4	FLU0370-ST-1930-004-S	T5 2x24W	WOOD POLE	4	71.94	65.62	–9
4	FLU0370-ST-1940-004-B	T5 2x24W	STEEL POLE	1	84.19	50.47	–40
4	FLU0370-ST-1940-004-S	T5 2x24W	STEEL POLE	1	71.11	64.82	–9
4	FLU0370-ST-1950-004-B	T5 2x24W	STEEL POLE	2	84.19	50.47	–40
4	FLU0370-ST-1950-004-S	T5 2x24W	STEEL POLE	2	71.11	64.82	–9
4	FLU0370-ST-1960-004-B	T5 2x24W	STEEL POLE	3	84.19	50.47	–40
4	FLU0370-ST-1960-004-S	T5 2x24W	STEEL POLE	3	71.11	64.82	–9
4	FLU0370-ST-1970-004-B	T5 2x24W	STEEL POLE	4	84.19	50.47	–40
4	FLU0370-ST-1970-004-S	T5 2x24W	STEEL POLE	4	71.11	64.82	–9
4	HPS0020-ST-0040-004-B	High Pressure Sodium 70	SHARED OR NO POLE	1	52.61	32.87	–38
4	HPS0020-ST-0040-004-S	High Pressure Sodium 70	SHARED OR NO POLE	1	48.63	43.51	–11

4	HPS0020-ST-0170-004-B	High Pressure Sodium 70	STEEL POLE	1	62.62	42.47	–32
4	HPS0020-ST-0170-004-S	High Pressure Sodium 70	STEEL POLE	1	58.65	53.10	–9
4	HPS0020-ST-0350-004-B	High Pressure Sodium 70	WOOD POLE	1	63.44	43.27	–32
4	HPS0020-ST-0350-004-S	High Pressure Sodium 70	WOOD POLE	1	59.47	53.90	–9
4	HPS0020-ST-0360-004-B	High Pressure Sodium 70	STEEL POLE	1	62.62	42.47	–32
4	HPS0020-ST-0360-004-S	High Pressure Sodium 70	STEEL POLE	1	58.65	53.10	–9
4	HPS0020-ST-0730-004-B	High Pressure Sodium 70	STEEL POLE	2	62.62	42.47	–32
4	HPS0020-ST-0730-004-S	High Pressure Sodium 70	STEEL POLE	2	58.65	53.10	–9
4	HPS0020-ST-0750-004-B	High Pressure Sodium 70	SHARED OR NO POLE	3	52.61	32.87	–38
4	HPS0020-ST-0750-004-S	High Pressure Sodium 70	SHARED OR NO POLE	3	48.63	43.51	–11
4	HPS0020-ST-0880-004-B	High Pressure Sodium 70	STEEL POLE	4	62.62	42.47	–32
4	HPS0020-ST-0880-004-S	High Pressure Sodium 70	STEEL POLE	4	58.65	53.10	–9
4	HPS0020-ST-0890-004-B	High Pressure Sodium 70	SHARED OR NO POLE	2	52.61	32.87	–38
4	HPS0020-ST-0890-004-S	High Pressure Sodium 70	SHARED OR NO POLE	2	48.63	43.51	–11
4	HPS0020-ST-0910-004-B	High Pressure Sodium 70	WOOD POLE	2	63.44	43.27	–32
4	HPS0020-ST-0910-004-S	High Pressure Sodium 70	WOOD POLE	2	59.47	53.90	–9
4	HPS0020-TA-0090-004-B	High Pressure Sodium 70	SHARED OR NO POLE	1	44.78	30.65	–32
4	HPS0020-TA-0090-004-S	High Pressure Sodium 70	SHARED OR NO POLE	1	42.43	37.07	–13
4	HPS0020-TA-0140-004-B	High Pressure Sodium 70	WOOD POLE	1	55.62	41.05	–26
4	HPS0020-TA-0140-004-S	High Pressure Sodium 70	WOOD POLE	1	53.27	47.46	–11
4	HPS0020-TA-0170-004-B	High Pressure Sodium 70	STEEL POLE	1	54.79	40.24	–27
4	HPS0020-TA-0170-004-S	High Pressure Sodium 70	STEEL POLE	1	52.44	46.66	–11
4	HPS0090-ST-0050-004-B	High Pressure Sodium 150	SHARED OR NO POLE	1	65.21	35.02	–46
4	HPS0090-ST-0050-004-S	High Pressure Sodium 150	SHARED OR NO POLE	1	54.91	49.69	–9
4	HPS0090-ST-0220-004-B	High Pressure Sodium 150	WOOD POLE	1	76.04	45.42	–40
4	HPS0090-ST-0220-004-S	High Pressure Sodium 150	WOOD POLE	1	65.75	60.09	–9
4	HPS0090-ST-0310-004-B	High Pressure Sodium 150	STEEL POLE	1	75.22	44.62	–41
4	HPS0090-ST-0310-004-S	High Pressure Sodium 150	STEEL POLE	1	64.93	59.29	–9
4	HPS0090-ST-0690-004-B	High Pressure Sodium 150	STEEL POLE	2	75.22	44.62	–41
4	HPS0090-ST-0690-004-S	High Pressure Sodium 150	STEEL POLE	2	64.93	59.29	–9
4	HPS0090-ST-0710-004-B	High Pressure Sodium 150	STEEL POLE	3	75.22	44.62	–41

4	HPS0090-ST-0710-004-S	High Pressure Sodium 150	STEEL POLE	3	64.93	59.29	–9
4	HPS0090-ST-0720-004-B	High Pressure Sodium 150	STEEL POLE	4	75.22	44.62	–41
4	HPS0090-ST-0720-004-S	High Pressure Sodium 150	STEEL POLE	4	64.93	59.29	–9
4	HPS0090-ST-0980-004-B	High Pressure Sodium 150	WOOD POLE	2	76.04	45.42	–40
4	HPS0090-ST-0980-004-S	High Pressure Sodium 150	WOOD POLE	2	65.75	60.09	–9
4	HPS0090-ST-1010-004-B	High Pressure Sodium 150	SHARED OR NO POLE	2	65.21	35.02	–46
4	HPS0090-ST-1010-004-S	High Pressure Sodium 150	SHARED OR NO POLE	2	54.91	49.69	–9
4	HPS0090-ST-1360-004-B	High Pressure Sodium 150	R/BOUT COLUMN	3	75.22	44.62	–41
4	HPS0090-ST-1360-004-S	High Pressure Sodium 150	R/BOUT COLUMN	3	64.93	59.29	–9
4	HPS0090-TA-0050-004-B	High Pressure Sodium 150	SHARED OR NO POLE	1	55.17	38.04	–31
4	HPS0090-TA-0050-004-S	High Pressure Sodium 150	SHARED OR NO POLE	1	46.26	40.82	–12
4	HPS0110-ST-0060-004-B	High Pressure Sodium 250	SHARED OR NO POLE	1	66.61	36.13	–46
4	HPS0110-ST-0060-004-S	High Pressure Sodium 250	SHARED OR NO POLE	1	56.2	50.75	–10
4	HPS0110-ST-0230-004-B	High Pressure Sodium 250	WOOD POLE	1	77.45	46.52	–40
4	HPS0110-ST-0230-004-S	High Pressure Sodium 250	WOOD POLE	1	67.03	61.15	–9
4	HPS0110-ST-0320-004-B	High Pressure Sodium 250	STEEL POLE	1	76.62	45.72	–40
4	HPS0110-ST-0320-004-S	High Pressure Sodium 250	STEEL POLE	1	66.21	60.35	–9
4	HPS0110-ST-0390-004-B	High Pressure Sodium 250	STEEL POLE	2	76.62	45.72	–40
4	HPS0110-ST-0390-004-S	High Pressure Sodium 250	STEEL POLE	2	66.21	60.35	–9
4	HPS0110-ST-0430-004-B	High Pressure Sodium 250	STEEL POLE	3	76.62	45.72	–40
4	HPS0110-ST-0430-004-S	High Pressure Sodium 250	STEEL POLE	3	66.21	60.35	–9
4	HPS0110-ST-0470-004-B	High Pressure Sodium 250	STEEL POLE	4	76.62	45.72	–40
4	HPS0110-ST-0470-004-S	High Pressure Sodium 250	STEEL POLE	4	66.21	60.35	–9
4	HPS0110-ST-0550-004-B	High Pressure Sodium 250	R/BOUT COLUMN	3	76.62	45.72	–40
4	HPS0110-ST-0550-004-S	High Pressure Sodium 250	R/BOUT COLUMN	3	66.21	60.35	–9
4	HPS0110-ST-0590-004-B	High Pressure Sodium 250	R/BOUT COLUMN	4	76.62	45.72	–40
4	HPS0110-ST-0590-004-S	High Pressure Sodium 250	R/BOUT COLUMN	4	66.21	60.35	–9
4	HPS0110-ST-0610-004-B	High Pressure Sodium 250	SHARED OR NO POLE	1	66.61	36.13	–46
4	HPS0110-ST-0610-004-S	High Pressure Sodium 250	SHARED OR NO POLE	1	56.2	50.75	–10
4	HPS0110-ST-0650-004-B	High Pressure Sodium 250	SHARED OR NO POLE	2	66.61	36.13	–46
4	HPS0110-ST-0650-004-S	High Pressure Sodium 250	SHARED OR NO POLE	2	56.2	50.75	–10

4	HPS0110-ST-0760-004-B	High Pressure Sodium 250	WOOD POLE	2	77.45	46.52	–40
4	HPS0110-ST-0760-004-S	High Pressure Sodium 250	WOOD POLE	2	67.03	61.15	–9
4	HPS0110-ST-0930-004-B	High Pressure Sodium 250	WOOD POLE	3	77.45	46.52	–40
4	HPS0110-ST-0930-004-S	High Pressure Sodium 250	WOOD POLE	3	67.03	61.15	–9
4	HPS0110-ST-0960-004-B	High Pressure Sodium 250	SHARED OR NO POLE	2	66.61	36.13	–46
4	HPS0110-ST-0960-004-S	High Pressure Sodium 250	SHARED OR NO POLE	2	56.2	50.75	–10
4	HPS0110-ST-0970-004-B	High Pressure Sodium 250	SHARED OR NO POLE	4	66.61	36.13	–46
4	HPS0110-ST-0970-004-S	High Pressure Sodium 250	SHARED OR NO POLE	4	56.2	50.75	–10
4	HPS0110-ST-1070-004-B	High Pressure Sodium 250	WOOD POLE	1	77.45	46.52	–40
4	HPS0110-ST-1070-004-S	High Pressure Sodium 250	WOOD POLE	1	67.03	61.15	–9
4	HPS0110-ST-1120-004-B	High Pressure Sodium 250	STEEL POLE	1	76.62	45.72	–40
4	HPS0110-ST-1120-004-S	High Pressure Sodium 250	STEEL POLE	1	66.21	60.35	–9
4	HPS0110-ST-1330-004-B	High Pressure Sodium 250	STEEL POLE	1	76.62	45.72	–40
4	HPS0110-ST-1330-004-S	High Pressure Sodium 250	STEEL POLE	1	66.21	60.35	–9
4	HPS0110-ST-1340-004-B	High Pressure Sodium 250	STEEL POLE	2	76.62	45.72	–40
4	HPS0110-ST-1340-004-S	High Pressure Sodium 250	STEEL POLE	2	66.21	60.35	–9
4	HPS0110-ST-1380-004-B	High Pressure Sodium 250	R/BOUT COLUMN	3	76.62	45.72	–40
4	HPS0110-ST-1380-004-S	High Pressure Sodium 250	R/BOUT COLUMN	3	66.21	60.35	–9
4	HPS0110-ST-1450-004-B	High Pressure Sodium 250	R/BOUT COLUMN	4	76.62	45.72	–40
4	HPS0110-ST-1450-004-S	High Pressure Sodium 250	R/BOUT COLUMN	4	66.21	60.35	–9
4	HPS0110-TA-0060-004-B	High Pressure Sodium 250	SHARED OR NO POLE	1	50.7	34.26	–32
4	HPS0110-TA-0060-004-S	High Pressure Sodium 250	SHARED OR NO POLE	1	42.7	37.90	–11
4	HPS0110-TA-0320-004-B	High Pressure Sodium 250	STEEL POLE	1	60.71	43.85	–28
4	HPS0110-TA-0320-004-S	High Pressure Sodium 250	STEEL POLE	1	52.71	47.49	–10
4	HPS0110-TA-0590-004-B	High Pressure Sodium 250	R/BOUT COLUMN	4	60.71	43.85	–28
4	HPS0110-TA-0590-004-S	High Pressure Sodium 250	R/BOUT COLUMN	4	52.71	47.49	–10
4	HPS0110-TA-1120-004-B	High Pressure Sodium 250	STEEL POLE	1	60.71	43.85	–28
4	HPS0110-TA-1120-004-S	High Pressure Sodium 250	STEEL POLE	1	52.71	47.49	–10
4	HPS0170-ST-0070-004-B	High Pressure Sodium 400	SHARED OR NO POLE	1	71.89	39.80	–45
4	HPS0170-ST-0070-004-S	High Pressure Sodium 400	SHARED OR NO POLE	1	59.86	53.76	–10
4	HPS0170-ST-0240-004-B	High Pressure Sodium 400	WOOD POLE	1	82.72	50.19	–39

4	HPS0170-ST-0240-004-S	High Pressure Sodium 400	WOOD POLE	1	70.69	64.16	–9
4	HPS0170-ST-0270-004-B	High Pressure Sodium 400	R/BOUT COLUMN	3	81.9	49.39	–40
4	HPS0170-ST-0270-004-S	High Pressure Sodium 400	R/BOUT COLUMN	3	69.87	63.36	–9
4	HPS0170-ST-0330-004-B	High Pressure Sodium 400	STEEL POLE	1	81.9	49.39	–40
4	HPS0170-ST-0330-004-S	High Pressure Sodium 400	STEEL POLE	1	69.87	63.36	–9
4	HPS0170-ST-0400-004-B	High Pressure Sodium 400	STEEL POLE	2	81.9	49.39	–40
4	HPS0170-ST-0400-004-S	High Pressure Sodium 400	STEEL POLE	2	69.87	63.36	–9
4	HPS0170-ST-0440-004-B	High Pressure Sodium 400	STEEL POLE	3	81.9	49.39	–40
4	HPS0170-ST-0440-004-S	High Pressure Sodium 400	STEEL POLE	3	69.87	63.36	–9
4	HPS0170-ST-0480-004-B	High Pressure Sodium 400	STEEL POLE	4	81.9	49.39	–40
4	HPS0170-ST-0480-004-S	High Pressure Sodium 400	STEEL POLE	4	69.87	63.36	–9
4	HPS0170-ST-0560-004-B	High Pressure Sodium 400	R/BOUT COLUMN	3	81.9	49.39	–40
4	HPS0170-ST-0560-004-S	High Pressure Sodium 400	R/BOUT COLUMN	3	69.87	63.36	–9
4	HPS0170-ST-0600-004-B	High Pressure Sodium 400	R/BOUT COLUMN	4	81.9	49.39	–40
4	HPS0170-ST-0600-004-S	High Pressure Sodium 400	R/BOUT COLUMN	4	69.87	63.36	–9
4	HPS0170-ST-0620-004-B	High Pressure Sodium 400	SHARED OR NO POLE	1	71.89	39.80	–45
4	HPS0170-ST-0620-004-S	High Pressure Sodium 400	SHARED OR NO POLE	1	59.86	53.76	–10
4	HPS0170-ST-0660-004-B	High Pressure Sodium 400	SHARED OR NO POLE	2	71.89	39.80	–45
4	HPS0170-ST-0660-004-S	High Pressure Sodium 400	SHARED OR NO POLE	2	59.86	53.76	–10
4	HPS0170-ST-0770-004-B	High Pressure Sodium 400	WOOD POLE	2	82.72	50.19	–39
4	HPS0170-ST-0770-004-S	High Pressure Sodium 400	WOOD POLE	2	70.69	64.16	–9
4	HPS0170-ST-0900-004-B	High Pressure Sodium 400	WOOD POLE	2	82.72	50.19	–39
4	HPS0170-ST-0900-004-S	High Pressure Sodium 400	WOOD POLE	2	70.69	64.16	–9
4	HPS0170-ST-1030-004-B	High Pressure Sodium 400	SHARED OR NO POLE	2	71.89	39.80	–45
4	HPS0170-ST-1030-004-S	High Pressure Sodium 400	SHARED OR NO POLE	2	59.86	53.76	–10
4	HPS0170-ST-1100-004-B	High Pressure Sodium 400	WOOD POLE	1	82.72	50.19	–39
4	HPS0170-ST-1100-004-S	High Pressure Sodium 400	WOOD POLE	1	70.69	64.16	–9
4	HPS0170-ST-1170-004-B	High Pressure Sodium 400	STEEL POLE	1	81.9	49.39	–40
4	HPS0170-ST-1170-004-S	High Pressure Sodium 400	STEEL POLE	1	69.87	63.36	–9
4	MHR0060-ST-0060-004-B	Metal Hallide (Reactor Control Gear) 250	SHARED OR NO POLE	1	87.65	59.73	–32
4	MHR0060-ST-0060-004-S	Metal Hallide (Reactor Control Gear) 250	SHARED OR NO POLE	1	88.94	79.44	–11

4	MHR0060-ST-0320-004-B	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	1	97.66	69.32	–29
4	MHR0060-ST-0320-004-S	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	1	98.95	89.03	–10
4	MHR0060-ST-0390-004-B	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	2	97.66	69.32	–29
4	MHR0060-ST-0390-004-S	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	2	98.95	89.03	–10
4	MHR0060-ST-0430-004-B	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	3	97.66	69.32	–29
4	MHR0060-ST-0430-004-S	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	3	98.95	89.03	–10
4	MHR0060-ST-0610-004-B	Metal Hallide (Reactor Control Gear) 250	SHARED OR NO POLE	1	87.65	59.73	–32
4	MHR0060-ST-0610-004-S	Metal Hallide (Reactor Control Gear) 250	SHARED OR NO POLE	1	88.94	79.44	–11
4	MHR0060-ST-0960-004-B	Metal Hallide (Reactor Control Gear) 250	SHARED OR NO POLE	2	87.65	59.73	–32
4	MHR0060-ST-0960-004-S	Metal Hallide (Reactor Control Gear) 250	SHARED OR NO POLE	2	88.94	79.44	–11
4	MHR0060-ST-1120-004-B	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	1	97.66	69.32	–29
4	MHR0060-ST-1120-004-S	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	1	98.95	89.03	–10
4	MHR0060-ST-1270-004-B	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	1	97.66	69.32	–29
4	MHR0060-ST-1270-004-S	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	1	98.95	89.03	–10
4	MHR0060-ST-1280-004-B	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	2	97.66	69.32	–29
4	MHR0060-ST-1280-004-S	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	2	98.95	89.03	–10
4	MHR0060-ST-1290-004-B	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	4	97.66	69.32	–29
4	MHR0060-ST-1290-004-S	Metal Hallide (Reactor Control Gear) 250	STEEL POLE	4	98.95	89.03	–10
4	MHR0070-ST-0070-004-B	Metal Hallide (Reactor Control Gear) 400	SHARED OR NO POLE	1	92.1	63.39	–31
4	MHR0070-ST-0070-004-S	Metal Hallide (Reactor Control Gear) 400	SHARED OR NO POLE	1	92.76	82.58	–11
4	MHR0070-ST-0640-004-B	Metal Hallide (Reactor Control Gear) 400	SHARED OR NO POLE	1	92.1	63.39	–31
4	MHR0070-ST-0640-004-S	Metal Hallide (Reactor Control Gear) 400	SHARED OR NO POLE	1	92.76	82.58	–11
4	MHR0070-ST-0680-004-B	Metal Hallide (Reactor Control Gear) 400	SHARED OR NO POLE	2	92.1	63.39	–31
4	MHR0070-ST-0680-004-S	Metal Hallide (Reactor Control Gear) 400	SHARED OR NO POLE	2	92.76	82.58	–11
4	MHR0070-ST-1100-004-B	Metal Hallide (Reactor Control Gear) 400	WOOD POLE	1	102.94	73.78	–28
4	MHR0070-ST-1100-004-S	Metal Hallide (Reactor Control Gear) 400	WOOD POLE	1	103.6	92.97	–10
4	MVA0020-ST-0010-004-B	Mercury Vapour 80	SHARED OR NO POLE	1	48.76	29.84	–39
4	MVA0020-ST-0010-004-S	Mercury Vapour 80	SHARED OR NO POLE	1	48.59	43.81	–10
4	MVA0020-ST-0110-004-B	Mercury Vapour 80	SHARED OR NO POLE	1	48.76	29.84	–39
4	MVA0020-ST-0110-004-S	Mercury Vapour 80	SHARED OR NO POLE	1	48.59	43.81	–10
4	MVA0020-ST-0740-004-B	Mercury Vapour 80	SHARED OR NO POLE	2	48.76	29.84	–39

4	MVA0020-ST-0740-004-S	Mercury Vapour 80	SHARED OR NO POLE	2	48.59	43.81	–10
4	MVA0020-ST-0810-004-B	Mercury Vapour 80	WOOD POLE	1	59.6	40.24	–32
4	MVA0020-ST-0810-004-S	Mercury Vapour 80	WOOD POLE	1	59.43	54.20	–9
4	MVA0020-ST-0990-004-B	Mercury Vapour 80	STEEL POLE	1	58.78	39.44	–33
4	MVA0020-ST-0990-004-S	Mercury Vapour 80	STEEL POLE	1	58.6	53.40	–9
4	MVA0020-ST-1000-004-B	Mercury Vapour 80	STEEL POLE	2	58.78	39.44	–33
4	MVA0020-ST-1000-004-S	Mercury Vapour 80	STEEL POLE	2	58.6	53.40	–9
4	MVA0020-ST-1260-004-B	Mercury Vapour 80	WOOD POLE	2	59.6	40.24	–32
4	MVA0020-ST-1260-004-S	Mercury Vapour 80	WOOD POLE	2	59.43	54.20	–9
4	MVA0190-ST-0020-004-B	Mercury Vapour 250	SHARED OR NO POLE	1	62.59	39.33	–37
4	MVA0190-ST-0020-004-S	Mercury Vapour 250	SHARED OR NO POLE	1	56.09	51.10	–9
4	MVA0190-ST-0200-004-B	Mercury Vapour 250	WOOD POLE	1	73.43	49.72	–32
4	MVA0190-ST-0200-004-S	Mercury Vapour 250	WOOD POLE	1	66.92	61.49	–8
4	MVA0190-ST-0290-004-B	Mercury Vapour 250	STEEL POLE	1	72.6	48.92	–33
4	MVA0190-ST-0290-004-S	Mercury Vapour 250	STEEL POLE	1	66.1	60.69	–8
4	MVA0190-ST-0370-004-B	Mercury Vapour 250	STEEL POLE	2	72.6	48.92	–33
4	MVA0190-ST-0370-004-S	Mercury Vapour 250	STEEL POLE	2	66.1	60.69	–8

EnergyAustralia

Tariff charges 2009-10 ($ p.a)		Tariff 3					Tariff 4				
		EA proposed	AER	Change	AER final	% Change	EA proposed	AER	% Change	AER final	% Change
		Jan-09	Mar-09		Apr-09		Jan-09	Mar-09		Apr-09	
0.5	Bracket	24.4	24.46	0	15.00	–39	0	0	–	0.00	0
0.6	Bracket	24.4	24.46	0	15.00	–39	0	0	–	0.00	0
1	Bracket	23.53	23.59	0	14.32	–39	0	0	–	0.00	0
1.2	Bracket	23.53	23.59	0	14.32	–39	0	0	–	0.00	0
1.5	Bracket	78.57	78.22	0	57.12	–27	0	0	–	0.00	0
2	Bracket	29.03	29.05	0	18.60	–36	0	0	–	0.00	0
2.5	Bracket	45.8	29.05	–37	18.60	–59	0	0	–	0.00	0
3	Bracket	62.32	45.44	–27	31.44	–50	0	0	–	0.00	0
3.5	Bracket	64.82	47.92	–26	33.38	–48	0	0	–	0.00	0
4	Bracket	64.82	47.92	–26	33.38	–48	0	0	–	0.00	0
4.5	Bracket	71.82	54.88	–24	38.83	–46	0	0	–	0.00	0
5	Bracket	69.57	52.64	–24	37.08	–47	0	0	–	0.00	0
6	Bracket	89.59	72.51	–19	52.64	–41	0	0	–	0.00	0
6.5	Bracket	89.59	72.51	–19	52.64	–41	0	0	–	0.00	0
7	Bracket	89.59	72.51	–19	52.64	–41	0	0	–	0.00	0
8	Bracket	89.59	72.51	–19	52.64	–41	0	0	–	0.00	0
1*40W TF	Luminaire	12.45	12.38	–1	11.35	–9	0	0	–	0.00	0
1*80W TF	Luminaire	10.08	10.03	0	9.09	–10	0	0	–	0.00	0
1000W MBF	Luminaire	33.96	31.88	–6	30.13	–11	0	0	–	0.00	0
1000W SON	Luminaire	173.42	170.29	–2	163.38	–6	0	0	–	0.00	0
1000W SON Floodlight	Luminaire	91.51	89	–3	85.11	–7	0	0	–	0.00	0
1000W/1500W MBI Floodlight	Luminaire	132.08	129.26	–2	123.88	–6	0	0	–	0.00	0
100W MBI	Luminaire	29.58	27.54	–7	25.94	–12	0	0	–	0.00	0

100W MBI Floodlight	Luminaire	33.96	31.88	–6	30.13	–11	0	0	–	0.00	0
100W SON	Luminaire	25.74	23.73	–8	22.27	–13	0	0	–	0.00	0
100W SON - PARKVILLE	#N/A	#N/A	#N/A	#N/A	121.35	#N/A	#N/A	#N/A	#N/A	0.00	#N/A
100W SON Floodlight	Luminaire	59.29	57.02	–4	54.33	–8	0	0	–	0.00	0
100W SON -PLAIN	Luminaire	25.74	23.73	–8	22.27	–13	0	0	–	0.00	0
125W MBF	Luminaire	14.36	12.43	–13	11.40	–21	0	0	–	0.00	0
125W MBF - Bourke Hill	Luminaire	89.12	86.63	–3	82.83	–7	0	0	–	0.00	0
125W MBF - Hyde Park	Luminaire	63.4	61.1	–4	58.25	–8	0	0	–	0.00	0
125W MBF - Nostalgia	Luminaire	91.29	88.78	–3	84.91	–7	0	0	–	0.00	0
125W MBF - Parkville	Luminaire	116.31	113.61	–2	108.81	–6	0	0	–	0.00	0
125W MBF Bollard	Luminaire	53.76	51.54	–4	49.05	–9	0	0	–	0.00	0
125W MBF -PLAIN	Luminaire	14.36	12.43	–13	11.40	–21	0	0	–	0.00	0
125w/250w MBF Floodlight	Luminaire	31.04	28.98	–7	27.33	–12	0	0	–	0.00	0
135W SOX	Luminaire	36.88	34.78	–6	32.91	–11	0	0	–	0.00	0
150W SON	Luminaire	24.98	22.97	–8	21.55	–14	0	0	–	0.00	0
150W SON - Hyde Park	Luminaire	63.4	61.1	–4	58.25	–8	0	0	–	0.00	0
150W SON - Parkville	Luminaire	129.43	126.63	–2	121.35	–6	0	0	–	0.00	0
150W SON - Parkway 1	Luminaire	44.38	42.23	–5	40.08	–10	0	0	–	0.00	0
150W SON Floodlight	Luminaire	59.29	57.02	–4	54.33	–8	0	0	–	0.00	0
150W SON GEC ‘Boston 3’	Luminaire	116.31	113.61	–2	108.81	–6	0	0	–	0.00	0
150W/250W MBI Floodlight	Luminaire	78.51	76.1	–3	72.70	–7	0	0	–	0.00	0
180W SOX	Luminaire	43.51	41.36	–5	39.25	–10	0	0	–	0.00	0
2*14W TF - T5 Pierlite Mk 3	Luminaire	28.07	27.89	–1	26.28	–6	0	0	–	0.00	0
2*175W MBF - Parkway 2	Luminaire	146.4	143.48	–2	137.57	–6	0	0	–	0.00	0
2*20W TF	Luminaire	12.35	12.28	–1	11.26	–9	0	0	–	0.00	0
2*20W TF - WAVERLEY	#N/A	#N/A	#N/A	#N/A	11.26	#N/A	#N/A	#N/A	#N/A	0.00	#N/A
2*250W SON Floodlight	Luminaire	70.03	67.68	–3	64.59	–8	0	0	–	0.00	0
2*26W TF Macquarie Dec. Ball	Luminaire	116.43	115.58	–1	110.71	–5	0	0	–	0.00	0
2*400W MBF - Parkway 2	Luminaire	146.4	143.48	–2	137.57	–6	0	0	–	0.00	0
2*400W MBI Floodlight	Luminaire	148.92	145.98	–2	139.97	–6	0	0	–	0.00	0
2*400W SON Floodlight	Luminaire	162.45	159.4	–2	152.90	–6	0	0	–	0.00	0

2*40W TF	Luminaire	28.38	28.2	–1	26.58	–6	0	0	–	0.00	0
2*70W SON - Bourke Hill	Luminaire	164.48	163.27	–1	156.62	–5	0	0	–	0.00	0
2*80W MBF - Bourke Hill	Luminaire	73.79	73.26	–1	69.97	–5	0	0	–	0.00	0
250W MBF	Luminaire	23.99	21.99	–8	20.60	–14	0	0	–	0.00	0
250W MBF - Parkville	Luminaire	119.88	117.16	–2	112.23	–6	0	0	–	0.00	0
250W MBF - Parkway 1	Luminaire	44.38	42.23	–5	40.08	–10	0	0	–	0.00	0
250W MBI - Smartpole	Luminaire	3.73	1.88	–50	1.24	–67	0	0	–	0.00	0
250W SON	Luminaire	23.52	21.52	–9	20.15	–14	0	0	–	0.00	0
250W SON - Parkville	Luminaire	141.63	138.74	–2	133.01	–6	0	0	–	0.00	0
250W SON - Parkway 1	Luminaire	44.38	42.23	–5	40.08	–10	0	0	–	0.00	0
250W SON Floodlight	Luminaire	52.96	50.74	–4	48.28	–9	0	0	–	0.00	0
250W SON GEC ‘Boston 3’	Luminaire	118.95	116.24	–2	111.34	–6	0	0	–	0.00	0
2nd Light non-TRL	Support	0	0	–	0.00	0	0	0	–	0.00	0
2nd Light TRL	Support	0	0	–	0.00	0	0	0	–	0.00	0
2x14W TF - T5 Pierlight	Luminaire	18.03	17.92	–1	17.48	–3	0	0	–	0.00	0
3*400W MBF - Parkway 3	Luminaire	146.4	143.48	–2	137.57	–6	0	0	–	0.00	0
4*1000W MBF	Luminaire	124.66	121.9	–2	116.79	–6	0	0	–	0.00	0
4*20W TF	Luminaire	54.8	54.41	–1	51.82	–5	0	0	–	0.00	0
4*20W TF - WAVERLEY	Luminaire	54.8	54.41	–1	51.82	–5	0	0	–	0.00	0
4*250W SON	Luminaire	81.7	79.26	–3	75.74	–7	0	0	–	0.00	0
4*40W TF	Luminaire	68.16	67.68	–1	64.59	–5	0	0	–	0.00	0
4*40W TF - WAVERLEY	Luminaire	62.11	61.67	–1	58.81	–5	0	0	–	0.00	0
4*600W SON	Luminaire	136.33	133.48	–2	127.94	–6	0	0	–	0.00	0
400W MBF	Luminaire	32.28	30.21	–6	28.52	–12	0	0	–	0.00	0
400W MBF - Parkway 1	Luminaire	70.03	67.68	–3	64.59	–8	0	0	–	0.00	0
400W MBF Floodlight	Luminaire	79.31	76.89	–3	73.46	–7	0	0	–	0.00	0
400W MBI - Smartpole	Luminaire	3.73	1.88	–50	1.24	–67	0	0	–	0.00	0
400W MBI Floodlight	Luminaire	54.12	51.88	–4	49.38	–9	0	0	–	0.00	0
400W SON	Luminaire	32.34	30.27	–6	28.57	–12	0	0	–	0.00	0
400W SON - Parkway 1	Luminaire	44.38	42.23	–5	40.08	–10	0	0	–	0.00	0
400W SON Floodlight	Luminaire	64.12	61.81	–4	58.94	–8	0	0	–	0.00	0

40W SOX	#N/A	#N/A	#N/A	#N/A	11.35	#N/A	#N/A	#N/A	#N/A	0.00	#N/A
42W MBF Sylvania Sub Eco CFL	Luminaire	23.44	23.29	–1	21.86	–7	0	0	–	0.00	0
500W MBI Floodlight	Luminaire	74.8	72.41	–3	69.15	–8	0	0	–	0.00	0
50W MBF	Luminaire	12.5	12.43	–1	11.40	–9	0	0	–	0.00	0
50W MBF - PLAIN	Luminaire	12.5	12.43	–1	11.40	–9	0	0	–	0.00	0
50W MBF - Bourke Hill	Luminaire	73.79	73.26	–1	69.97	–5	0	0	–	0.00	0
50W MBF - Nostalgia	Luminaire	72.27	71.76	–1	68.52	–5	0	0	–	0.00	0
50W MBF Bollard	Luminaire	40.32	40.04	–1	37.98	–6	0	0	–	0.00	0
50W SON	Luminaire	12.12	12.06	–1	11.04	–9	0	0	–	0.00	0
50W SON - BOURKE HILL	#N/A	#N/A	#N/A	#N/A	80.30	#N/A	#N/A	#N/A	#N/A	0.00	#N/A
50W SON - Nostalgia	Luminaire	28.76	28.57	–1	26.94	–6	0	0	–	0.00	0
60W SOX	#N/A	#N/A	#N/A	#N/A	11.35	#N/A	#N/A	#N/A	#N/A	0.00	#N/A
700W MBF	Luminaire	36.63	34.53	–6	32.67	–11	0	0	–	0.00	0
70W MBI	Luminaire	20.82	20.69	–1	19.36	–7	0	0	–	0.00	0
70W MBI - Macquarie Dec. Ball	Luminaire	132.75	129.92	–2	124.52	–6	0	0	–	0.00	0
70W SON	Luminaire	12.25	12.18	–1	11.16	–9	0	0	–	0.00	0
70W SON - Bourke Hill	Luminaire	84.61	83.99	–1	80.30	–5	0	0	–	0.00	0
70W SON - GEC Boston 2	Luminaire	101.94	101.2	–1	96.86	–5	0	0	–	0.00	0
70W SON - Nostalgia	Luminaire	77.71	77.15	–1	73.71	–5	0	0	–	0.00	0
70W SON - PARKVILLE	#N/A	#N/A	#N/A	#N/A	96.86	#N/A	#N/A	#N/A	#N/A	0.00	#N/A
70W SON - Regal/Flinders Enc	Luminaire	151.04	149.93	–1	143.78	–5	0	0	–	0.00	0
70W SON Bollard	Luminaire	55.17	54.78	–1	52.17	–5	0	0	–	0.00	0
70W SON Floodlight	Luminaire	23.06	22.91	–1	21.49	–7	0	0	–	0.00	0
70W SON -PLAIN	Luminaire	12.25	12.18	–1	11.16	–9	0	0	–	0.00	0
750W MBI Floodlight	Luminaire	74.8	72.41	–3	69.15	–8	0	0	–	0.00	0
80W MBF	Luminaire	11.7	11.64	–1	10.63	–9	0	0	–	0.00	0
80W MBF - PLAIN	Luminaire	11.7	11.64	–1	10.63	–9	0	0	–	0.00	0
80W MBF - Bega+Curve Bracket	Luminaire	131.68	130.71	–1	125.28	–5	0	0	–	0.00	0
80W MBF - Bourke Hill	Luminaire	52.38	52.02	–1	49.51	–5	0	0	–	0.00	0
80W MBF - GEC Boston 2	Luminaire	101.94	101.2	–1	96.86	–5	0	0	–	0.00	0
80w MBF - Nostalgia	Luminaire	72.27	71.76	–1	68.52	–5	0	0	–	0.00	0

80W MBF - Regal/Flinders Enc	Luminaire	145.07	144	–1	138.07	–5	0	0	–	0.00	0
80W MBF - Sylvania Suburban	Luminaire	11.87	11.81	–1	10.80	–9	0	0	–	0.00	0
80W MBF Bollard	Luminaire	40.32	40.04	–1	37.98	–6	0	0	–	0.00	0
80W MBF TOORAK	Luminaire	64.41	63.95	–1	61.00	–5	0	0	–	0.00	0
90W SOX	Luminaire	56.77	54.52	–4	51.92	–9	0	0	–	0.00	0
Bollard	Support	124.91	123.61	–1	116.29	–7	0	0	–	0.00	0
C4	Bracket	113.1	95.85	–15	70.93	–37	0	0	–	0.00	0
Column 10.5m-13.5m	Support	243.66	241.13	–1	226.85	–7	0	0	–	0.00	0
Column 14m-15m	Support	223.96	221.64	–1	208.51	–7	0	0	–	0.00	0
Column 2.5m-3.5m	Support	196.17	194.14	–1	182.64	–7	0	0	–	0.00	0
Column 4-6.5m Orion Water Pipe	Support	212.89	210.68	–1	198.20	–7	0	0	–	0.00	0
Column 4m-6.5m	Support	239.84	237.36	–1	223.30	–7	0	0	–	0.00	0
Column 7m-10m	Support	233.21	230.79	–1	217.12	–7	0	0	–	0.00	0
Decorative Column	Support	257.19	254.52	–1	239.45	–7	0	0	–	0.00	0
Dedicated Support & Conductor	Support	249.13	247.25	–1	193.73	–22	0	0	–	0.00	0
Hyde Park Standard	Support	320.08	316.77	–1	298.01	–7	0	0	–	0.00	0
INC1*100	Lamp	220.54	181.21	–18	121.98	–45	220.54	181.21	–18	121.98	–45
INC1*1000	Lamp	333.52	273.28	–18	215.96	–35	333.52	273.28	–18	215.96	–35
INC1*1440	Lamp	216.57	177.97	–18	118.67	–45	216.57	177.97	–18	118.67	–45
INC1*150	Lamp	223.11	183.31	–18	124.12	–44	223.11	183.31	–18	124.12	–44
INC1*200	Lamp	225.22	185.03	–18	125.87	–44	225.22	185.03	–18	125.87	–44
INC1*300	Lamp	249.31	204.66	–18	145.91	–41	249.31	204.66	–18	145.91	–41
INC1*40	Lamp	216.57	177.97	–18	122.07	–44	216.57	177.97	–18	122.07	–44
INC1*500	Lamp	286.74	235.15	–18	177.05	–38	286.74	235.15	–18	177.05	–38
INC1*60	Lamp	220.54	181.21	–18	121.98	–45	220.54	181.21	–18	121.98	–45
INC1*75	Lamp	220.54	181.21	–18	121.98	–45	220.54	181.21	–18	121.98	–45
INC3*100	Lamp	228.49	187.69	–18	128.60	–44	228.49	187.69	–18	128.60	–44
Incandescent	Luminaire	5.84	5.82	0	5.04	–14	0	0	–	0.00	0
Macquarie Standard	Support	200.56	198.48	–1	50.39	–75	0	0	–	0.00	0
Mast 15.5m-30m	Support	235.04	232.6	–1	218.82	–7	0	0	–	0.00	0
Mast 23m	Support	235.04	232.6	–1	218.82	–7	0	0	–	0.00	0

Mast 25m	Support	235.04	232.6	–1	218.82	–7	0	0	–	0.00	0
MBF1*1000	Lamp	87.05	72.02	–17	83.08	–5	87.05	72.02	–17	83.08	–5
MBF1*125	Lamp	42.98	35.51	–17	44.09	3	42.98	35.51	–17	44.09	3
MBF1*250	Lamp	44.51	36.78	–17	45.32	2	44.51	36.78	–17	45.32	2
MBF1*400	Lamp	64.51	53.19	–18	45.82	–29	64.51	53.19	–18	45.82	–29
MBF1*42	Lamp	43.24	40.34	–7	39.31	–9	43.24	40.34	–7	39.31	–9
MBF1*50	Lamp	44.51	36.78	–17	42.78	–4	44.51	36.78	–17	42.78	–4
MBF1*500	Lamp	110.36	91.05	–17	92.04	–17	110.36	91.05	–17	92.04	–17
MBF1*700	Lamp	88.11	72.68	–18	73.28	–17	88.11	72.68	–18	73.28	–17
MBF1*80	Lamp	27.18	22.53	–17	39.40	57	27.18	22.53	–17	39.40	57
MBF1*800	Lamp	110.36	91.05	–17	92.04	–17	110.36	91.05	–17	92.04	–17
MBF2*125	Lamp	41.78	34.51	–17	43.12	3	41.78	34.51	–17	43.12	3
MBF2*160	Lamp	39.63	32.72	–17	41.39	4	39.63	32.72	–17	41.39	4
MBF2*175	Lamp	108.18	89.52	–17	96.56	–11	108.18	89.52	–17	96.56	–11
MBF2*400	#N/A	#N/A	#N/A	#N/A	45.82	#N/A	#N/A	#N/A	#N/A	45.82	#N/A
MBF2*80	Lamp	29.04	24.07	–17	44.29	53	29.04	24.07	–17	44.29	53
MBF3*160	Lamp	39.63	32.72	–17	41.39	4	39.63	32.72	–17	41.39	4
MBF3*250	Lamp	54.28	44.88	–17	53.19	–2	54.28	44.88	–17	53.19	–2
MBF3*400	Lamp	77.26	63.71	–18	54.67	–29	77.26	63.71	–18	54.67	–29
MBF3*80	Lamp	30.14	24.98	–17	45.26	50	30.14	24.98	–17	45.26	50
MBF4*1000	Lamp	374.75	310.39	–17	326.42	–13	374.75	310.39	–17	326.42	–13
MBF4*80	Lamp	31.6	26.21	–17	46.54	47	31.6	26.21	–17	46.54	47
MBF6*125	Lamp	52.52	43.41	–17	51.77	–1	52.52	43.41	–17	51.77	–1
MBF6*160	Lamp	44.26	36.53	–17	41.39	–6	44.26	36.53	–17	41.39	–6
MBF9*160	Lamp	44.26	36.53	–17	41.39	–6	44.26	36.53	–17	41.39	–6
MBI1*100	Lamp	86.57	71.37	–18	69.33	–20	86.57	71.37	–18	69.33	–20
MBI1*1000	Lamp	161.2	132.97	–18	132.21	–18	161.2	132.97	–18	132.21	–18
MBI1*150	Lamp	134.03	110.55	–18	109.32	–18	134.03	110.55	–18	109.32	–18
MBI1*1500	Lamp	129.14	106.5	–18	105.20	–19	129.14	106.5	–18	105.20	–19
MBI1*250	Lamp	84.29	69.49	–18	67.41	–20	84.29	69.49	–18	67.41	–20
MBI1*3745	Lamp	62.77	51.73	–18	49.28	–21	62.77	51.73	–18	49.28	–21

MBI1*400	Lamp	72.28	59.67	–17	63.92	–12	72.28	59.67	–17	63.92	–12
MBI1*500	Lamp	129.14	106.5	–18	89.96	–30	129.14	106.5	–18	89.96	–30
MBI1*70	Lamp	61.12	50.51	–17	64.32	5	61.12	50.51	–17	64.32	5
MBI1*750	Lamp	141.49	116.88	–17	122.33	–14	141.49	116.88	–17	122.33	–14
MBI2*400	Lamp	93.37	77.1	–17	81.72	–12	93.37	77.1	–17	81.72	–12
MBI4*150	Lamp	51.19	42.23	–18	46.12	–10	51.19	42.23	–18	46.12	–10
NIL	Bracket	0	0	–	0.00	0	0	0	–	0.00	0
O/U	Connection	88.49	88.42	0	89.69	1	78.56	78.56	0	80.20	2
OH	Connection	0	0	–	0.00	0	0	0	–	0.00	0
OH2	Connection	0	0	–	0.00	0	0	0	–	0.00	0
OHS	Connection	0	0	–	0.00	0	0	0	–	0.00	0
Orion Double Arm	Bracket	60.78	60.56	0	43.28	–29	0	0	–	0.00	0
Polo 10.5m decorative 2m outre	Bracket	104.34	103.79	–1	77.16	–26	0	0	–	0.00	0
Polo 4.5m decorative 1.2m outr	Bracket	104.34	103.79	–1	77.16	–26	0	0	–	0.00	0
Private	Support	0	0	0	0.00	0	0	0	–	0.00	0
Rocks Standard	Support	186.81	184.88	–1	173.93	–7	0	0	–	0.00	0
Smartpole A	Support	0	0	–	0.00	0	0	0	–	0.00	0
Smartpole Ab	Support	0	0	–	0.00	0	0	0	–	0.00	0
Smartpole B	Support	0	0	–	0.00	0	0	0	–	0.00	0
Smartpole C	Support	0	0	–	0.00	0	0	0	–	0.00	0
Smartpole Double	Support	0	0	–	0.00	0	0	0	–	0.00	0
Smartpole Single Long	Support	0	0	–	0.00	0	0	0	–	0.00	0
Smartpole Single Short	Support	0	0	–	0.00	0	0	0	–	0.00	0
SON1*100	Lamp	67.15	55.41	–17	56.33	–16	67.15	55.41	–17	56.33	–16
SON1*1000	Lamp	102.34	84.51	–17	82.33	–20	102.34	84.51	–17	82.33	–20
SON1*120	Lamp	60.74	50.11	–17	54.18	–11	60.74	50.11	–17	54.18	–11
SON1*150	Lamp	62.17	51.31	–17	48.44	–22	62.17	51.31	–17	48.44	–22
SON1*220	Lamp	75.43	62.27	–17	66.57	–12	75.43	62.27	–17	66.57	–12
SON1*250	Lamp	60.59	49.99	–17	42.34	–30	60.59	49.99	–17	42.34	–30
SON1*310	Lamp	74.03	61.1	–17	65.39	–12	74.03	61.1	–17	65.39	–12
SON1*360	Lamp	51.19	42.23	–18	46.12	–10	51.19	42.23	–18	46.12	–10

SON1*400	Lamp	61.27	50.55	–17	42.73	–30	61.27	50.55	–17	42.73	–30
SON1*50	Lamp	62.17	51.31	–17	54.18	–13	62.17	51.31	–17	54.18	–13
SON1*70	Lamp	54.02	44.6	–17	52.41	–3	54.02	44.6	–17	52.41	–3
SON2*250	Lamp	75.29	62.11	–18	47.59	–37	75.29	62.11	–18	47.59	–37
SON2*400	Lamp	79.37	65.47	–18	48.35	–39	79.37	65.47	–18	48.35	–39
SON2*70	Lamp	67.32	55.58	–17	61.06	–9	67.32	55.58	–17	61.06	–9
SON3*70	Lamp	78.9	65.15	–17	69.71	–12	78.9	65.15	–17	69.71	–12
SON4*250	Lamp	97.73	80.63	–18	58.08	–41	97.73	80.63	–18	58.08	–41
SON4*600	Lamp	178.93	147.68	–17	149.85	–16	178.93	147.68	–17	149.85	–16
SON4*70	Lamp	90.46	74.7	–17	78.37	–13	90.46	74.7	–17	78.37	–13
SON8*70	Lamp	136.76	112.92	–17	112.97	–17	136.76	112.92	–17	112.97	–17
SOX1*135	Lamp	75.79	62.51	–18	62.90	–17	75.79	62.51	–18	62.90	–17
SOX1*150	Lamp	75.79	62.51	–18	62.90	–17	75.79	62.51	–18	62.90	–17
SOX1*180	Lamp	173.66	143.33	–17	145.41	–16	173.66	143.33	–17	145.41	–16
SOX1*90	Lamp	65.31	53.9	–17	64.48	–1	65.31	53.9	–17	64.48	–1
SUSPENDED 2	#N/A	#N/A	#N/A	#N/A	50.26	#N/A	#N/A	#N/A	#N/A	0.00	#N/A
T1	Bracket	37.1	37.06	0	24.87	–33	0	0	–	0.00	0
T2	Bracket	68.82	51.9	–25	36.50	–47	0	0	–	0.00	0
T2A	Bracket	68.82	51.9	–25	36.50	–47	0	0	–	0.00	0
T3	Bracket	69.57	52.64	–24	37.08	–47	0	0	–	0.00	0
T3A	Bracket	69.57	52.64	–24	37.08	–47	0	0	–	0.00	0
T4	Bracket	67.32	50.41	–25	35.33	–48	0	0	–	0.00	0
T5	Bracket	67.32	50.41	–25	35.33	–48	0	0	–	0.00	0
T6	Bracket	89.59	72.51	–19	52.64	–41	0	0	–	0.00	0
T7	Bracket	83.21	66.17	–20	47.68	–43	0	0	–	0.00	0
TF1*16	Lamp	85.74	70.58	–18	65.05	–24	85.74	70.58	–18	65.05	–24
TF1*176	Lamp	120.63	99.22	–18	65.05	–46	120.63	99.22	–18	65.05	–46
TF1*20	Lamp	86.69	71.37	–18	65.85	–24	86.69	71.37	–18	65.85	–24
TF1*236	Lamp	120.63	99.22	–18	65.05	–46	120.63	99.22	–18	65.05	–46
TF1*26	Lamp	86.79	71.44	–18	65.92	–24	86.79	71.44	–18	65.92	–24
TF1*40	Lamp	86.87	71.5	–18	65.99	–24	86.87	71.5	–18	65.99	–24

TF1*60	#N/A	#N/A	#N/A	#N/A	66.75	#N/A	#N/A	#N/A	#N/A	66.75	#N/A
TF1*80	Lamp	87.77	72.25	–18	66.75	–24	87.77	72.25	–18	66.75	–24
TF2*14 T5	Lamp	56.49	53.53	–5	37.62	–33	56.49	53.53	–5	37.62	–33
TF2*20	Lamp	80.56	78.55	–2	42.66	–47	80.56	78.55	–2	42.66	–47
TF2*26	Lamp	87.81	72.29	–18	66.79	–24	87.81	72.29	–18	66.79	–24
TF2*40	Lamp	87.99	72.44	–18	66.94	–24	87.99	72.44	–18	66.94	–24
TF2*58	Lamp	85.74	70.58	–18	65.05	–24	85.74	70.58	–18	65.05	–24
TF2*80	Lamp	89.82	73.92	–18	68.46	–24	89.82	73.92	–18	68.46	–24
TF3*20	Lamp	88.59	72.93	–18	67.44	–24	88.59	72.93	–18	67.44	–24
TF3*40	Lamp	89.12	73.36	–18	67.89	–24	89.12	73.36	–18	67.89	–24
TF3*80	Lamp	91.85	75.59	–18	70.17	–24	91.85	75.59	–18	70.17	–24
TF4*20	Lamp	89.54	73.7	–18	68.24	–24	89.54	73.7	–18	68.24	–24
TF4*40	Lamp	90.26	74.29	–18	68.83	–24	90.26	74.29	–18	68.83	–24
TF4*80	Lamp	93.88	77.27	–18	71.87	–23	93.88	77.27	–18	71.87	–23
TF5*58	Lamp	85.74	70.58	–18	65.05	–24	85.74	70.58	–18	65.05	–24
TF5*65	Lamp	85.74	70.58	–18	65.05	–24	85.74	70.58	–18	65.05	–24
TF5*80	Lamp	95.92	78.93	–18	73.58	–23	95.92	78.93	–18	73.58	–23
TF6*20	Lamp	91.45	75.27	–18	69.83	–24	91.45	75.27	–18	69.83	–24
TF6*36	Lamp	92.51	76.13	–18	70.72	–24	92.51	76.13	–18	70.72	–24
TF6*80	Lamp	97.95	80.61	–18	75.28	–23	97.95	80.61	–18	75.28	–23
TH Floodlight	Luminaire	144.02	141.11	–2	135.29	–6	0	0	–	0.00	0
TH1*1000	Lamp	61.96	51.14	–17	56.54	–9	61.96	51.14	–17	56.54	–9
TH1*1500	Lamp	59.31	48.95	–17	54.30	–8	59.31	48.95	–17	54.30	–8
TH1*400	Lamp	69.06	57.02	–17	62.53	–9	69.06	57.02	–17	62.53	–9
TH1*500	Lamp	59.31	48.95	–17	50.23	–15	59.31	48.95	–17	50.23	–15
TH1*750	Lamp	62.89	51.92	–17	57.32	–9	62.89	51.92	–17	57.32	–9
UG2	Connection	0	0	–	0.00	0	0	0	–	0.00	0
UGOrDA	Connection	49.21	49.14	0	49.59	1	39.28	39.28	0	40.10	2
UGR1	Connection	85.8	85.69	0	86.68	1	72.02	72.02	0	73.52	2
UGR2	Connection	36.12	36.04	0	36.22	0	26.19	26.19	0	26.73	2
UGS	Connection	9.93	9.85	–1	9.49	–4	0	0	–	0.00	0

UG-SP	Connection	0	0	–	0.00	0	0	0	–	0.00	0
Unknown	Support	0	0	–	0.00	0	0	0	–	0.00	0
Wall	Support	0	0	–	0.00	0	0	0	–	0.00	0
Wood Pole non-TRL	Support	0	0	–	0.00	0	0	0	–	0.00	0
Wood Pole TRL	Support	0	0	–	0.00	0	0	0	–	0.00	0

Integral Energy

Tariff charges 2009-10 ($ p.a)		Tariff 3			
		Integral Energy proposed Jan-09	Integral Energy revised Feb-09	AER final Apr-09	% Change
Luminaires					
Minor road - standard					
F2x14	2x14W Energy Efficient Fluorescent	64.45	86.55	79.37	–8
F2x24	2x24W Energy Efficient Fluorescent	67.03	89.14	81.87	–8
CFL42	1x42W Compact Fluorescent	62.14	84.25	77.60	–8
M50	50W Mercury	51.11	73.22	65.71	–10
M80	80W Mercury	48.11	70.22	61.04	–13
S70	70W Sodium	63.65	85.76	78.07	–9
S100	100W Sodium	62.16	84.27	76.93	–9
MH100	100W Metal Halide	62.99	85.09	77.75	–9
Major road - standard					
S150	150W Sodium	66.54	89.6	75.78	–15
MH150	150W Metal Halide	71.28	94.33	85.70	–9
S250	250W Sodium	78.09	101.14	80.15	–21
MH250	250W Metal Halide	78.32	101.37	92.69	–9
S400	400W Sodium	80.12	103.17	87.63	–15
Minor road - fully cut off (low glare)					
M80	80W Mercury	53.84	75.95	66.05	–13
Major road - fully cut off (low glare)					
S150	150W Sodium	75.2	98.25	83.72	–15
MH150	150W Metal Halide	79.93	102.98	93.64	–9
S250	250W Sodium (inc. PECB)	72.94	95.99	75.42	–21
S250	250W Sodium (w/o PECB)	89.22	112.27	90.35	–20
MH250	250W Metal Halide	89.44	112.5	102.90	–9
S400	400W Sodium	87.61	110.66	94.50	–15
MH400	400W Metal Halide	90.57	113.63	104.30	–8
Post top - standard					
M80	80W Mercury	62.48	84.58	73.98	–13
Floodlight					
S250	250W Sodium	104.59	127.64	104.46	–18
MH250	250W Metal Halide	104.82	127.87	117.00	–8
S400	400W Sodium	109.25	132.3	114.35	–14
MH400	400W Metal Halide	112.21	135.26	124.15	–8
Brackets					
Bracket - minor		30.63	8.53	6.38	–25
Bracket - major		74.67	51.62	38.60	–25
Outreach					
Outreach - minor		32.86	10.76	8.04	–25
Outreach - major		44.52	21.47	16.06	–25
Pole (wood)					
Pole (wood) - minor		177.46	177.46	164.65	–7
Pole (wood) - major		192.31	192.31	177.80	–8
Column (steel)					
Column (steel) - minor		237.25	237.25	214.31	–10
Column (steel) - major		535.37	535.37	478.35	–11

Tariff charges 2009-10 ($ p.a)		Tariff 4			
		Integral Energy proposed Jan-09	Integral Energy revised Feb-09	AER final Apr-09	% Change
Luminaires					
Minor road - standard					
F2x14	2 x 14W Energy Efficient Fluorescent	48.6	54.85	51.39	–6
F2x24	2 x 24W Energy Efficient Fluorescent	50.46	56.71	53.24	–6
CFL42	1 x 42W Compact Fluorescent	51.1	57.35	53.86	–6
M50	50W Mercury	43.1	49.35	44.64	–10
M80	80W Mercury	42.09	48.34	41.56	–14
S70	70W Sodium	54.54	60.79	56.03	–8
S100	100W Sodium	56.15	62.4	57.62	–8
MH100	100W Metal Halide	56.97	63.22	58.44	–8
Major road - standard					
S150	150W Sodium	51.62	57.87	47.74	–18
MH150	150W Metal Halide	56.35	62.6	57.66	–8
S250	250W Sodium	62.97	69.49	52.21	–25
MH250	250W Metal Halide	63.2	69.72	64.75	–7
S400	400W Sodium	64.89	71.41	59.59	–17
Minor road - fully cut off (low glare)					
M80	80W Mercury	43.71	49.97	43.12	–14
Major road - fully cut off (low glare)					
S150	150W Sodium	54.06	60.32	50.20	–17
MH150	150W Metal Halide	58.79	65.05	60.12	–8
S250	250W Sodium (inc. PECB)	61.52	68.03	50.74	–25
S250	250W Sodium (w/o PECB)	66.12	72.64	55.37	–24
MH250	250W Metal Halide	66.35	72.87	67.92	–7
S400	400W Sodium	67.01	73.53	61.72	–16
MH400	400W Metal Halide	69.97	76.49	71.52	–7
Post top - standard					
M80	80W Mercury	46.16	52.41	45.57	–13
Floodlight					
S250	250W Sodium	70.47	76.99	59.74	–22
MH250	250W Metal Halide	70.69	77.21	72.29	–6
S400	400W Sodium	73.13	79.64	67.88	–15
MH400	400W Metal Halide	76.09	82.61	77.67	–6
Brackets					
Bracket - minor		8.66	2.41	2.43	1
Bracket - major		21.12	14.6	14.68	1
Outreach					
Outreach - minor		9.29	3.04	3.06	1
Outreach - major		12.59	6.07	6.11	1
Pole (wood)					
Pole (wood) - minor		97.79	97.79	97.72	0
Pole (wood) - major		97.79	97.79	97.72	0
Column (steel)					
Column (steel) - minor		112.27	112.27	112.53	0
Column (steel) - major		223.46	223.46	224.34	0

Appendix S: Recovery of tax on Integral Energy's gifted assets

Recovery of Tax on Contributed Assets - Tariff 4 only (2009/10 ($))		Integral Energy revised	AER final
Luminaires		**Feb-09**	**Apr-09**
Minor road - standard			
F2x14	2 x 14W Energy Efficient Fluorescent	12.8	12.36
F2x24	2 x 24W Energy Efficient Fluorescent	13.1	12.65
CFL42	1 x 42W Compact Fluorescent	10.9	10.49
M50	50W Mercury	9.6	9.31
M80	80W Mercury	8.8	8.61
S70	70W Sodium	10.1	9.74
S100	100W Sodium	8.8	8.53
MH100	100W Metal Halide	8.8	8.53
Major road - standard			
S150	150W Sodium	12.4	12.01
MH150	150W Metal Halide	12.4	12.01
S250	250W Sodium	12.8	12.34
MH250	250W Metal Halide	12.8	12.34
S400	400W Sodium	12.8	12.39
Minor road - fully cut off (low glare)			
M80	80W Mercury	10.5	10.13
Major road - fully cut off (low glare)			
S150	150W Sodium	14.9	14.43
MH150	150W Metal Halide	14.9	14.43
S250	250W Sodium (inc. PECB)	11.3	10.90
S250	250W Sodium (w/o PECB)	16.0	15.46
MH250	250W Metal Halide	16.0	15.46
S400	400W Sodium	15.0	14.48
MH400	400W Metal Halide	15.0	14.48
Post top - standard			
M80	80W Mercury	13.0	12.55
Floodlight			
S250	250W Sodium	20.5	19.76
MH250	250W Metal Halide	20.5	19.76
S400	400W Sodium	21.3	20.53
MH400	400W Metal Halide	21.3	20.53
Brackets			
Bracket - minor		2.5	2.39
Bracket - major		15.0	14.44
Outreach			
Outreach - minor		3.1	3.01
Outreach - major		6.2	6.01
Pole (wood)			
Pole (wood) - minor		31.0	29.97
Pole (wood) - major		31.0	29.97
Column (steel)			
Column (steel) - minor		76.2	73.53
Column (steel) - major		190.1	183.50

Appendix T: EnergyAustralia pricing

EnergyAustralia

Attachment III.4A

EnergyAustralia's Transmission Pricing Methodology

January 2009

Document Version Control

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CONTROLLED DOCUMENT
Revised Regulatory Proposal January 2009
E Fagan **Executive General Manager (Acting) System Planning & Regulation**
Date: 14 January 2009

EnergyAustralia's Transmission Pricing Methodology

1 July 2009 to 30 June 2014

Table of Contents

1 Introduction

EnergyAustralia provides both transmission and distribution services to a defined geographic area within NSW. This document outlines EnergyAustralia's proposed transmission *pricing methodology*, and is separate to the pricing proposal required to be submitted to the AER for distribution pricing under Chapter 11 and Appendix 1 to the National Electricity Rules (the transitional rules).

This pricing methodology directly reflects the *pricing principles for prescribed transmission services* set out in clause 6A.23 of the National Electricity Rules. This standardised approach has been developed to conform with the steps and sequence set out in the Rules. EnergyAustralia has not proposed any alternative arrangements for its transmission *pricing methodology*.

This pricing methodology is to apply from 1 July 2009 to 30 June 2014.

1.1 *Interpretation*

All terms in this proposed *transmission pricing methodology* that are italicised have the meaning given to them in the *transmission pricing methodology guidelines* or, where no definition is provided in that document, *the Rules*.

A reference to *the Rules* is taken to be a reference to the current version of the National Electricity Rules.

1.2 *Prescribed Transmission Services*

EnergyAustralia's proposed *transmission pricing methodology* relates to the provision of *prescribed transmission services*, referred to as EnergyAustralia prescribed (transmission) standard control services under clause 6.1.6 of the transitional rules. These services include:

- Shared transmission services provided to customers directly connected to the transmission network and connected network service providers (*prescribed TUoS services*);
- Connection services provided to connect EnergyAustralia distribution network to the transmission network (*prescribed exit services*);
- Grandfathered connection services provided to generators and customers directly connected to the transmission network that were in place or committed to be in place on 9 February 2006 (*prescribed entry services* and *prescribed exit services*); and
- Services required under *the Rules* or in accordance with jurisdictional electricity legislation that are necessary to ensure the integrity of the transmission network, including through the maintenance of power system security and assisting in the planning of the power system (*prescribed common transmission services*).

This proposed transmission *pricing methodology* does not relate to the provision of *negotiated transmission services* (referred to as negotiated distribution services under clause 6.1.6 of the transitional rules) provided by EnergyAustralia.

1.3 *Rules Requirement*

Clause 6A.24.1 of *the Rules* states that the *transmission pricing methodology* is a methodology, formula, process or approach that when applied by a TNSP:

(1) allocates the aggregate annual revenue requirement (AARR) for prescribed transmission services to:

  (i) the *categories of prescribed transmission services* for that provider; and

(ii) *transmission network connection points* of *Transmission Network Users*; and

(2) determines the structure of the prices that a *Transmission Network Service Provider* may charge for each of the *categories of prescribed transmission services* for that provider.

The Rules also require that the *transmission pricing methodology* satisfy principles and guidelines established by *the Rules*. In particular, clause 6A.10.1(e) of *the Rules* requires that the proposed *transmission pricing methodology* must:

(1) give effect to and be consistent with the *Pricing Principles for Prescribed Transmission Services* (that is to say, the principles set out in rule 6A.23); and

(2) comply with the requirements of, and contain or be accompanied by such information as is required by, the *transmission pricing methodology guidelines* made for that purpose under rule 6A.25.

2 Transmission Pricing Methodology Guideline Requirements

2.1 *Co-ordinating Network Service Provider*

In accordance with clause 6A.29.1 of *the Rules*, TransGrid is the *Co-ordinating Network Service Provider* for NSW. As at May 2008, for the purposes of transmission pricing there are four TNSPs in NSW. EnergyAustralia is required to annually provide TransGrid with a revised model of EnergyAustralia's transmission network, with the approved AARR for its *transmission system* already allocated in accordance with this transmission pricing proposal. EnergyAustralia is also required to provide any other information reasonably required by TransGrid to ensure the proper calculation of prescribed transmission prices in New South Wales. Note also that:

- the calculation of the postage stamp rates which form part of transmission prices referred to in the AER Guidelines at 2.1(h); and
- prudent discounts referred to in the AER Guidelines at 2.1(k) are also calculated as part of the postage stamp allocation;

are calculated by the coordinating TNSP, TransGrid.

2.2 *Summary of Proposal*

The AER's transmission *pricing methodology guidelines* supplement and elaborate on the pricing principles contained in Chapter 6A of *the Rules* in so far as they specify or clarify:

- the information that is to accompany a proposed transmission *pricing methodology*;
- permitted pricing structures for the recovery of the locational component of providing *prescribed TUoS services*;
- permitted postage stamp pricing structures for *prescribed common transmission services* and the recovery of the adjusted non-locational component of providing *prescribed TUoS services*;
- the types of *transmission system* assets that are *directly attributable* to each category of *prescribed transmission services*; and
- those parts of a proposed *transmission pricing methodology*, or the information accompanying it that will not be publicly disclosed without the consent of the TNSP.

As EnergyAustralia is an *appointing provider* of transmission services in NSW, this transmission *pricing methodology* is limited to:

- Calculation of the Annual Aggregate Revenue Requirement for each year of the regulatory control period;
- Proposing a methodology to determine whether assets fall in to the categories of exit, entry, shared or common service;
- Allocating the AARR to those asset classes of exit, entry, shared and common service, using an attributable cost share method, to determine an Annual Service Revenue Requirement (ASRR) for each asset class;
- Allocating the ASRR of each asset class to the specific assets within that asset class;
- Detailing the methodology for implementation of the priority ordering approach under clause 6A.23.2(d) of the Rules including two worked examples;
- Billing arrangements for a small number of direct connected transmission customers
- Management of prudential requirements and prudent discounts for new or existing connections to the EnergyAustralia transmission network;
- Describing how asset costs which are associated with prescribed entry services and prescribed exit services at a connection point, which may be attributable to multiple transmission network users, will be allocated; and
- Detail how EnergyAustralia intends to monitor and develop records of its compliance with its approved transmission *pricing methodology*, the pricing principles for *prescribed transmission services* (clause 6A.23) and part J of *the Rules* in general.

Elements of a *pricing methodology* that are required as part of the AER guidelines and National Electricity Rules that are carried out by TransGrid on behalf of EnergyAustralia are:

- any adjustments required to be made to the locational component of the ASRR as required in the Rules[1].
- any adjustments required to be made to the pre-adjusted non-locational component of the ASRR as required in the Rules[2].
- allocation of the locational component of prescribed TUoS services to transmission connection points.
- establishing structure and price for common service, general, and locational charges at each of EnergyAustralia's transmission connection points[3].

3 Proposed Transmission Pricing Methodology

3.1 *Transitional Arrangements applicable to EnergyAustralia for the 2009-14 Regulatory Period*

Chapter 11 of the *Rules* provides Transitional Rules in relation to the economic regulations of distribution services in NSW and the ACT for the 2009-14 regulatory period. Clause 6.1.6 of the Transitional Rules applies the pricing rules in Part J of Chapter 6 to EnergyAustralia's prescribed

---

[1] Rules, clause 6A.23(c)(1)

[2] Rules, clause 6A.23(c)(2)

[3] That is, EnergyAustralia transmission connection points that supply EnergyAustralia's distribution network, not to be confused with TransGrid connection points that supply EnergyAustralia's distribution network.

(transmission) standard control services. This clause further provides that Part J applies as if reference to "prescribed distribution services" were references to EnergyAustralia prescribed (transmission) standard control services and the reference in clause 6A.22.1 to clause 6A.3.2 were a reference to rules 6.6 and 6.13.

Clause 6.8.2(c)(9) of the Transitional Rules requires EnergyAustralia to submit a proposed pricing methodology to the Australian Energy Regulator (AER) as part of its regulatory proposal submitted to the AER.

3.2 *Aggregate Annual Revenue Requirement*

The Aggregate Annual Revenue Requirement (AARR) is calculated in accordance with clause 6A.22.1 of *the Rules* as:

> "the *maximum allowed revenue* referred to in clause 6A.3.1 adjusted:
>
> (1) in accordance with clause 6A.3.2, and
>
> (2) by subtracting the operating and maintenance costs expected to be incurred in the provision of *prescribed common transmission services*."

Clause 6A.3.1 in turn operates so that the revenue that may be earned in any regulatory year of a regulatory control period from the provision of EnergyAustralia prescribed (transmission) services is the maximum allowed revenue subject to any adjustments referred to in clause 6.6 and 6.13 of the Transitional Rules and is to be determined in accordance with the applicable determination.

The portion of the annual revenue requirement relevant to prescribed (transmission) standard control services under transitional clause 6.12.1A(a)(1) is used to establish a Maximum Allowed Revenue consistent with Transitional Rule 6.2.5(c1)(3). To arrive at the AARR for the purposes of Part J of Chapter 6A, the Maximum Allowed Revenue is adjusted in accordance with:

> (1) Rules 6.6. (relating to adjustments after the making of a building block determination); and
>
> (2) Rule 6.13 (relating to revocation); and
>
> (3) Subtracting the operating and maintenance costs expected to be incurred in the provision of *prescribed common transmission services*.

The costs referred in (3) above are derived from budget projections and include:

- network switching and operations;
- administration and management of the business;
- network planning and development; and
- general overheads.

3.3 *Categories of Service*

EnergyAustralia's AARR is recovered from transmission charges for the following categories of transmission service:

- *Prescribed exit services* which include assets that are fully dedicated to serving a Transmission Customer or group of Transmission Customers at a single connection point and: (a) are deemed prescribed by virtue of the operation of clause 11.6.11 of *the Rules*; or (b) are provided to Network Service Providers at the boundary of the prescribed transmission network;

- *Prescribed transmission use of system (TUoS) services* which include assets that are shared to a greater or lesser extent by all users across the *transmission system* and are not *prescribed common transmission services, prescribed entry services* or *prescribed exit services*; and
- *Prescribed common transmission services*, which are services that benefit all Transmission Customers and cannot be reasonably allocated on a locational basis.

EnergyAustralia does not currently have any assets providing entry services to a generator. However, this proposal outlines EnergyAustralia's proposed methodology with respect to the allocation of these services in anticipation of this service being required. *Prescribed entry services* include assets that are fully dedicated to serving a Generator or group of Generators at a single connection point.

3.4 *Cost Allocation*

The first step in calculating prescribed transmission service prices is to classify each asset utilised in the provision of *prescribed transmission services* into one of the above categories of service. The delineation between the assets that provide *prescribed entry services, prescribed exit services, prescribed TUoS services* and *prescribed common transmission services* is set out in clause 2.4 of the *transmission pricing methodology guidelines.*

The cost allocation process assigns the optimised replacement cost (ORC)[4] of all prescribed assets to either *prescribed common transmission services* (assets that benefit all transmission customers) or individual network branches (transmission lines and transformers). Each branch is then defined as entry, exit or shared network. This process of cost allocation is explained in more detail in Appendix A.

3.5 *Calculation of the attributable cost share for each category of service*

The second step in calculating prescribed transmission service prices is the calculation of the attributable cost shares. The attributable cost share for each category of service is calculated in accordance with clause 6A.22.3 of *the Rules* as the ratio of:

- the costs of the *transmission system* assets *directly attributable* to the provision of that category of *prescribed transmission services* (as determined in 6.5 above); to
- the total costs of all the TNSP's *transmission system* assets *directly attributable* to the provision of *prescribed transmission services* (as determined in 6.5 above).

For example, if the ORCs of prescribed services assets have been allocated to the applicable categories of *prescribed transmission services* as shown in Table 1 then the attributable costs shares are calculated as:

$$\text{Attributable Cost Share}_{EXIT} = ORC_{EXIT} / ORC_{TOTAL}$$
$$= \$6,972,222 / \$43,050,000$$
$$= 0.162$$

with the attributable cost shares of the other categories calculated in the same manner as shown in

Table 2.

[4] Consistent with clause 6A.22.3(b) of the Rules

Table 1: Costs allocated to categories of prescribed transmission services

Category	ORC
Exit service	6,972,222
Entry service	1,761,111
TUoS service	33,566,667
Common Service	750,000
Total	43,050,000

Table 2: Attributable Cost Shares

Category	ORC	Attributable Cost Share
Exit service	6,972,222	0.162
Entry service	1,761,111	0.041
TUoS service	33,566,667	0.780
Common Service	750,000	0.017
Total	43,050,000	1.000

3.6 *Calculation of the Annual Service Revenue Requirement (ASRR)*

The third step in calculating prescribed transmission service prices is to allocate the AARR to each category of prescribed transmission service in accordance with the attributable cost share for each such category of services.

This allocation results in the annual service revenue requirement (ASRR) for that category of services.

Assuming an AARR of $2,504,434 and applying the attributable cost shares determined above the ASRR for each category of prescribed services is calculated as:

$$ASRR_{EXIT} = AARR \times \text{Attributable Cost Share}_{EXIT}$$
$$= \$2{,}504{,}434 \times 0.162$$
$$= \$405{,}609$$

with the ASRRs of the other categories calculated in the same manner.

Table 3 Annual Service Revenue Requirements

Category	Attributable Cost Share	Annual Service Revenue Requirement (ASRR)
Exit Service	0.162	405,609
Entry Service	0.041	102,453
TUoS Service	0.780	1,952,741
Common Service	0.017	43,631
Total	1.000	2,504,434

3.7 *Allocation of the ASRR to transmission network connection points*

The fourth step in calculating prescribed transmission service prices is to allocate the ASRR for *prescribed entry services*, *prescribed exit services* and *prescribed TUoS services* to each transmission network connection point in accordance with the principles of clause 6A.23.3 of *the Rules*.

3.7.1 Prescribed entry services

The whole of the ASRR for *prescribed entry services* is allocated to transmission network connection points in accordance with the attributable connection point cost share for *prescribed entry services* that are provided by the TNSP at that connection point.

The attributable connection point cost share for *prescribed entry services* is the ratio of the costs of the *transmission system* assets *directly attributable* to the provision of *prescribed entry services* at that transmission network connection point to the total costs of all the TNSP's *transmission system* assets *directly attributable* to the provision of *prescribed entry services*.

For example, consider two generators, Gen A1 and Gen A2 that receive *prescribed entry services* and the cost allocation methodology has allocated the ORCs of assets *directly attributable* to entry services to them as shown in

Table 4:

$$\text{Attributable Connection Point Cost Share}_{\text{GEN A1}} = \text{ORC}_{\text{GEN A1}} / \text{ORC}_{\text{ENTRY}}$$
$$= \$1,033,333 / \$1,761,111$$
$$= 0.587$$

The attributable connection point cost shares of the other generator is calculated in the same manner as shown in Table 5

Table 4: Prescribed entry services ORCs

Entry	ORC
Gen A1	1,033,333
Gen A2	727,778
Total ORC of prescribed entry assets	1,761,111

Table 5: Attributable connection point cost shares

Entry	ORC	Attributable connection point cost share
Gen A1	1,033,333	0.587
Gen A2	727,778	0.413
Total	1,761,111	1.000

The ASRR allocated to the Gen A1 transmission network connection point is calculated as follows:

$$\text{ASRR}_{\text{GEN A1}} = \text{ASRR}_{\text{ENTRY}} \times \text{Attributable connection point cost share}_{\text{GEN A1}}$$
$$= \$102,453 \times 0.587$$

= $60,114

The ASRR of the other generator connection points is calculated in the same manner.

Table 6: Connection point ASRRs (Entry)

Entry	ORC	Attributable connection point cost share	Connection point ASRR
Gen A1	1,033,333	0.587	60,114
Gen A2	727,778	0.413	42,338
Total	1,761,111	1.000	102,453

The ASRR related to the entry assets for each generator is recovered via a daily fixed charge. For example GEN A1 will be charged a daily rate of:

GEN A1 Fixed Charge = $60,144/365 days[5]
= $226.96/ day for the relevant financial year

No other charges will be applied to generators, as the transmission network is built for load, rather than generation. Common services and TUoS services are therefore allocated to loads.

3.7.2 Prescribed exit services

The whole of the ASRR for *prescribed exit services* is allocated to transmission network connection points in accordance with the attributable connection point cost share for *prescribed exit services* that are provided by the TNSP at that connection point.

The attributable connection point cost share for *prescribed exit services* is the ratio of the costs of the *transmission system* assets *directly attributable* to the provision of *prescribed exit services* at that transmission network connection point to the total costs of all the *transmission system* assets *directly attributable* to the provision of *prescribed exit services.*

The ASRRs of the prescribed exit connection points are calculated in the same manner as for the entry connection points.

Table 7: Connection point ASRRs (Exit)

Exit	*ORC*	*Attributable connection point cost share*	*Connection point ASRR*
Load A1	2,083,333	0.299	121,198
Load A2	1,405,556	0.202	81,768
Load B1	2,633,333	0.378	153,194
Load C1	850,000	0.122	49,449
Total	6,972,222	1.000	405,609

The ASRR related to the exit assets for each load is recovered via a daily fixed charge. For example Load A1 will be charged a daily rate of:

Load A1 Fixed Charge = $121,198/365 days[6]

[5] 366 days used for this calculation if a leap year

[6] 366 days used for this calculation if a leap year

= $332.05 per day for the relevant financial year

Locational charges, TUoS general charges and common service charges will also apply to Load A1, and are calculated by TransGrid as the Co-ordinating TNSP appointed by EnergyAustralia.

3.7.3 Prescribed Transmission Use of System (TUoS) services

The prescribed TUoS (shared network) services ASRR is recovered from:

- *Prescribed TUoS services* (locational component); and
- *Prescribed TUoS services* (the adjusted non-locational component).

Clause 6A.23.3(c)(1) of *the Rules* requires that:

> "a share of the ASRR (the locational component) is to be adjusted by subtracting the estimated *auction amounts* expected to be distributed to the TNSP under clause 3.18.4 from the *connection points* for each relevant *directional interconnector* and this adjusted share is to be allocated as between such *connection points* on the basis of the estimated proportionate use of the relevant *transmission system* assets by each of those customers, and the *CRNP methodology* and *modified CRNP methodology* represent two permitted means of estimating proportionate use".

In NSW, compliance with this clause is carried out by TransGrid as the co-ordinating TNSP as EnergyAustralia is not a direct recipient of auction amounts. TransGrid makes relevant adjustments to account for auction amounts in it's pricing methodology consistent with clause 6A.23.3(c)(1). Please refer to TransGrid's *transmission pricing methodology* with respect to compliance with this clause.

Allocation of the locational component of prescribed TUoS services is carried out by TransGrid using the CRNP methodology, which assigns a proportion of shared network costs to individual customer connection points. TransGrid does this using the TPRICE *Cost Reflective Network Pricing* software used by most TNSPs in the NEM. Details on this calculation can be found in TransGrid's *transmission pricing proposal*.

The CRNP methodology requires three sets of input data:

- An electrical (loadflow) model of the network;
- A cost model of the network (the results of the cost allocation process described in Appendix A); and
- An appropriate set of load/generation patterns.

The remainder of the ASRR (the pre-adjusted non-locational component) is to be adjusted:

- by subtracting the amount (if any) referred to in clause 6A.23.3(e) of *the Rules*;
- by subtracting or adding any remaining settlements residue (not being settlements residue referred to in the determination of the locational component but including the portion of settlements residue due to intra-regional loss factors) which is expected to be distributed or recovered (as the case may be) to or from the TNSP in accordance with clause 3.6.5(a) of *the Rules*;
- for any over-recovery amount or under-recovery amount from previous years;
- for any amount arising as a result of the application of clause 6A.23.4(h) and (i) of *the Rules*; and
- for any amount arising as a result of the application of prudent discounts in accordance with clause 6A.26.1(d)-(g) of *the Rules*

These adjustments are carried out by TransGrid as the Co-ordinating TNSP in NSW. EnergyAustralia provides advice to TransGrid of any expected under-recovery or over-recovery amount from previous years to be used by TransGrid in setting prices each year.

3.7.4 Costs that could be allocated to more than one category of service

EnergyAustralia allocates substation costs that are *directly attributable* to entry, exit, common and TUoS services and then allocates the residual costs, known as substation local costs, to entry, exit and TUoS services on the basis of the number of pricing branches (transmission lines and transformers) connected to that substation.

Clause 6A.23.2(d) of *the Rules* has a priority ordering concept for the allocation of those costs which could be attributable to more than one category of *prescribed transmission services*.

The substation local costs are allocated to the various prescribed services in accordance with the provisions of clause 6A.23.2(d) of *the Rules* having regard to the stand alone costs associated with the provision of *prescribed TUoS services* and *prescribed common transmission services* with the remainder being allocated to *prescribed entry and prescribed exit services*.

Details on EnergyAustralia's application of priority ordering can be found in Appendix A.

3.8 *Provision for relaxation of TUoS locational side constraints*

The implementation of clause 6A.23.4(g)of *the Rules* allows for the relaxation of the 2% side constraint for material changes in connection point load or renegotiation of connection agreements, subject to AER approval.

In the event that a Transmission Customer requests a material increase in demand at an existing connection point, EnergyAustralia, together with TransGrid, as the Co-ordinating TNSP in NSW will seek approval from the AER to set the prescribed TUoS – locational price as intended by clause 6A.23.4(g) of *the Rules*.

3.9 *Transmission Prices and Charges*

Calculation of prices for all prescribed transmission services in NSW is carried out by TransGrid as the Co-ordinating TNSP in NSW. Please refer to TransGrid's pricing methodology for the calculation of prices for EnergyAustralia's transmission network. TransGrid receives EnergyAustralia's transmission models with all assets allocated to the relevant asset classes and a portion of the AARR allocated to give the ASRR for each class. Assets within each asset class have already been allocated a portion of the ASRR for that class in accordance with this pricing methodology.

3.10 *Contract Demand Charge*

EnergyAustralia is able to propose locations on its transmission network where an excess demand charge is to apply. EnergyAustralia nominates to TransGrid the particular location of one of EnergyAustralia's transmission connections points (whether that is a connection point direct to TransGrid or one that connects EnergyAustralia's distribution network to it's transmission network) where excess demand charging is to apply. EnergyAustralia also proposes an agreed maximum demand for this connection point. If EnergyAustralia's maximum demand exceeds the *contract agreed maximum demand* level at any time during the financial year then an Excess Demand Charge applies.

TransGrid determines the rates for the Contract Demand Charge as the co-ordinating TNSP in NSW. Details on the contract maximum demand charge can be found in TransGrid's *transmission pricing methodology*

3.11 *Setting of TUoS Locational Prices between Annual Price Publications*

In the event that EnergyAustralia requires a TUoS locational price at a new connection point or at a connection where the load has changed significantly after prescribed TUoS service locational prices have been determined and published, an interim price, not subject to the side constraints of clause 6A.23.4(f) of *the Rules*, will be determined by TransGrid as the co-ordinating TNSP in NSW. This will be calculated using the prevailing pricing models with demands estimated in a manner consistent with clause 2.2(f) of the *transmission pricing methodology guidelines*.

A price subject to the side constraints of clause 6A.23.4(f) of *the Rules* will be determined and published at the next annual price determination.

4 Billing Arrangements

4.1 *Billing for prescribed transmission services*

Consistent with the clause 6A.27.1 of *the Rules,* EnergyAustralia will calculate the transmission service charges payable by *Transmission Network Users* connected to the EnergyAustralia transmission network, in accordance with the transmission service prices published under clause 6A.24.2 as calculated by TransGrid. The prices calculated by TransGrid that are relevant to the EnergyAustralia transmission network are published on the EnergyAustralia website.

Where charges are determined for *prescribed transmission services* from metering data, these charges will be based on kW or kWh obtained from the metering data managed by NEMMCO.

EnergyAustralia will issue bills to *Transmission Network Users for prescribed transmission services* which satisfy or exceed the minimum information requirements specified in clause 27.2 of *the Rules* on a monthly basis or as agreed between the parties.

Consistent with clause 6A.27.3 of *the Rules*, a *Transmission Network User* must pay charges for *prescribed transmission services* properly charged to it and billed in accordance with the *transmission pricing methodology* of the relevant *Transmission Network Service Provider* by the date specified on the bill. For the avoidance of doubt, EnergyAustralia's transmission connected customers bills are sent to their retailer, rather than to the customer directly.

4.2 *Payments between Transmission Network Service Providers*

Consistent with clause 6A.27.4 of *the Rules,* TransGrid is the *Co-ordinating Network Service Provider* in NSW under 6A.29.1 of *the Rules* and will pay to each other relevant *Transmission Network Service Provider* the revenue which is estimated to be collected during the following year by the first provider as charges for *prescribed transmission services* for the use of transmission systems owned by those other *Transmission Network Service Providers.*

Such payments will be determined by TransGrid as the *Co-ordinating network service provider* for the region.

Financial transfers payable under clause 6A.27.4 of *the Rules* will be paid in equal monthly instalments or as documented in revenue collection agreements negotiated between the parties.

5 Prudential Requirements

5.1 *Prudential Requirements for prescribed transmission services*

Consistent with clause 6A.28.1 of *the Rules*, EnergyAustralia may require a *Transmission Network User* to establish prudential requirements for either or both connection services and transmission use of system services. These prudential requirements may take the form of, but need not be limited to, capital contributions, pre-payments or financial guarantees.

The requirements for such prudential requirements will be negotiated between the parties and specified in the applicable connection agreement.

5.2 *Capital contribution or prepayment for a specific asset*

Consistent with clause 6A.28.2 of *the Rules*, where EnergyAustralia is required to construct or acquire specific assets to provide prescribed connection services or *prescribed TUoS services* to a *Transmission Network User*, EnergyAustralia may require that user to make a capital contribution or prepayment for all or part of the cost of the new assets installed.

In the unlikely event that a capital contribution is required, any contribution made will be taken into account in the determination of prescribed transmission service prices applicable to that user by way of a proportionate reduction in the ORC of the asset(s) used for the allocation of prescribed charges or as negotiated between the parties.

In the event that a prepayment is required any prepayment made will be taken into account in the determination of prescribed transmission service prices applicable to that user in a manner to be negotiated between the parties.

The treatment of such capital contribution or prepayments for the purposes of a revenue determination will in all cases be in accordance with the relevant provisions of *the Rules*.

EnergyAustralia may require a bank guarantee from a transmission customer, to cover the financial year of a transmission investment made by EnergyAustralia for the customer. Bank guarantees will only be relevant in cases where such investments relate to the construction of prescribed transmission assets. Such guarantees will be made in agreement with the customer and hold funds as security for EnergyAustralia in the event that the customer does not provide a satisfactory income stream through payment for TUoS charges over an agreed period of time.

6 Prudent Discounts

EnergyAustralia is required to provide information to TransGrid in relation to prudent discounts relating to EnergyAustralia's transmission customers. TransGrid adjusts, in accordance with rule 6A.26.1(d)-(g), the non-locational component of the ASRR for *prescribed TUoS services* for the amount of any anticipated under-recovery arising from prudent discounts applied. Refer to TransGrid's *transmission pricing methodology* with respect to the calculation of the adjustments and then application of those adjustments under 6A.26.1(d)-(g), as TransGrid is the *Co-ordinating TNSP* for NSW. The calculation of the discount amount is carried out as the difference between the revenue earned with the discounted prices compared to the revenues earned if the maximum allowed prices had been applied, consistent with the *Rules*[7]. This amount is provided by EnergyAustralia to TransGrid as part of the annual pricing

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[7] Rules, clause 6A.26.1(d)

process. EnergyAustralia has a prudent discount arrangement with one transmission customer, details of which are attached as a separate confidential document as part of this *pricing methodology.*

7 Monitoring and Compliance

As a regulated business EnergyAustralia is required to maintain extensive compliance monitoring and reporting systems to ensure compliance with its Transmission and Distribution Licence, Revenue Determination, the *National Electricity Rules* together with other legislative obligations.

In order to monitor and maintain records of its compliance with its approved *transmission pricing methodology*, the pricing principles for *prescribed transmission services*, and part J of *the Rules* EnergyAustralia proposes to:

- Maintain the specific obligations arising from part J of *the Rules* in its compliance management system;
- Maintain electronic records of the annual calculation of prescribed transmission prices and supporting information; and
- Periodically subject its transmission pricing models and processes to functional audit by suitably qualified persons.

8 Additional information requirements

EnergyAustralia does not consider transitional arrangements necessary as a result of the implementation of this proposed *transmission pricing methodology*. EnergyAustralia does not have any relevant derogations in accordance with chapter 9 of *the Rules,* nor are there any applicable transitional arrangements arising from chapter 11 of *the Rules* relevant to this proposed *transmission pricing methodology.*

9 Confidential Elements of Pricing Methodology

EnergyAustralia has provided details of a prudent discount to one of its transmission customers, as an appendix to this pricing methodology. EnergyAustralia has also provided a non-confidential version of this pricing methodology to the AER for publication. EnergyAustralia requests that this confidential version of EnergyAustralia's pricing methodology be kept confidential,. as this information is of a commercially sensitive nature to the customer. The remainder of this *pricing methodology* is not considered confidential by EnergyAustralia.

Appendix A: Details of Cost Allocation Process

A detailed cost allocation process is used to assign the optimised replacement cost (ORC) of all prescribed service assets to either common service (assets that benefit all transmission customers), network branches (transmission lines or transformers) and *prescribed entry or prescribed exit services* in a manner consistent with Section 2.4 of the transmission *pricing methodology guidelines*.

The cost allocation process is summarised as follows:

Step 1: Initial Asset Cost Allocation

Assets and their ORCs are assigned to one of the following primary asset categories:

- transmission lines;
- transformers;
- circuit breakers;
- common service assets (communications, reactive support, office buildings etc.); and
- substation local assets (ancillary equipment, civil work, and establishment).
- The following plant items are not separately identified in ORC values and are incorporated into the ORC of the associated primary items above:
- Bus work;
- Secondary systems including protection and instrument transformers.

Step 2: Allocation to Classes of Service

Assets are allocated to the classes of prescribed service in accordance with the provisions of Section 2.4 of the *transmission pricing methodology guidelines*. In the case of circuit breakers, each circuit breaker has its replacement cost divided evenly between the branches to which it is *directly attributable*. Any circuit breaker that is not *directly attributable* to any branch together with substation local costs identified in step 1 become subject to the priority ordering process.

In the case of a connection asset attributable to multiple network users, such as a transformer, serving multiple transmission customers at a connection point (which may provide *prescribed entry* and/or *prescribed exit services)* the cost of the shared connection asset will be allocated between the network users in accordance with a demand related allocation or as negotiated between the connected parties.

Step 3: Priority Ordering

In the case of those costs which would be attributable to more than one category of *prescribed transmission services*, specifically the substation local assets identified in Step 1 and those circuit breakers identified as substation local costs in Step 2, costs will be allocated in accordance with the provisions of clause 6A.23.2(d) of *the Rules* having regard to the stand alone costs associated with the provision of *prescribed TUoS services* and *prescribed common transmission services* with the remainder being allocated to *prescribed entry and prescribed exit services*. The implementation of the priority ordering process is detailed below.

Priority Ordering Methodology

Rules Requirement

Clause 6A.23.2(d) of *the Rules* requires that:

> Where, as a result of the application of the *attributable cost share*, a portion of the *AARR* would be attributable to more than one category of *prescribed transmission services*, that *attributable cost share* is to be adjusted and applied such that any costs of a *transmission system* asset that would

otherwise be attributed to the provision of more than one category of *prescribed transmission services*, is allocated as follows:

1. to the provision of *prescribed TUoS services*, but only to the extent of the *stand-alone amount* for that *category of prescribed transmission services*;
2. if any portion of the costs of a *transmission system* asset is not allocated to *prescribed TUoS services*, under subparagraph (1), that portion is to be allocated to *prescribed common transmission services*, but only to the extent of the *stand-alone amount* for that *category of prescribed transmission services*;
3. if any portion of the costs of a *transmission system* asset is not attributed to *prescribed transmission services* under subparagraphs (1) and (2), that portion is to be attributed to *prescribed entry services* and *prescribed exit services*.

Stand-alone amount is defined as:

> For a *category of prescribed transmission services*, the costs of a *transmission system* asset that would have been incurred had that *transmission system* asset been developed, exclusively to provide that *category of prescribed transmission services*.

AEMC Rule determination

In its rule determination the AEMC provided the following guidance on the application of the priority ordering approach for the allocation of costs which can be attributed to more than one type of service[8]:

> "The Commission has maintained a priority ordering approach for the allocation of expenses or costs which can be attributed to more than one type of service. The cascading principle adopted by the Commission is based on the premise that users are seen to be the 'cause' of transmission investment. Therefore, costs should be first allocated to prescribed transmission use of system services on a stand-alone basis and then to *prescribed common transmission services*. Where a service/cost cannot justifiably be attributed to TUoS or common services it should be allocated to entry and exit services."

In developing this methodology, EnergyAustralia has had regard for the following example in the rule determination[9]:

Consider a substation costing $30 million that was developed:

- partly in order to provide *Prescribed TUoS services*;
- partly in order to provide *Prescribed common transmission services*; and
- partly in order to provide *prescribed exit services*.

Then assume that had the substation been developed solely to provide *prescribed TUoS services*, it could have been much smaller and would have cost only $10 million. Had the substation been developed solely in order to provide *prescribed common transmission services*, it would have cost $5 million. Finally, had the substation been developed solely in order to provide *prescribed exit services*, it would have cost $20 million.

The application of the principle would then lead to the $30 million cost of the substation being attributed to Prescribed Transmission Service categories as follows:

- $10m to the *prescribed TUoS services* ASRR;

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[8] Rule Determination for National Electricity Amendment (Pricing of *Prescribed Transmission Services*) Rule 2006, p5
[9] Ibid p37

- $5m to the *prescribed common services* ASRR; and
- the remaining $15 million to the prescribed exit service ASRR.

Objective and General Approach

The proposed allocation methodology relies on the assumption that substation infrastructure and establishment costs are proportionate to the number of high voltage circuit breakers in the substation.

Based on this assumption, the appropriate allocator for substation infrastructure and establishment costs for a stand-alone arrangement is the ratio of the number of high voltage circuit breakers in the stand-alone arrangement to the number of high voltage circuit breakers in the whole substation.

Step 1: Branch Identification

Identify the branches, being the lines, transformers, major reactive devices and exits/entries in the substation which provide prescribed TUoS, *prescribed common transmission services* and exit or entry services, in the substation.

Step 2: Allocation of Circuit Breakers to Branches

For each high voltage circuit breaker in the substation identify the branches directly connected to it. Any circuit breaker that does not directly connect to a branch is excluded from allocation and all costs associated with it are added to the substation infrastructure and establishment cost.

Count the total number of circuit breakers directly connected to branches.

As a general rule, Distribution Network Service Providers (DNSPs) are classified as a prescribed exit service while Generators are classified as a prescribed entry service. Negotiated services are not part of the regulated asset base and fall outside the priority ordering process detailed in clause 6A.23.2(d) of *the Rules*.

Step 3.1: Stand-alone arrangements for Prescribed TUoS

With reference to the number of lines providing prescribed TUoS services determine the number of circuit breakers required to provide TUoS services of an equivalent standard on a stand-alone basis21. The stand-alone configuration is the simplest substation configuration (in the absence of development) had it been developed to provide a prescribed TUoS service. This may be done by way of a look up of typical stand-alone configurations.

Step 3.2: Stand-alone arrangements for Prescribed common transmission services

With reference to the number of lines providing *prescribed TUoS services* and the devices providing *prescribed common service* determine the number of circuit breakers required to provide *prescribed common transmission services* of an equivalent standard on a stand-alone basis. The stand-alone configuration is the simplest substation configuration (in the absence of development) had it been developed to provide a *prescribed common service*. This may be done by way of a look up of typical stand-alone configurations.

Step 4: Allocation of substation infrastructure and establishment costs

Step 4.1. Allocation of Prescribed TUoS

Allocate a portion of substation infrastructure and establishment costs to prescribed TUoS according to the ratio of the high voltage circuit breakers identified in step 3.1 to the total number of high voltage circuit breakers connected to branches in the substation identified in step 2.

Step 4.2 Calculate the Unallocated Substation Infrastructure Costs after TUoS Allocation

Calculate the Unallocated substation infrastructure cost by subtracting the amount calculated in step 4.1 from the total substation infrastructure amount.

Step 4.3 Allocation of Prescribed Common Service

Allocate a portion of the substation infrastructure and establishment costs to *prescribed common service* based on to the ratio of the high voltage circuit breakers providing *prescribed common transmission services* identified in step 3.2 to the total number of high voltage circuit breakers connected to branches in the substation. If the common service portion of substation infrastructure is greater than the Unallocated costs, then the Unallocated portion only is attributed to *prescribed common service*. In this instance, nothing will be attributed to *prescribed entry and prescribed exit services.*

Step 4.4 Calculate the Unallocated Substation Infrastructure Costs after Common Service Allocation

Calculate the Unallocated substation infrastructure cost by subtracting the amount calculated in step 4.3 from the amount calculated in step 4.2.

Step 4.5 Allocation of Prescribed Entry and Exit Service

Allocate the remaining substation infrastructure and establishment costs (calculated in step 4.4) to each branch providing prescribed exit or entry services based on the ratio of the high voltage circuit breakers providing the entry or exit service to the branch to the total number of high voltage circuit breakers providing entry or exit services or in accordance with the TNSP's cost allocation methodology as appropriate.

Step 4.6 Allocation of Assets that provide both Entry and Exit Services

Clause 2.1(d)(3) of the AER guidelines states that a TNSP must provide:

Details of how the *AARR* will be allocated to derive the *ASRR* for each *category of prescribed transmission service*, including:

> (3) how asset costs which may be attributable to both *prescribed entry services* and *prescribed exit services* will be allocated.

EnergyAustralia proposes that where assets can be defined as both entry and exit services, that the allocation of the remainder of costs (after completing allocation to TUoS and common service) to be allocated on a simple proportion of circuit breakers that immediately connect those customers, for each service against the total number of circuit breakers of entry and exit services combined.

Consider the worked example in Appendix A on p20. Suppose that next to the negotiated service, a generator is connected to the busbar via a single circuit breaker and next to that yet another DNSP exit load connected via a single circuit breaker. In that case, there are now two circuit breakers for DNSP exit loads, and one circuit breaker for generator entry service. In that case, two thirds of the remaining \$1.5M entry/exit service cost will be charged to the exit service and one third to the entry service.

This cost allocation will apply unless negotiated service arrangements apply between the parties, in which case cost the allocation in these particular circumstance will be negotiated between the parties

Step 4.7 Allocation of Exit Assets a Connection Point with Multiple Transmission Customers

Clause 2.1(e)(1)C of the guidelines states that a TNSP must provide:

Details of how the *ASRR* for each *category of prescribed transmission service* will be allocated to each *transmission connection point*, including:

(1) how the *attributable connection point cost share* for both *prescribed entry services* and *prescribed exit services* will be calculated in accordance with clause 6A.22.4 of the *National Electricity Rules*, including:

> c) how asset costs allocated to *prescribed entry services* and *prescribed exit services* at a *connection point*, which may be attributable to multiple *transmission network users*, will be allocated;

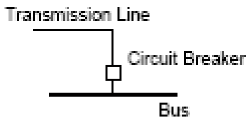
Where exit or entry assets are shared between serveral customers, whether load and/or generation, that the allocation of the remainder of costs (after completing allocation to TUoS and common service) to be allocated on a simple proportion of the circuit breakers that immediately connect that customer to the exit/entry point against the total number of the same circuit breakers. This is the same method as that outlined above at Step 4.6.

Notes

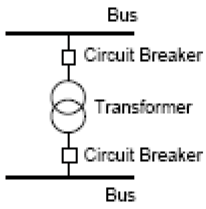
- Costs are only allocated in step 4 until fully allocated.
- Consistent with clause 6A.23(d)(3) of *the Rules* it is possible that no costs will be attributed to entry and exit services.
- New and existing negotiated service assets are excluded from the analysis as any incremental establishment costs associated with them are taken to be included in the negotiated services charges on a causation basis.
- The assessment of standalone arrangements only needs to be conducted once per substation except where changes to the configuration of the substation occur.

Definition - Branches

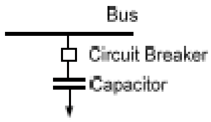
As illustrated by the diagrams below a "Branch" is a collection of assets (e.g. lines, circuit breakers, capacitors, buses and transformers) that provide a transmission service.



Branch with Transmission Line, Bus and Circuit Breaker



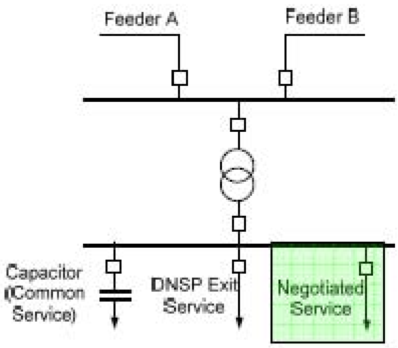
Branch with Transformer, Circuit Breaker and two Busses



Branch with Capacitor, Circuit Breaker and Bus

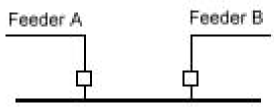
Worked Example 1: Substation Costs Priority Ordering

Consider the substation below with an ORC value of $12M. However $3m is for the existing negotiated service, which does not form part of the regulated asset base and is not governed by 6A.23.2(d). Therefore, the negotiated service does not exist for the purposes of priority ordering, and the total infrastructure cost is $9M for allocation purposes.

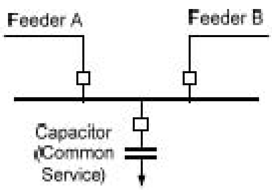


Step 1: The branches are Feeder A, Feeder B, DNSP Exit, Tie Transformer and Capacitor, the negotiated service branch is not considered as discussed above.

Step 2: The total number of circuit breakers directly connected to branches is 6.



Step 3.1: The stand-alone arrangement for the provision of *prescribed TUoS services* to an equivalent standard is shown below and consists of 2 circuit breakers.



Step 3.2: The stand-alone arrangement for the provision of *prescribed common transmission services* to an equivalent standard is shown below and consists of 3 circuit breakers.

Step 4:

Total infrastructure cost is $9M, excluding the negotiated service as discussed.

Costs are allocated to prescribed TUoS in the ratio of the circuit breakers in the stand-alone arrangement to the total circuit breakers.

Infrastructure Cost Allocated to TUoS = (2/6) x $9m = $3m

Unallocated = $9m - $3m = $6m

Costs are allocated to *prescribed common service* in the ratio of the circuit breakers in the stand-alone arrangement to the total circuit breakers.

Infrastructure Cost allocated to Common Service = (3/6) x $9m = $4.5m

Unallocated = $6m - $4.5m = $1.5m

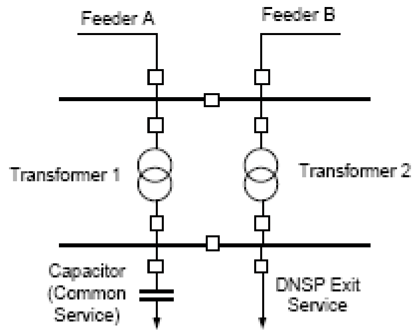
Remainder of Unallocated (calculated above) to be allocated to *prescribed entry and prescribed exit services*.

Infrastructure Cost allocated to Exit = $1.5m

Asset Class	Breakers	Allocation	Unallocated
Substation Infrastructure Costs		$9M	$9M
Total Breakers	6		
TUoS Stand Alone Breakers	2		
1. Share to TUoS	=2/6	= 2/6 x $9M = $3M	$6M
Common Service Stand Alone Breakers	3		
2. Share to Common Service	=3/6	= 3/6 x $9M = $4.5M	$1.5M
3. Share to Entry and Exit Services		= $1.5M	

Worked Example 2: Substation Cost Priority Ordering

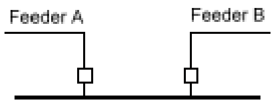
Consider the substation below:



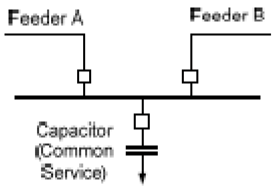
Step 1: The branches are Feeder A, Feeder B, DNSP Exit, Transformer 1, Transformer 2 and Capacitor.

Step 2: The total number of circuit breakers directly connected to branches is 8. The bus section breakers are not directly connected to any of the branches and are therefore ignored for the purposes of priority ordering.

Step 3.1: The stand-alone arrangement for the provision of *prescribed TUoS services* to an equivalent standard is shown below and consists of 2 circuit breakers. Note the bus section breaker is ignored since it is not connected to any of the branches



Step 3.2: The stand-alone arrangement for the provision of *prescribed common transmission services* to an equivalent standard is shown below and consists of 3 circuit breakers.



Step 4:

Assume the total infrastructure cost is $9M.

Costs are allocated to prescribed TUoS in the ratio of the circuit breakers in the stand-alone arrangement to the total circuit breakers.

Infrastructure Cost Allocated to TUoS = (2/8) x $9M = $2.25M

Unallocated = $9M - $2.25M = $6.75M

Costs are allocated to *prescribed common service* in the ratio of the circuit breakers in the stand-alone arrangement to the total circuit breakers.

Infrastructure Cost allocated to Common Service = (3/8) x $9M = $3.375M

Unallocated = $6.75M - $3.375M = $3.375M

Remainder of Unallocated (calculated above) to be allocated to *prescribed entry and prescribed exit services*.

Infrastructure Cost allocated to Exit = $3.375M

Asset Class	Breakers	Allocation	Unallocated
Substation Infrastructure Costs		$9M	$9M
Total Breakers	8		
TUoS Stand Alone Breakers	2		
1. Share to TUoS	=2/8	= 2/8 x $9M = $2.25M	$6.75M
Common Service Stand Alone Breakers	3		
2. Share to Common Service	=3/8	= 3/8 x $9M = $3.375M	$3.375M
3. Share to Entry and Exit Services		= $3.375M	

Appendix B:

Confidential

Appendix U: Submissions

The AER received submissions on the draft decision and on the NSW DNSPs' revised regulatory proposals from the following organisations:

Anglicare Sydney

City of Sydney

Country Energy

EnergyAustralia

Energy Markets Reform Forum

Energy Users Association of Australia

Integral Energy

Origin Energy

Public Interest Advocacy Centre

Total Environment Centre

The AER also received submissions regarding alternative control services in the draft decision (in particular public lighting) from the following organisations:

Ashfield Council

Bankstown City Council

Burwood Council

Cessnock City Council

City of Botany Bay

City of Canterbury

City of Ryde

Hornsby Council

Gosford Council

Hunters Hill Council

Hurstville Council

Ku-ring Gai Council

Lane Cove Council

Marrickville Council

Leichhardt Council

Mosman Council

North Sydney Council

NSROC

SSROC

Sutherland Shire Council

Warringah Council

Waverley Council

Willoughby Council

The Hills Shire Council

Woollahra Municipal Council

On 13 March 2009, the AER released its supplementary draft decision in relation to alternative control (public lighting) services provided by Country Energy, EnergyAustralia, and Integral Energy. The AER received submissions on that supplementary draft decision from the following organisations:

Blacktown City Council

Campbelltown City Council

Country Energy

EnergyAustralia

Hills Council

Integral Energy

Riverina Eastern Regional Organisation of Councils

SSROC (two submissions)

Western Sydney Regional Organisation of Councils

Trans Tasman Energy Group

Appendix V: New information and late submissions received by the AER

In accordance with clause 6.10.3 of the transitional chapter 6 rules, the AER invited DNSPs to submit revised regulatory proposals by 16 January 2009. Clause 6.10.3(b) of the transitional chapter 6 rules provides that a DNSP may only make revisions in its revised regulatory proposal so as to incorporate the substance of any changes required to address matters raised by the draft determination or the AER's reasons for it.

Despite the requirement that revised regulatory proposals respond only to the draft decision, several new matters were raised and new information was provided that did not directly address matters raised by the draft determination or the AER's reasons for it.

Clause 6.10.3(e) of the transitional chapter 6 rules provides that the AER may, but need not, invite written submissions on the revised regulatory proposals. The AER decided to invite submissions on the revised regulatory proposals. In view of the tight timeframe within which to consider any submissions, the AER stated that submissions must be received by 16 February 2009.

Despite the close of submissions on 16 February 2009, the AER received new information and several submissions after that date.

The AER sets submission deadlines to ensure that there is adequate time to consider the submissions it receives and take them into account in its decision making process. Section 28ZC of the NEL and clause 6.14(a) of the transitional chapter 6 rules expressly provide that the AER may, but need not, consider a submission it receives after the time for making the submission has expired.

The AER has dealt with new information and late submissions on a case-by-case basis in deciding whether or not, or to what extent, it was able to consider the new information or late submission. In deciding whether to consider the new information or late submission, the AER has taken into account the nature of the material, whether it sought to provide new information, and the circumstances surrounding its submission.

Much of the new information and late submissions related to the impacts of the global financial crisis. This crisis has been described by the International Monetary Fund as the deepest shock to the global financial system since the great depression.[1776] Given this extraordinary change in circumstances within the economic environment, the AER has decided where possible, to consider new information and late submissions that related to the impacts of the global financial crisis. Those submissions, or parts thereof, relating to matters other than the global financial crisis have been dealt with on a case-by-case basis.

The AER's consideration of new information and late submissions is detailed in table V.1. Submissions on the supplementary draft decision for public lighting that were received before the closing date for those submissions (27 March 2009) have not been included in the table.

[1776] IMF, *World Economic Outlook*, October 2008, p. xiii.

Table V.1: New information and late submissions received by the AER

Date	Submitted by	Topic	AER consideration
18 February 2009	City of Canterbury	Submission on AER draft decision – public lighting	Fully considered
18 February 2009	Hornsby Shire Council	Submission on AER draft decision – public lighting	Fully considered
20 February 2009	EMRF	Submission on draft decision and revised regulatory proposals	Fully considered
24 February 2009	Origin Energy	Submission on draft decision	Fully considered
10 March 2009	Gosford Shire Council	Submission on AER draft decision – public lighting	Fully considered
6 March 2009	EnergyAustralia	Response to stakeholder submissions	Fully considered
27 March 2009	EnergyAustralia	Risk–free averaging period – letter attaching memorandum from CEG	Fully considered
1 April 2009	Trans Tasman Energy Group	Submission to supplementary draft decision on public lighting	Fully considered
3 April 2009	EnergyAustralia	Submission to supplementary draft decision on public lighting	Fully considered
6 April 2009	EnergyAustralia	CEG memo of evidence – equity raising costs and debt risk premium	Limited consideration, due to limited time available
8 April 2009	SSROC	Supplementary submission to supplementary draft decision on public lighting	Fully considered
9 April 2009	EnergyAustralia	EnergyAustralia's comments on MMA report 'Review of the revised EnergyAustralia forecasts'	Fully considered
15 April 2009	EnergyAustralia	Request that the AER consider expert evidence submitted by TransGrid on 16 February 2009 – risk–free averaging period	Fully considered
16 April 2009	EnergyAustralia	Submission on labour cost escalators, attaching Macromonitor updated forecasts, CEG adjusted forecasts and CEG memo	Limited consideration. Macromonitor report not considered.
17 April 2009	Integral Energy	Request that the AER consider report by Tony Carlton previously submitted by EnergyAustralia – indirect costs of equity and debt raising	Fully considered
22 April 2009	EnergyAustralia	CEG memo on labour cost escalators	Limited consideration, due to limited time available