ETSA Utilities, CitiPower and Powercor Australia

JOINT RESPONSE TO AEMC DIRECTIONS PAPER (ERC0134 / ERC0135)

13 April 2012

Contents

GLOSSARY

Term	Description
2006 TNSP Rule Determination	AEMC, *Rule Determination, National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006 No. 18*, 16 November 2006
2009 SORI	AER, *Electricity Transmission and Distribution Network Service Providers, Statement of the Revised WACC Parameters (Transmission), Statement of Regulatory Intent on the Revised WACC Parameters (Distribution)*, May 2009
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
AER Draft Rules	AER, *Rule Change Proposal, Economic Regulation of Transmission and Distribution Network Service Providers, AER's Proposed Changes to the National Electricity Rules, Part C - Draft Rules*, September 2011
AER Rule Change Proposal	AER, *Rule Change Proposal, Economic Regulation of Transmission and Distribution Network Service Providers, AER's Proposed Changes to the National Electricity Rules*, September 2011
AER's EBSS	AER, *Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008
AER's EBSS Final Decision	AER, *Final Decision, Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008
Aurora	Aurora Energy Pty Ltd
Businesses	ETSA Utilities, CitiPower and Powercor Australia
capex	capital expenditure
capex criteria	the capital expenditure criteria set out in clause 6.5.7(c) of the Rules
capex factors	the capital expenditure factors set out in clause 6.5.7(e) of the Rules
capex objectives	the capital expenditure objectives set out in clause 6.5.7(a) of the Rules
CAPM	capital asset pricing model

CEG	Competition Economists Group
CEG DRP Rule Change Report	CEG, *Critique of AER rule change proposal, A report for ETSA Utilities, CitiPower and Powercor*, December 2011
December Response	ETSA Utilities, CitiPower and Powercor Australia, *Joint response to AER and EURCC Rule Change Proposals,* 8 December 2011
Directions Paper	AEMC, *Directions Paper*, *National Electricity Amendment (Economic Regulation of Network Service Providers) Rule 2012, National Gas Amendment (Price and Revenue Regulation of Gas Services) Rule 2012*, 2 March 2012
DMIS	demand management incentive scheme
DNSP	distribution network service provider
DRP	debt risk premium
EBSS	efficiency benefit sharing scheme
ENA	Energy Networks Association
ENA's Response to MEU Rule Change Proposal	ENA, *Response to Consultation Paper, Proposed Energy Rules Changes: Optimisation of Regulatory Asset Base, Use of Fully Depreciated Assets*, January 2012
ERA	Energy Regulation Authority of Western Australia
ESC	Essential Services Commission of Victoria
ESCOSA	Essential Services Commission of South Australia
EURCC	Energy Users Rule Change Committee of the Energy Users Association of Australia
EURCC Rule Change Proposal	EURCC, *Proposal to change the National Electricity Rules in respect of the calculation of the Return on Debt*, 17 October 2011
EY Report (SA)	Ernst & Young, *South Australia domestic electricity prices 1998-2010: The contribution of network costs, A report for ETSA Utilities*, December 2011
EY Report (Vic)	Ernst & Young, *Victorian domestic electricity prices 1996-2010: The contribution of network costs, A report for the Victorian electricity network businesses*, 9 September 2011
F&A Paper	framework and approach paper
GFC	global financial crisis

IPART	Independent Pricing and Regulatory Tribunal (NSW)
Law	National Electricity Law
MCE	Ministerial Council on Energy
MRP	market risk premium
NEO	national electricity objective set out in section 7 of the Law
NSP	network service provider
opex	operating expenditure
opex criteria	The operating expenditure criteria set out in clause 6.5.6(c) of the Rules
opex factors	The operating expenditure factors set out in clause 6.5.6(e) of the Rules
opex objectives	The operating expenditure objectives set out in clause 6.5.6(a) of the Rules
RAB	regulatory asset base
RPPs	revenue and pricing principles set out in section 7A of the Law
Rules	National Electricity Rules
SCO	Standing Committee of Officials of the MCE
SFG	SFG Consulting
SOCC	statement on the cost of capital
SORI	statement of regulatory intent
STPIS	service target performance incentive scheme
TNSP	transmission network service provider
Tribunal	Australian Competition Tribunal
WACC	weighted average cost of capital

1 INTRODUCTION

The Businesses thank the AEMC for the opportunity to comment on its initial views in respect of the AER and EURCC Rule Change Proposals, as set out in its Directions Paper of 2 March 2012.

As described in detail in their December Response, the Businesses consider that the AER has, in the main, failed to substantiate the need for change to the current Rules.[1] The AER has not presented sufficient evidence to justify a departure from the existing Rules, or demonstrated that its proposed form of the Rules would better achieve the NEO and the RPPs.

The Businesses again observe that there are many reasons why network costs are increasing. Higher reliability standards, ageing networks, continued increases in peak demand with declining sales growth and the increasing cost of funds, as well as mandated government programs (such as to support security of supply in central business districts and, in Victoria, the advanced metering infrastructure rollout and programs giving effect to the recommendations of the 2009 Victorian Bushfires Royal Commission), all contribute to higher prices for network services.

Further, many of the concerns raised by stakeholders are not borne out in either the Victorian or South Australian context. For example, capex overspends have not historically occurred in either State. In addition, the distribution use of system charges in Victoria in fact decreased by 20% in real terms over the period 1996-2010,[2] and decreased by 22% over the period 1998-99 to 2010-11 in South Australia.[3] This demonstrates that capex overspends and rising network charges elsewhere have not solely been the product of the Rules, but rather a product of a range of factors. The AEMC itself highlighted that the price and service outcomes experienced by customers are a function of three drivers: the legal framework; the application of the framework by the regulator and the corporate governance of electricity NSPs.[4] To the extent the price of network services are considered too high it is necessary to understand the degree to which these outcomes are a product of the Rules, as opposed to other drivers.

The Businesses consider that the existing Rule provisions, in most instances, strike the right balance between prescription and discretion and thus no changes to the Rules are necessary. In any event, it is premature to be contemplating significant changes to the regulatory framework. Fundamentally changing the framework for the regulation of NSPs so soon after the Rules came into force will undermine investor certainty, compromising NSPs' ability to make investments in their networks. Significant investment decisions have been made, and will be made, on the basis of the existing regulatory framework and outlook, and as such the Proposals warrant transparent, balanced and careful consideration.

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[1] See, for example, December Response, p12.

[2] EY Report (Vic), p10.

[3] EY Report (SA), p10. Even when the price increase in 2010-11 is reflected in the analysis, there has been little change in real terms in the distribution use of system charges in South Australia since 1998-99: EY Report (SA), p28.

[4] Directions Paper, p21.

That said, the Businesses appreciate that some changes to the Rules, in particular the regulatory determination process and the cost of capital provisions, would better promote the NEO and the RPPs.

This response constitutes the Businesses' joint response to the AEMC's Directions Paper. The Businesses' detailed response to the AER and EURCC Rule Change Proposals and specific drafting suggestions are set out in their December Response. The Businesses continue to rely on their December Response and request that the AEMC take both responses into account in making its draft determination regarding the AER and EURCC Rule Change Proposals.

The remainder of this response deals with the assessment framework proposed by the AEMC and then each of the key issues raised by the AEMC. The response is structured as follows:

- section 2 responds to Chapter 2 and Appendix B of the Directions Paper, 'Assessment Framework' and 'Factors affecting the NGO or NEO';
- section 3 responds to Chapter 5 of the Directions Paper, 'Rate of return frameworks';
- section 4 responds to Chapter 6 of the Directions Paper, 'Cost of debt';
- section 5 responds to Chapter 4 of the Directions Paper, 'Capex incentives (and related issues)';
- section 6 responds to Chapter 3 of the Directions Paper, 'Capex and opex allowances'; and
- section 7 responds to Chapter 7 of the Directions Paper, 'Regulatory determination process'.

The Businesses have provided the AEMC with a copy of or links to each of the additional documents relied on in this response. A list of these documents is included at Appendix B.

2 ASSESSMENT FRAMEWORK

This section sets out the Businesses' response to Chapter 2 and Appendix B of the Directions Paper, 'Assessment Framework' and 'Factors affecting the NGO or NEO'.

AEMC's initial view

In its Directions Paper, the AEMC proposes an assessment framework for considering Rule change requests. The AEMC's initial view is that if met, the following 'conditions' would promote the NEO:[5]

- Demand is met at lowest total system cost.
- Efficient investment in and use of assets takes place where:
    - use of existing assets is optimised (i.e. NSPs make optimum decisions regarding the use of their assets);

[5] Directions Paper, pp8-9, Appendix B.

  - network is managed to meet changing demand; and
  - assets are replaced at the end of their useful life (i.e. the point up to which they can safely continue to be used to deliver the outputs expected of the assets).
- NSPs recover efficient costs.
- Efficiency and innovation is rewarded.

The AEMC also sets out the factors it considers will impact on the achievement of the NEO and identifies which factors are relevant to the assessment in each chapter of the Directions Paper.[6]

Businesses' response

The Businesses' response to the following issue for further comment identified in the Directions Paper is set out below:

Question 1	Is the Commission's assessment approach, as set out in Chapter 2 and Appendix B, appropriate? Are there other factors that should be taken into account in assessing the rule change requests?

The Businesses appreciate the AEMC making its proposed framework for assessing the Rule change requests explicit in the Directions Paper.

While it is acknowledged that the use of an assessment framework will assist the AEMC in its deliberations on the proposed Rule changes, the Businesses are of the strong view that the assessment framework should not be substituted for an assessment of the Rule change requests against the provisions of the Law. In *Telstra Corporation Limited v Australian Competition Tribunal*, the Full Federal Court agreed with Telstra that the Tribunal had fallen into error by devising a set of rules (which it called a 'road map') for the making of its decision in that case, rather than directly applying the statutory test.[7] While a framework may be a useful tool in assessing a Rule change proposal, the ultimate test to be applied (in this instance) before a Rule is made is that set out in sections 88 and 88B of the Law. That is, the AEMC must:

- be satisfied that a given Rule will or is likely to contribute to the achievement of the NEO; and
- where the Rule is with respect to distribution system revenue and pricing and regulatory economic methodologies (as in the present case), take into account the RPPs.

The AEMC's proposed assessment framework identifies the 'conditions' which, if satisfied, the AEMC considers will promote the NEO. As acknowledged by the AEMC[8] and as set out above, however, the AEMC must also take into account the RPPs in making its determination.

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[6] Directions Paper, pp9-11, Appendix B.

[7] *Telstra Corporation Limited v Australian Competition Tribunal* [2009] FCAFC 23; (2009) 175 FCR 201 at [173]-[175].

[8] Directions Paper, p6.

The conditions identified by the AEMC largely appear to reflect the relevant RPPs.[9] To the extent the AEMC's framework is applied, the RPPs from which the framework was developed should be borne in mind. A comparison of the AEMC's conditions and the RPPs is set out in Figure 1 below. Figure 1 also shows the 'factors' that the AEMC considers affect each condition and that the AEMC considers are within the scope of the present review.

[9] Two RPPs not set out are: 1) that regard should be had to the RAB with respect to the distribution or transmission system adopted in any previous determination or in the Rules (section 7A(4) of the Rules); and 2) that the price or charge for the provision of a direct control service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which the price or charge relates (section 7A(5) of the Rules).

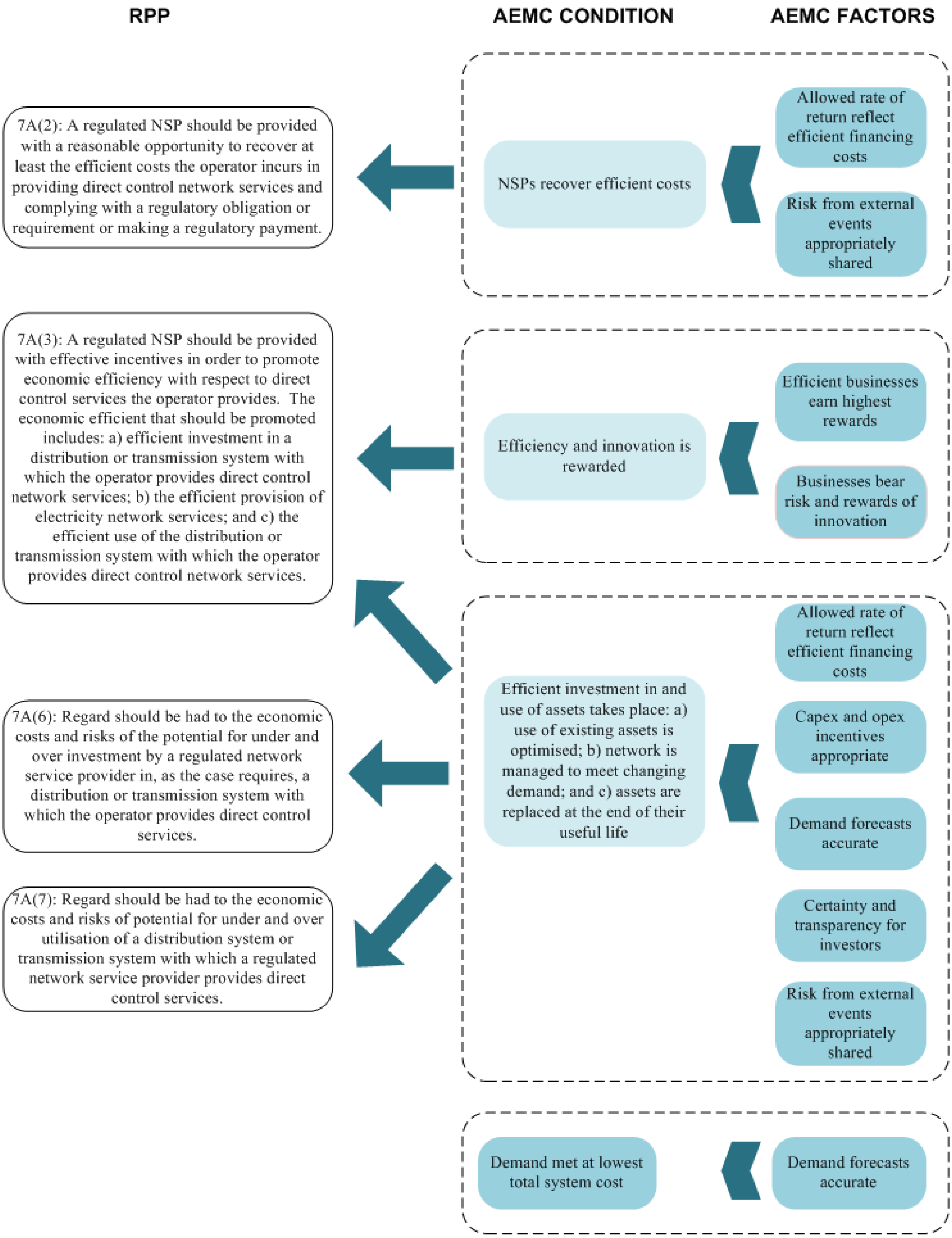

Figure 1: Businesses' analysis of the AEMC's assessment framework against the RPPs

The importance of applying the legislative test directly, rather than looking solely at the 'conditions' and 'factors' in the AEMC's proposed assessment framework can be demonstrated by way of two examples.

First, the AEMC identified the following factors as affecting the NEO in Chapter 3 ('Capex and opex framework'): 'capex and opex incentives appropriate'; 'certainty & transparency for investors'; 'efficient businesses earn highest rewards'; and 'accurate demand forecasts for regulation'. The factors identified by the AEMC do not appear to take into account the key RPP of relevance, which is that a regulated NSP should be provided with a reasonable opportunity to recover at least its efficient costs in providing direct control network services and complying with a regulatory obligation or requirement or making a regulatory payment.

Second, the AEMC identified the following as a 'condition' required to meet the NEO: 'demand is met at lowest total system cost'. The AEMC's discussion of that condition in Appendix B discloses that the condition does not arise from the RPPs, but rather, comes from the NEO directly. It is not clear to the Businesses on what basis the condition is relevant in the current rule change process. Nonetheless, the Businesses wish to observe that if the condition was to properly reflect the NEO, it should be clarified that the cost being considered is the long run total system cost. Without such a clarification, it is not clear the condition would promote the NEO because minimising costs in the short term may not minimise costs over the longer term and thus may not promote the *long term* interests of consumers as required by the NEO.

3 RATE OF RETURN FRAMEWORKS

This section sets out the Businesses' response to Chapter 5 of the Directions Paper, 'Rate of return frameworks'.

AEMC's initial view

The AEMC's initial preference is to accept the AER's proposal for a single WACC framework for electricity and gas.[10] The AEMC rejects the AER's proposal for the single framework to align with the current framework for electricity transmission because the AEMC is of the view that this framework is not satisfactory (in particular, the AEMC considers flexibility is needed to deal with changes over time as evidence and data change).[11] The AEMC is open to considering different frameworks.[12]

The AEMC does not accept the AER's proposal to exclude merits review of rate of return decisions because, as long as a merits review mechanism is available under the Law for regulatory determinations, the most significant decisions that make them up (i.e. those relating to the rate of return) should be subject to merits review.[13]

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[10] Directions Paper, p93.

[11] Directions Paper, pp80, 92.

[12] Directions Paper, p93.

[13] Directions Paper, p93.

The AEMC does not accept that the frequency of appeals necessarily supports the AER's contention that DNSPs 'cherry-pick' WACC parameters they consider are unfavourable to them.[14] Rather, the AEMC considers the appeals appear to result from the DNSPs being unable to appeal the WACC review.

The AEMC considers that the WACC framework should continue to be based on estimating the WACC for a benchmark efficient firm.[15] The AEMC's preliminary view is that the rate of return framework should provide guiding principles (and not prescribe the methodology or value for parameters) and that the Rules should require the regulator to consider linkages between different WACC parameters.[16]

Businesses' response

The Businesses agree in principle with the establishment of a single, common WACC review framework across electricity and gas distribution and transmission and, for the reasons outlined in their December Response,[17] strongly support the AEMC's rejection of Chapter 6A of the Rules as a basis for that framework.

The Businesses observe, however, that the AEMC's initial views on the appropriate rate of return framework fail to reflect one significant factor contributing to the NEO and the RPPs: regulatory certainty.

As noted in the AEMC's 2006 TNSP Rule Determination, certainty and predictability are critical to fostering efficient network investment.[18] The AEMC recognises this in its proposed framework for assessing the Rule change proposals where it identifies certainty for investors as a key factor influencing the NEO in respect of the rate of return.[19] As discussed below, however, the AEMC appears to have failed to take certainty into account in its discussion of the rate of return framework in Chapter 5 of the Directions Paper.

For the reasons outlined in their December Response,[20] the Businesses consider that a framework based on Chapter 6 of the Rules would best promote the NEO and the RPPs, as well as satisfy the key attributes identified by the AEMC and the Businesses as attributes of a rate of return framework that can produce rates of return that reflect efficient financing costs. The Businesses consider, however, that the existing provisions of Chapter 6 should be amended so that:

- the persuasive evidence requirement in the Rules becomes a 'test' or 'threshold' (rather than a mandatory consideration);

[14] Directions Paper, pp84-85, 92-93.

[15] Directions Paper, p93.

[16] Directions Paper, p93.

[17] December Response, pp104-122.

[18] 2006 TNSP Rule Determination, p31 (Attachment 2 to the December Response).

[19] Directions Paper, p11.

[20] December Response, pp104-122.

- the AER is required to have regard to the inter-relationships between parameters; and
- overall checks on the return on debt and equity can be considered in determining whether there is persuasive evidence justifying a departure from the relevant value, method or credit rating.

Further amendments to the provisions relating to the DRP are described in section 4.

The Businesses' response to the issues for further comment identified in the Directions Paper is set out below.

Question 20	Are some WACC parameter values more stable than others, and sufficiently stable to be fixed with a high degree of confidence for a number of years into the future? Would it be practical for periodic WACC reviews to cover only some parameters that are considered relatively stable in value, and require others to be determined at the time of each regulatory determination?
Question 21	Would it be useful if the AER periodically published guidelines on it proposed methodologies on certain WACC parameters as opposed [to] undertaking periodic WACC reviews that locks in parameter values for future revenue/pricing determinations?

The Businesses consider that the values of at least some WACC parameters (e.g. credit rating, term to maturity of the risk free rate, term to maturity of the DRP, gamma, equity beta and the debt to equity ratio) are relatively stable and slow to change, or are not readily observable and should therefore exhibit some level of regulatory stability, and thus the AER should continue to set these in the SORI or (proposed) SOCC. Other WACC parameters (e.g. risk free rate, DRP and MRP) may be less stable and it would therefore be useful for the SORI/SOCC and/or guidelines to provide guidance on the methodology that is intended to be used to quantify these parameters at the time of a regulatory determination.

While the Businesses support the concept of a SORI/SOCC because such a process can promote regulatory certainty, the Businesses consider that the current framework is flawed in that the SORI is not subject to merits review. If the SORI/SOCC could be appealed, investors and customers would be provided with greater certainty as to the WACC and multiple appeals subsequent to AER determinations could be avoided. As noted by the AEMC, given the rate of return contributes to a significant portion of NSPs' revenues, it is appropriate that there is sufficient regulatory accountability to ensure that any errors potentially made by the regulator are corrected.[21]

The Businesses consider that if non-binding guidelines were introduced in place of a SORI or SOCC, regulatory certainty would be compromised. To address this issue, if the AEMC is minded to introduce non-binding WACC guidelines, the AER should be required (in its regulatory determination) to adopt a value or method or credit rating that differs from the value or method or credit rating that was previously adopted for that particular business only if there is persuasive evidence justifying the departure (discussed further below).

[21] Directions Paper, p93.

Question 22	Given the uncertainty in estimating certain parameters, should the AER be required to produce the best possible values for all parameters or adopt a range from which it can choose a preferred estimate? Which WACC parameters are inter-related and should the rules recognise the inter-relationships of these WACC parameters?

A range would not promote the NEO or the RPPs

The Businesses strongly reject the notion that requiring the AER to determine a range from which it can choose an estimate would promote the NEO and the RPPs.

First, the Rules already provide a mechanism for dealing with uncertainty. Clause 6.5.4(e)(4) of the Rules states that where a credit rating level, value or method cannot be determined with certainty, the AER must have regard to the need to achieve an outcome that is consistent with the NEO and the need for persuasive evidence before adopting a different value or method or credit rating that has previously been adopted for it. Under the Businesses' proposal, the NEO would govern the AER's decision (as it does all of the AER's decisions) and a persuasive evidence test would be applied.

Second, the adoption of ranges of values would only tend to increase (rather than decrease) uncertainty in the determination of the WACC. This is because, in order to fully account for future market developments, the range identified by the AER for some parameters would need to be quite wide. In the absence of requirements governing the decision to select a precise parameter at the determination stage, this gives rise to the potential for arbitrary selection of the AER's 'preferred' estimate within the relevant range, which would offer little certainty and predictability, thus deterring investment, contrary to the NEO and the RPPs.

AER should be required to have regard to inter-relationships between parameters

The Businesses consider that the Rules should explicitly require the consideration of inter-relationships between WACC parameters. The inter-relationships between WACC parameters include:

- MRP and gamma;
- MRP and the risk-free rate;
- MRP and the equity beta;
- equity beta and gearing;
- gearing and credit rating; and
- the overall cost of equity and the cost of debt.

Having regard to inter-relationships between WACC parameters ensures that the overall rate of return gives NSPs the opportunity to recover efficient costs. The significance of the overall rate of return to this RPP has been confirmed as follows:[22]

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[22] *Application by EnergyAustralia and Others* [2009] ACompT 8 at [18] (Attachment 15 to the December Response).

> The national electricity objective provides the overarching objective for regulation under the NEL: the promotion of efficient investment and efficient operation and use of, electricity services for the long term interests of consumers. Consumers will benefit in the long run if resources are used efficiently, that is if resources are allocated to the delivery of goods and services in accordance with consumer preferences at least cost. **As reflected in the revenue and pricing principles, this in turn requires prices to reflect the long run cost of supply and to support efficient investment, providing investors with a return which covers the opportunity cost of capital required to deliver services.**
>
> [Emphasis added in bold.]

The Businesses observe that it is open to the AER under Chapter 6 of the Rules to take into account inter-relationships between parameter values. Any persuasive evidence justifying a departure from a SORI value could be expected to provide persuasive evidence justifying a change in another inter-related value. It is also open to the AER, in any Tribunal review of a WACC decision, to raise any consequential effect of a DNSP's review ground relating to a parameter value on another parameter value and for the Tribunal to address that effect in making its determinations.[23]

The AER appears, however, to have failed to take these inter-relationships into account. For example, in its recent draft decision in respect of the Tasmanian DNSP (Aurora), while contending that it did consider the interaction between individual parameters,[24] the AER considered the MRP in isolation from other components of the cost of equity, in particular, the risk-free rate.[25] In particular, the AER combined a long term historical average MRP with a forward-looking risk free rate. The current risk free rate is low because there has been a flight from risk assets (equity) to less risky assets (government bonds). Therefore, the return on equity in the draft decision is below the long-term average at a time when it is likely to be equal to or more than the historical average (when adjusted for inflation).

The Rules should therefore explicitly require the AER to have regard to the inter-relationships in its preparing its SORI/SOCC and/or guidelines and in making its regulatory determinations.

The Businesses also observe that de-coupling the maturity period for the risk-free rate and the cost of debt (as proposed by the Businesses) will enable consistency between the setting of the MRP and the risk-free rate (and thus allow the AER to take into account the inter-relationship between those parameters) and also provide greater flexibility in estimating the return on debt.

Question 23	How do the outcomes of the persuasive evidence test applying at the time of the regulatory determinations in Chapter 6 of the NER differ from the NGR rate of return framework? Does the persuasive evidence test make it less likely that values of WACC parameters will be updated as quickly as under the NGR framework, or vice versa?

The requirement for 'persuasive evidence' before adopting in the SORI a value, method or credit rating level that differs from value, method or credit rating level previously adopted has offered the

[23] December Response, p121.

[24] AER, *Draft Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17*, November 2011, p254 (Attachment 72 to the December Response).

[25] AER, *Draft Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17*, November 2011, pp221-237 (Attachment 72 to the December Response).

AER adequate flexibility to depart from historical values. As shown in the December Response,[26] in the 2009 SORI, the AER concluded there was persuasive evidence to depart from the historical values in respect of three of the five parameters.

Further, in applying the persuasive evidence requirement in the context of departing from the SORI at the distribution determination stage, the AER has:

- in the Victorian distribution determinations, concluded there was persuasive evidence justifying a departure from the value of gamma set out in the 2009 SORI;[27] and
- in the Tasmanian draft distribution determination, concluded that there was persuasive evidence to justify a departure from the MRP and gamma values set out in the 2009 SORI.[28]

The Businesses therefore submit that a requirement for 'persuasive evidence' does not impede the necessary flexibility to update parameters over time.

For the reasons outlined in the Businesses' December Response, given the importance of a robust evidentiary basis before a previously adopted value or method, or credit level rating, can be departed from, the Businesses consider that the persuasive evidence requirement at the SORI/SOCC stage should be in the nature of a 'test' or 'threshold' (i.e. rather than a mandatory consideration).[29] Such a requirement would ensure that the AER has a robust evidentiary basis before departing from a previously adopted value or method or credit rating, which would contribute to the certainty and predictability of the return on network investment. This is in turn important for the creation of incentives for, and the promotion of, efficient investment and thus the achievement of the NEO and the RPPs.

Question 24	How has the rate of return framework under the NGR worked alongside the NER frameworks?
Question 25	Are there any concerns about lack of guidance in the NGR on how the AER and ERA will approach the rate of return decision? To what extent is the rate of return framework under the NGR influenced by the WACC approach adopted for the electricity sector by these regulators?

The Businesses agree it is difficult to evaluate the outcomes of the gas framework because the AER's approach is significantly influenced by the approach adopted for the electricity sector. A

[26] December Response, pp119-120.

[27] December Response, p119.

[28] AER, *Draft Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17*, November 2011, pp221-238 (Attachment 72 to the December Response).

[29] December Response, pp124-132. While the submissions were made in the December Response in respect of the application of the persuasive evidence requirement at the SORI stage, they are equally applicable under any proposed application of the threshold at the regulatory determinations stage.

comparison of the AER's decisions where the SORI was applicable in the electricity distribution context and its decisions to date regarding regulated gas businesses is set out in Table 1 below.[30]

WACC parameter	2010			2011			
	Electricity DNSPs[31]	NSW gas distribution businesses[32]	ACT gas transmission business[33]	QLD gas transmission businesses[34]	SA gas transmission business[35]	NT gas transmission business[36]	*Tasmanian electricity DNSP (draft)[37]*
Equity beta	0.8	0.8	0.8	0.8	0.8	0.8	*0.80*
Market risk premium	6.5%	6.5%	6.5%	6.0%	6.0%	6.0%	*6.0%*
Debt to equity ratio	0.6	0.6	0.6	0.6	0.6	0.6	*0.6*
Credit rating level	BBB+	BBB+	BBB+	BBB+	BBB+	BBB+	*BBB+*
Assumed utilisation of imputation credits (gamma)	0.65	0.65	0.65	0.25	0.25	0.25	*0.25*

Table 1: Comparison of AER WACC decisions for electricity DNSPs and gas businesses

[30] The 2009 SORI did not apply to the AER's New South Wales and ACT distribution determinations because the Transitional Chapter 6 set out in Appendix 1 to the Rules and applicable to those Determinations under clause 11.15.2 of the Rules does not provide for this.

[31] References are provided in the December Response at page 120 (Table 4).

[32] AER, *Final Decision-Public, Wagga Wagga Gas Distribution Network*, March 2010, pp6, 34, 46, 50; AER *Final Decision-Public, Jemena Gas Networks, Access arrangement proposal for the NSW Gas Networks*, 11 June 2010, pp 13-14, 184, 200.

[33] AER, *Final Decision-Public, ACT, Queanbeyan and Palerang gas distribution network*, 26 March 2010, pp6, 47, 70, 73.

[34] AER, *Final Decision, APT Allgas, Access arrangement proposal for the QLD gas network*, June 2011, ppxiii, 41, 139: AER, *Final Decision, Envestra Ltd Access arrangement proposal for the QLD gas network*, June 2011, pp54, 57, 190.

[35] AER, *Final Decision, Envestra Ltd Access arrangement proposal for the SA gas network*, June 2011, ppx, xiv, 59, 202.

[36] AER, *Final Decision-Public, N.T Gas, Access Arrangement for the Amadeus Gas Pipeline*, July 2011, pp80, 85-86, 164.

[37] AER, *Draft Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17*, November 2011, pp211, 220, 238.

Table 1 shows that the equity beta, debt to equity ratio and credit level rating have been consistently applied across the electricity distribution and gas businesses. An MRP of 6.5% was uniformly applied until mid 2011, at which time the AER commenced applying an MRP of 6%. This is consistent with the AER's proposed approach in respect of the only electricity DNSP in respect of which there has been a determination since that time (namely, Aurora).[38]

Similarly, whereas prior to the Tribunal's decision on gamma in Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 in May 2011 the AER consistently adopted a value for gamma of 0.65, after that decision, the AER has consistently adopted a gamma value of 0.25 across gas businesses and electricity DNSPs.

While it is difficult to evaluate the outcomes of the gas regime in circumstances where it is influenced by the electricity regime, the Businesses do not consider that the gas WACC framework best promotes the NEO and the RPPs. This is because it lacks guidance for the regulator and would result in greater uncertainty for investor and consumers. By contrast, Chapter 6, with the amendments suggested by the Businesses, strikes the right balance between flexibility and certainty, two attributes the Businesses submit are key to ensuring the WACC framework promotes the NEO and the RPPs.

Question 26	Are there reasons to adopt a WACC definition other than the vanilla post-tax nominal definition that is used under the NER? Alternative proposals should explain why that alternative is likely to result in a better WACC estimate.
Question 27	Should the AER/ERA be given discretion to consider models other than CAPM when estimating the required return on equity under the NGR? What prescription or principles could the rules contain to guide the way in which information from other models might be used to produce a better WACC estimate?

The Businesses are of the view that there is no reason to change the current definition of the rate of return as a vanilla post-tax nominal WACC.

Whereas under the National Gas Rules, the AER is able to use models other than the CAPM as its primary model in determining a rate of return on capital (the only requirement is that the model used be 'a well accepted financial model'[39]), the Businesses consider that the CAPM should continue to be the primary model used in determining a rate of return on capital. The AER should have discretion to use models and approaches other than the CAPM in cross-checking the return on debt and equity in determining whether there is 'persuasive evidence' justifying the departure from the SORI/SOCC (or previously adopted) values, methods or credit ratings.

[38] AER, *Draft Distribution Determination, Aurora Energy Pty Ltd, 2012-13 to 2016-17*, November 2011, p211 (Attachment 72 to the December Response).

[39] Clause 87(2)(b) of the National Gas Rules.

Question 28	Are there any reasons why an appropriate WACC estimate cannot be provided to NSPs and gas service providers from a common WACC framework, without necessarily requiring the same parameter values to be adopted across the electricity transmission, electricity distribution and gas sectors?
Question 29	Which rate of return framework would best meet the key attributes identified? Are there any other attributes that should be considered?

There is no reason why the same parameter values need to be applied across electricity and gas businesses and any framework should offer the AER flexibility to apply different WACC parameter values to each. The Chapter 6 framework, as varied in accordance with the Businesses' proposal, applied across all businesses would allow for this as the parameters could vary where the relevant benchmark characteristics of the different businesses vary.

The Businesses submit that the Chapter 6 framework, with the adjustments described above, best meets the key attributes identified by the AEMC as attributes that can produce rates of return that reflect efficient financing costs[40] as follows:

Attribute identified by the AEMC	Reasons why the Businesses' proposed framework exhibits the attribute
Is based around estimating a rate of return for benchmark efficient firms	The notion of a benchmark for an efficient firm is (and should remain) built into the Rules (clauses 6.5.2(b) and 6.5.4(e)(3)).
Allows methodologies for parameters to be driven by principles and reflect current best practice	There is scope under the Rules to develop approaches and methodologies in line with best regulatory practice. The Businesses note, however, that this attribute should be balanced with the need for certainty and predictability (discussed below).
Allows flexibility to deal with changing market conditions	The Chapter 6 framework allows values, methods and credit ratings to change where there is 'persuasive evidence' justifying the change. The Businesses note that a desire for flexibility must be balanced with the need for certainty and predictability (discussed below). The persuasive evidence test strikes the right balance between flexibility and certainty.
Recognises inter-relationships between some parameter values	Any persuasive evidence justifying a departure from a SORI/SOCC or previously adopted value, method or credit rating may provide persuasive evidence justifying a change in another inter-related value. Further, under the Businesses' proposal, the Rules would require the AER to have regard to the inter-relationships between parameters and an overall check could be conducted on the return on debt and equity in determining whether there is persuasive evidence justifying the departure from a SORI/SOCC or previously adopted value, method or credit rating.
Creates a framework of accountability for both the regulator and the NSP in determining an appropriate rate of return	This is achieved by an appropriate level of prescription and the availability of merits review.

The Businesses observe that the AEMC has not recognised key attributes of a rate of return framework identified by the Businesses in their December Response as necessary to ensure the

[40] Directions Paper, pp91-92.

promotion of the NEO and consistency with the RPPs.[41] The Businesses observe these attributes are promoted by their proposed WACC framework as follows:

Attribute identified by the Businesses	Reasons why attribute is necessary to promote NEO and RPPs	Reasons why the Businesses' proposed framework exhibits the attribute
The need to ensure incentives for efficient investment and the reasonable opportunity to recover at least efficient costs (NEO and RPPs)	If a rate of return is not adequate, an NSP will not be provided with a reasonable opportunity to recover at least its efficient costs and thus will not have incentive to achieve the efficiency objectives of the NEO and the RPPs.[42]	The Businesses' proposed WACC framework provides an appropriate rate of return to be established in regulatory determinations, which ensures efficient investment is undertaken and provides for the recovery of efficient costs.
Certainty and predictability	Certainty and predictability are critical to fostering efficient network investment.[43] The AEMC recognises this in its proposed framework for assessing the Rule change proposals, where it identifies certainty for investors as a key factor influencing the NEO in respect of the rate of return.[44]	The application of a persuasive evidence test provides an appropriate level of certainty and predictability.

For the reasons outlined, the Businesses consider that their proposed framework (i.e. the process in Chapter 6 with the amendments described above) best promotes the NEO and the RPPs.

4 COST OF DEBT

This section sets out the Businesses' response to Chapter 6 of the Directions Paper, 'Cost of debt'.

AEMC's initial view

The AER proposed that the cost of debt methodology should be left to its discretion in the periodic WACC review. The EURCC proposed that the Rules be amended to specify that the return on debt be estimated using:

- a 5 year rather than a 10 year maturity debt so as to reflect current NSP practice;
- all broad BBB and A rated corporate debt issued in Australia, so as to ensure a more liquid market of bonds to establish the benchmark; and
- a five year trailing average return on debt.

[41] December Response, pp146-147.

[42] See the discussion of the Tribunal's findings in this regard in the December Response, pp140-141.

[43] 2006 TNSP Rule Determination, p31 (Attachment 2 to the December Response).

[44] Directions Paper, p11.

The AEMC agrees that the current approach to the cost of debt in the Rules is problematic and there is evidence indicating that the DRP allowances appear to exceed the interest rate on debt at which NSPs have historically borrowed.45 However, the AEMC has concerns with AER's proposal. The AEMC's initial view is that the cost of debt methodology should be determined by the regulator (and not detailed in the Rules) so the regulator has the flexibility to re-specify the benchmark when necessary.[46]

The AEMC believes that the EURCC's proposal to use the trailing average approach to estimate the cost of debt has some merit but is concerned it may not provide the level of flexibility that is desirable in a rate of return framework.[47]

The AEMC considers that the Rules should not limit the range of evidence that can be considered and that this should be for the regulator to decide.[48]

Businesses' response

The Businesses urge the AEMC to review their December Response, in which they set out in detail: the Businesses' current actual debt financing practices; the implications of the NEO and the RPPs for the estimation of the cost of debt having regard to these practices; the criteria that should be adopted by the AEMC for the purposes of assessing any Rule change in relation to the cost of debt; the Businesses' views regarding 'the problems' with the current Rule provisions; the Businesses' assessment of the AER and EURCC Rule Change Proposals; and an alternative Rule change that the Businesses submit addresses 'the problems' identified and is consistent with the assessment criteria outlined and thus promotes the NEO and the RPPs.[49]

The Businesses submit their alternative proposed Rule change for the cost of debt set out in the December Response, which provides for the cost of debt to better reflect actual efficient financing practices, is consistent with the criteria they have developed for the assessment of cost of debt Rule changes and thus would better promote the NEO and the RPPs.[50]

Importantly, the Businesses' alternative Rule change for the cost of debt differs from the Rule change set out in the EURCC Rule Change Proposal in that it:

- only prescribes a trailing average in respect of the debt margin, not the total cost of debt;
- does not prescribe the term of the debt margin in the Rules (the Businesses' December Response emphatically demonstrates that the EURCC's proposal for a five year term is flawed and would significantly under-compensate NSPs); and

[45] Directions Paper, pp118-119.

[46] Directions Paper, p119.

[47] Directions Paper, p119.

[48] Directions Paper, p112.

[49] December Response, pp137-155.

[50] December Response, pp152-155.

- explicitly recognises other efficient debt costs such as early refinancing, hedging and debt raising costs which can be a material cost.

Regarding the issues of data availability, the Businesses support the AEMC's initial view that the AER should not be constrained, but rather should have regard to a wide range of data in estimating the DRP. As noted in the December Response,[51] the Victorian DNSPs submitted to the AER in their recent regulatory review process that, in estimating the DRP, the AER should have regard to a wide range of data (including BBB+ bonds with maturities of less than 10 years, floating rate bonds and bonds with ratings other than BBB+ with maturities close to 10 years). Further, the AER's ability to do so has been confirmed by the Tribunal.[52]

For the reasons outlined above, the Businesses observe at the outset that any changes to the return on debt provisions in the Rules should not diminish existing merits review appeal rights in respect of return on debt. The Businesses would not support changes to the Rules to provide for a trailing average approach if those changes diminished existing merits review rights in respect of the return on debt.

The Businesses make a further preliminary comment that the design of any Rule change in relation to a trailing average approach has potential implications for the debt risk position of network companies and for merits review rights, and thus will require significant consultation before it can be successfully implemented.

The Businesses' responses to the issues for further comment identified in the Directions Paper are set out below.

Question 30	Is the benchmark DRP likely to overstate the prevailing cost of debt, having regard to the suggestion that the overstatement may be a reflection of shorter maturity debt leading to a higher refinancing risk for NSPs? What weight should be placed on the views of market analysts on the ability of stock market listed NSPs to out-perform their cost of debt allowances?

As discussed in the December Response, the Businesses accept that there may be a divergence between benchmark DRP and the prevailing actual DRP. [53] This has been the case recently, as there has been a strong investor preference for shorter term debt (driven primarily by the lack and cost of longer term debt in the wake of the GFC).

However, in these circumstances, lower actual cost of debt (relative to the benchmark) will be offset by higher cost of equity as there is a shifting of risk. In short, there is scope for NSPs to outperform the benchmark, but this implies taking on higher refinancing risks. As noted in the December Response,[54] in the CEG DRP Rule Change Report, CEG concludes that there is no evidence of a 'gap' between actual and benchmark WACC arising from the DRP. While there is a

[51] December Response, p145.

[52] December Response, p146. Subsequent to the December Response, the Tribunal further confirmed the position in *Application by United Energy Distribution Pty Limited* [2012] ACompT 1 at [403]-[407].

[53] December Response, pp137-146.

[54] December Response, pp143-144.

DRP 'gap', it is primarily a function of differences in the maturity periods. The DRP 'gap' is expected to be more than offset by the return on equity 'gap' and thus recent benchmark WACC determinations have not been compromised by the apparent DRP 'gap'.

Nonetheless, the Businesses consider that the benchmark DRP (as defined in the Rules) does not reflect efficient financing practices engaged in by NSPs and may either over-state or understate the actual cost of debt. As discussed in the December Response,[55] it is not prudent, or even possible, for the Businesses to refinance their entire debt portfolio and/or to fund new capex requirements during the averaging period used to estimate the risk free rate for the AER's determinations. While the Businesses seek to hedge the interest rate risk that arises under the regulated cost of debt in the WACC, the Businesses cannot hedge the fixed credit margin over variable interest rate (the 'debt margin').[56] The underlying debt margin is embedded at the time debt is financed or refinanced. If the allowed debt margin is materially in excess of the underlying debt margin then the NSPs will be over-compensated. If the allowed margin is materially lower then the NSPs will be under-compensated. The current Rules promote these windfall gain/loss outcomes by not recognising that the debt margin is locked in at the time of financing or refinancing.

Question 31	What are the pros and cons of the recent approaches taken by the IPART and the ERA in estimating the DRP?
Question 32	What evidence is there that the DRP benchmark in the NER may have changed? Would it be appropriate for the regulator to specify the DRP benchmark in any periodic reviews or would it be more appropriate to specify it at the time of the determinations?

The Businesses consider that there are significant deficiencies in the approaches recently adopted by IPART and the ERA in estimating the DRP.

Whereas IPART and the ERA have adopted shorter term benchmarks,[57] the Businesses consider that 10 years continues to be an appropriate benchmark for estimating the debt margin. The use of shorter maturity instruments by IPART and the ERA does not take into account the increased refinancing risk associated with shorter maturity debt and the implications of this for the cost of equity.[58] The temporary change in financing practices in response to the GFC has not only impacted on debt costs, but refinancing risk has lead to a higher cost of equity. The approach also does not reflect businesses' actual financing practices. While interest rate hedging is closely linked to the length of the regulatory period (five years), in normal market conditions, debt is issued with an average tenure of at least 10 years. The Businesses observe in this regard that the weighted average term to maturity of the total outstanding debt of the Businesses as at November 2011 was 9.3 years (this being after some long-dated debt was refinanced to debt with a shorter term to maturity).[59]

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[55] December Response, p138.

[56] December Response, p138.

[57] Directions Paper, p109.

[58] Refinancing risk is discussed in the December Response, p140; the effect of shorter term debt on the cost of equity is discussed at p143.

[59] December Response, p138.

While the GFC has resulted in the Businesses raising debt with a shorter term to maturity, in normal market conditions, the Businesses would expect, indeed prefer, to issue longer tenure debt (i.e. 10 plus years).

Neither the AER nor the EURCC has provided any evidence of a structural break in the way in which businesses finance.

Further, as noted by SFG,[60] no evidence has been provided to suggest that the yield on bonds of a given credit rating in general are higher than the yields on bonds for regulated utilities with the same credit rating.

The Businesses submit that BBB+ continues to be an appropriate credit rating benchmark. There is no evidence to suggest that the credit rating for a benchmark efficient NSP has changed.

As noted above, adopting a BBB+ credit rating and 10 year term to maturity benchmark does not preclude the use of bonds other than bonds exhibiting those characteristics for the purposes of estimating the DRP.

Question 33	Is the EURCC's proposal of establishing the cost of debt using historical trailing average compatible with the overall framework for estimating a forward-looking rate of return? What are the potential benefits costs if the estimate is less reflective of the prevailing cost of debt for NSPs?
Question 34	What possible changes would be required in the NER to implement the EURCC's trailing average approach?

The Businesses' December Response[61] explained why a trailing average return on debt margin is more consistent with the NEO and the RPPs compared to the EURCC's proposed trailing average return on debt and compared to the existing Rule provisions. In summary, the Tribunal has concluded that, if an NSP is not provided with a reasonable opportunity to recover at least its efficient costs, it will not have incentives to achieve the efficiency objectives of the NEO and the relevant RPPs. A benchmark trailing average return on debt margin will better estimate the total efficient costs of NSP debt compared to the current approach to estimate the incremental return on debt. Therefore a benchmark trailing average return on debt margin is more consistent with the NEO and the RPPs.

While this is the case, the Businesses:

- do not consider a trailing average could be incorporated as an option for determining the DRP (i.e. in addition to provisions providing for an approach consistent with the existing provisions); and
- note that the implications for merits review of cost of capital decisions should be carefully examined before any Rule changes are made.

[60] SFG, *Preliminary analysis of rule change proposals*, *Report for AEMC*, 27 February 2012 at [26].

[61] December Response, pp140-142.

The Businesses do not consider that a trailing average could be incorporated as an option for NSPs and the AER in the Rules. There is a fundamental difference in the principle underpinning the current approach and a trailing average approach: the current approach estimates the incremental cost of debt and the trailing average approach estimates the average cost of debt. Having the option in the Rules to select either could result in opportunism, with parties advocating the approach more favourable to them (in light of historic and expected market conditions) at the time.

A trailing average debt margin might be implemented via an annual price adjustment mechanism to adjust prices each year for the difference between the forecast trailing average debt margin and an AER determined trailing average. Such an approach would remove the right of the Businesses to merits review of an AER decision on the debt margin. This outcome would not achieve a key attribute of a rate of return framework as proposed by the AEMC and endorsed by the Businesses, namely, that the framework creates a framework of accountability. A compromise might be for each distribution determination to adopt a debt margin which is a combination of a backward looking average debt margin benchmark and a forward looking debt margin benchmark, with no annual price adjustments for debt margin during the regulatory period. The determination of the composite debt margin would be merits appealable because it would be part of the distribution determination.

To support a trailing average approach, changes to the Rules would be required (at a minimum) to:

- Amend the return on debt definition, and in so doing de-couple it from the nominal risk free rate.
- Remove the requirement for return on debt to be forward-looking.

However, the actual design of a trailing average approach would require careful consideration and significant further consultation to ensure that all issues associated with its implementation are properly addressed.

5 CAPEX INCENTIVES (AND RELATED ISSUES)

This section sets out the Businesses' response to Chapter 4 of the Directions Paper, 'Capex incentives (and related issues)'.

5.1 CAPEX INCENTIVES

AEMC's initial view

The AEMC's initial view is that there are two key issues with the current capex framework:

- the power of incentives to decrease capex declines during the regulatory control period and there may be incentives to defer capex in an inefficient way;[62] and
- the framework does not provide sufficient regulatory scrutiny (ex ante or ex post) of capex in excess of the capex allowance, creating a risk it may be inefficient.[63]

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[62] Directions Paper, pp41-43.

[63] Directions Paper, pp43, 45.

However, the AEMC has concerns with the AER's proposal that only 60% of any capex overspend be included in the RAB and is minded to explore other options for dealing with the problems raised.[64]

Businesses' response

As noted in their December Response,[65] the Businesses share the AEMC's concerns that the AER's proposed 60/40 sharing mechanism for any capex above the capex allowance is contrary to the NEO and the RPPs. The AER's proposal has the potential to deter efficient investment in the network and fails to provide DNSPs with a reasonable opportunity to recover their efficient costs.

The Businesses observe that it is premature to form a concluded view as to the impact of the existing regulatory regime on actual capex incurred. The New South Wales and Queensland capex data referred to by the AER in its Rule Change Proposal is irrelevant in the context of an assessment of the incentives under the Rules because the determinations referred to were made before the AER assumed responsibility for the regulation of the relevant DNSPs and before the Rules applied.[66] In any event, the experience in New South Wales and Queensland can be contrasted with the experience in other states, including Victoria and South Australia, where actual capex was about the same or less than the regulatory benchmark.[67]

The Businesses therefore agree with the AEMC that the AER has not established that the Rules provide NSPs with an incentive to spend more than the capex allowance.

The Businesses' responses to the following issue for further comment identified in the Directions Paper are set out below:

Question 8	What is the best option for dealing with the capex incentive issues identified in the Directions Paper?

The Businesses agree there is scope to further enhance the capex incentives under the regulatory framework. However, providing for optimisation of the RAB or an ex post review of capex would not promote the NEO or the RPPs. The Businesses instead support the development of an EBSS for capex to address the issues with the existing capex regime raised by the AEMC.

Optimisation of the RAB would not promote the NEO and the RPPs

The Businesses are strongly opposed to the optimisation of the RAB at regulatory resets. The Businesses support the ENA's Response to the MEU Rule Change Proposal (regarding optimisation of RAB and use of fully depreciated assets) in which the ENA observed that optimisation of the RAB is a disproportionate and unworkable solution to any finding that capital efficiency incentives need to be strengthened,[68] which would create new disincentives to investment and additional

[64] Directions Paper, p43.

[65] December Response, pp70-76.

[66] See the discussion in the December Response, p71.

[67] December Response, pp70-71.

[68] ENA's Response to the MEU Rule Change Proposal, p10.

regulatory risks requiring offsetting compensation for the risk that past investments will be stranded.[69] For the reasons described in detail in the ENA's Response to the MEU Rule Change Proposal, optimisation of the RAB would not result in the achievement of the NEO or be consistent with the RPPs.

An ex post review of capex would not promote the NEO and the RPPs

As the AEMC is aware, the AEMC's decision to allow NSPs to roll all actual capex into the RAB (i.e. and not to conduct an ex post review of capex) was a deliberate policy decision, designed to ensure NSPs had appropriate incentives to invest in sufficient capacity to maintain service levels amid dynamic demand conditions.[70] Rolling actual capex into the RAB removes the uncertainty that would otherwise face NSPs if an ex post review of the capex was undertaken. Uncertainty has the potential to deter NSPs from incurring efficient capex. For these reasons, the Businesses maintain that an ex post review of the prudency and efficiency of capex would not promote the NEO and would be contrary to the RPPs.

While the AEMC observes that an ex post review of capex would address the 'supervision gap', an appropriately designed EBSS applied to capex would address the same issue without giving rise to the potential risks of underinvestment associated with an ex post review of capex. As noted by the AER in its EBSS Final Decision:[71]

> It is generally accepted that firms are better placed than a regulator to effectively judge whether a particular project or organisational structure reflects efficient production. In the presence of this information asymmetry, the AER considers it is preferable to apply a light-handed approach to regulation, while providing a system of broad financial incentives to induce the firm to operate efficiently.

The AER's EBSS in respect of opex is designed to provide DNSPs with 'a continuous incentive to improve the efficiency of its operating expenditure (opex) and in doing so to reveal its efficient level of opex'.[72] An appropriately designed EBSS in respect of capex would similarly encourage NSPs to reveal their efficient level of capex, and thus avoid the need for direct regulatory scrutiny and the associated risk of regulatory error and disincentive to incur efficient capex.

In the event the AEMC proposes to provide for an ex post review of capex in the Rules, clearly specifying the circumstances in which an ex post review will be conducted is essential to mitigating the risk of efficient investment being deferred. The Businesses consider that the Rules should provide that an ex post review of capex can only be conducted where:

- an NSP has incurred capex above a certain level identified in the Rules (which should be a level in excess of the capex allowance in the relevant distribution determination, e.g. a certain percentage above the capex allowance); and
- the overspend should be calculated by reference to capex allowance over the entire regulatory control period (i.e. rather than capex allowance in each year of the period). Calculating overspend in this way would assist to ensure that NSPs' expenditure is not

[69] ENA's Response to the MEU Rule Change Proposal, p1.

[70] 2006 TNSP Rule Determination, p99 (Attachment 2 to the December Response).

[71] AER's EBSS Final Decision, p3.

[72] AER's EBSS, p1.

inefficiently reallocated between regulatory years during a regulatory control period to avoid exceeding the allowance in any one year.

An EBSS for capex is the best option for dealing with capex incentive issues

The Businesses consider that:

- an EBSS for capex is the means of strengthening capex incentives that best promotes the NEO and the RPPs as it provides continuous incentives for efficiencies without giving rise to disincentives to incur efficient expenditure; and
- the appropriate process for developing such an EBSS is for the AER to do so under the existing provisions of the Rules.

The reasons for this are outlined further below.

An appropriately designed EBSS can offer continue incentives to NSPs to incur only efficient capex. As noted above, such an EBSS encourages efficiency through financial incentives but removes the need for direct supervision of NSPs' expenditure, thereby avoiding the issues associated with the potential adverse impact on investment of ex post assessments and optimisation of the RAB.

The Businesses also observe that an EBSS for capex complements the opex EBSS, STPIS and DMIS as part of an overall package aimed at delivering better long term outcomes for customers. These incentive schemes are inter-related and require a co-ordinated approach to ensure DNSPs have an incentive to outperform benchmarks for the long term benefit of customers.

The Rules explicitly provide for an EBSS to be developed to cover efficiency gains and losses related to capex.[73] The Businesses consider that an appropriate capex EBSS can be developed under the existing Rules to strengthen incentives to incur efficient capex.

The AER has indicated to the AEMC that in deciding not to apply an EBSS to capex in 2008, its primary concern was that the inclusion of capex could inappropriately incentivise the deferral of capex into future regulatory control periods.[74] The Businesses make three points in response.

First, while the Businesses acknowledge that an incentive to defer capex may exist under a capex EBSS, efficient deferral of capex is in the long term interest of consumers as it lowers the costs of providing network services.

Second, under the existing regulatory framework, an NSP's incentive to defer capex is constrained by reliability standards in complementary incentive schemes. The Businesses acknowledge that capex deferral may have a negative consequence to consumers if it results in lower levels of network service performance. In the current regulatory regime, however, this concern is addressed through the STPIS, which ensures that DNSPs have a strong incentive to maintain (and when feasible improve) network service performance.

In any event, the Businesses submit that the development of a new EBSS for capex will be a complex exercise and the optimal solutions to the issues raised in respect of such a mechanism will

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[73] Clause 6.5.8(b) of the Rules.

[74] Letter from Mr Andrew Reeves, Chairman, AER to Mr John Pierce, Chairman, AEMC dated 2 February 2012, p4.

take time to develop. The Businesses do not consider that this Rule change process is the appropriate forum for this work. The AER has the power under the existing Rules to develop an EBSS for capex, and should do so under those provisions. The precise issues around how the EBSS will operate in practice and how to balance the competing incentives that may arise should be the subject of separate consultation and consideration by the AER, in light of its broader range of incentive schemes.

The Businesses consider that the Rules in their current form best promote the NEO and the RPPs. In particular, the Businesses maintain that any EBSS for capex must be symmetric. As noted in the December Response, the AEMC has previously recognised that 'anything other than a rule framework which provides for the symmetric treatment of expenditure efficiency gains and losses would prevent the incentive mechanisms from achieving its objective of providing even incentives in each year'.[75] While the AER considers that an asymmetric mechanism 'guards against the incentive some other NSPs may have to significantly and inefficiently overspend their capex forecasts to receive the higher return', as outlined above, capex levels are impacted by a range of factors (and not just the regulatory regime). In any event, the AER's concerns may be addressed through other means and, as noted, should be the subject of consultation by the AER in accordance with the distribution consultation procedures.

5.2 ACTUAL OR FORECAST DEPRECIATION

AEMC's initial view

The AEMC accepts that the decision whether to use actual or forecast depreciation to establish opening RAB values impacts on the strength of the capex efficiency incentive.[76] Given the complexities of the issue, however, the AEMC would like to explore in more detail how using actual or forecast depreciation to determine the opening RAB affects an NSP's behaviour.[77]

Businesses' response

The Businesses' response to the following issue for further comment identified in the Directions Paper is set out below and in Appendix A to this response:

Question 9	How does using actual or forecast depreciation to determine the RAB affect a NSP's behaviour?

As noted by the AEMC, a forecast depreciation approach (whereby, for the purposes of the RAB roll forward, depreciation is determined by reference to forecast capex rather than actual capex) has a neutral effect on capex incentives because the depreciation adjustment will be the same regardless of the actual outcome.[78]

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[75] December Response, p90 (citing 2006 TNSP Rule Determination, p96).

[76] Directions Paper, p46.

[77] Directions Paper, p49.

[78] Directions Paper, p48. As noted in Appendix A, the capex efficiency incentives are confined to those arising as a result of finance costs. The risks and rewards of any divergence between actual and forecast capex lie almost entirely with users (i.e. there is not sharing of the benefits/detriments of capex efficiencies/inefficiencies between DNSPs and users).

Calculating depreciation based on actual capex, on the other hand, strengthens an NSP's incentives to incur only efficient capex. The impact of using actual versus forecast depreciation is described in detail in Appendix A.

The AEMC queries whether the decision to apply actual depreciation creates incentives for 'over forecasting' by DNSPs.[79] The argument goes that where DNSPs underspend relative to their forecasts, they benefit if actual depreciation is used to determine opening RAB values because the lower actual depreciation leads to higher regulatory allowances in the next regulatory control period than would otherwise be the case if forecast depreciation is used (as a result of higher RAB values). This, it is said, encourages DNSPs to over forecast expenditure amounts.[80]

The Businesses submit that any argument that applying actual depreciation leads to over forecasting to the detriment of consumers is misplaced because it proceeds on the assumption that excessively high forecasts put forward by DNSPs will result in higher approved annual revenue requirements. This assumption is incorrect. The Rules permit the AER to accept proposed forecasts only to the extent they reasonably reflect the capex criteria.[81] The AER has the power to reject a DNSP's forecast capex where it does not reasonably reflect the capex criteria and substitute forecasts that reflect those criteria.[82] Indeed, the Businesses observe that the AER has substituted its own forecast capex in every distribution and transmission determination under the Rules to date.[83]

Further, while a specific concern is raised that Victorian DNSPs have 'over forecast' capex in the past, this concern fails to recognise that an NSP's actual capex will necessarily be constrained by the allowance it receives in the relevant regulatory decision. Regulated businesses do not have access to an endless pool of capital, and thus they are constrained by the revenue allowed by the regulator (which has historically been lower than the capex forecast put forward by the NSP). It is therefore not surprising that the actual capex incurred is closer to the allowance amount than the forecast amount.

In any event, as recognised by the Tribunal in *Application by United Energy Distribution Pty Limited* [2012] ACompT 1, in a regulated environment it is 'very likely that persistent underspending in relation to forecast capex probably signified efficient and prudent capex on the part of the DNSPs.'[84]

If a DNSP is able to efficiently avoid or defer capex, thereby incurring less capex in a regulatory control period than is forecast in the relevant distribution determination, the RPP in section 7A(3) of the Law (being that a regulated NSP should be provided with effective incentives in order to promote economic efficiency) makes it clear that that outcome should be encouraged.

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[79] Direction Paper, p49.

[80] See *Application by United Energy Distribution Pty Limited* [2012] ACompT 1 at [323].

[81] Clause 6.5.7(c) of the Rules.

[82] Clause 6.12.1(3) of the Rules.

[83] See Table 1 of the December Response (p49).

[84] *Application by United Energy Distribution Pty Limited* [2012] ACompT 1 at [331].

For these reasons, the Businesses strongly support the Rules providing for discretion on the part of the AER to apply forecast or actual depreciation. This is particularly important where no EBSS is applied to capex but is applied to opex. In such circumstances, the efficiency incentives will be imbalanced. This imbalance in the efficiency incentives for opex and capex can be mitigated by the use of an actual depreciation approach in preference to a forecast depreciation approach. This is because, as discussed above and in Appendix A, the use of an actual depreciation approach creates additional capex efficiency incentives not present under a forecast depreciation approach.

5.3 UNCERTAINTY REGIME

AEMC's initial view

While the AER proposed the introduction of capex reopeners and contingent projects into the distribution regulatory regime to address issues arising from the AER's proposed changes in respect of capex and opex allowances and the capex incentive regime, the AEMC has considered whether there is any other justification for changes to the uncertainty regime.[85]

The AEMC's initial view is to support extending capex reopeners and contingent projects to distribution on the basis that setting the regulatory framework to allow recovery of uncontrollable costs should promote efficient investment in electricity services, contributing to the NEO.[86] While the AEMC accepts that distribution projects are likely to be smaller and involve less lead time than transmission projects, the AEMC considers this challenge can be overcome by setting the threshold for contingent projects at an appropriate level.[87] The AEMC has not formed a view as to what the threshold should be but considers there is merit in the AER having discretion to set the contingent project threshold in guidelines.[88]

In relation to pass through events, the AEMC's initial view is that there is benefit in having a materiality threshold which is certain.[89] The AEMC also considers there is benefit in having a mechanism to prevent double recovery of capex allowed in respect of a pass through event (i.e. a provision that provides that where capex is fully recovered by an NSP during a regulatory control period pursuant to a pass through application, the capex should not be rolled into the RAB at the next regulatory determination).[90]

Businesses' response

Capex reopeners and contingent projects

The Businesses remain concerned that the capex reopener and contingent projects provisions are not suitable in the distribution context.

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[85] Directions Paper, p52.

[86] Directions Paper, pp52-53.

[87] Directions Paper, p53.

[88] Directions Paper, p53.

[89] Directions Paper, p53.

[90] Directions Paper, p53.

Regarding capex reopeners, the Businesses observe that the criteria that the AER has to be satisfied of before allowing a capex reopener are extremely wide ranging. It would appear to include, for example, requiring the DNSP to re-justify its entire capex program (and potential opex program to address any trade-off issues), which would require detailed supporting material on par with the supporting material required in a distribution determination process.[91] Even if an appropriate materiality threshold was applied, introducing a capex reopener regime would not promote the NEO or the RPPs as it would impose a significant administrative burden on both the DNSP and the AER.

The Businesses also maintain that contingent project provisions are not suitable in a distribution context. As identified by the SCO at the time Chapter 6 was introduced, whereas transmission networks are made up of a small number of large assets, distribution networks have a large number of smaller assets and require regular investments to facilitate new connections, system augmentation and asset replacement.[92] This has the following implications for a contingent project regime in a distribution context:

- the administrative burden associated with such a regime will be much higher as a larger number of trigger events would need to be specified at the time of the distribution determination and (provided an appropriate materiality threshold is determined[93]) considered throughout the course of the regulatory control period; and
- there is increased risk that efficient capex will not be recovered. As each project must satisfy the requirements under the proposed Rules (in particular, it must result from the defined trigger event and must satisfy the materiality threshold), there is an increased risk that capex will not be recovered in respect of individual projects, even where it is prudent and efficient.

Further, the Businesses observe that it does not appear that merits review will be available in respect of the AER's decisions regarding contingent capex. This increases the risk of regulatory error and thus increases the risk that DNSPs will not be provided with an opportunity to recover efficient capex, contrary to the NEO and the RPPs.

The Businesses therefore contend that, in the distribution context, the existing Rules regarding capex forecasts better promote the NEO and are more with consistent with the RPPs than the introduction of capex reopener and contingent capex provisions.

Pass through events

The AER's proposed introduction of a materiality threshold of 1% of a DNSP's annual revenue requirement for all pass through applications is contrary to the NEO and the RPPs. The RPPs provide that NSPs should be provided with a reasonable opportunity recover their efficient and prudent costs, regardless of whether the costs were foreseeable or not. The materiality threshold

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[91] See December Response, p75.

[92] SCO, *Changes to the National Electricity Rules to establish a national regulatory framework for the economic regulation of electricity distribution, Explanatory Material,* April 2007, p49 (Table 1) (Attachment 51 to the December Response).

[93] The AER's proposed initial threshold of $10 million is too high in the context of distribution and is inconsistent with the current MCE Rule change proposal to apply a distribution regulatory investment text to capex in excess of $5 million: December Response, pp75-76.

proposed by the AER is overly onerous, significantly increasing the risk to DNSPs of costs associated with unanticipated events, which (unless provided for in their regulated revenues) is contrary to the intent of the pass through regime and the RPPs and puts the quality, safety and reliability of supply at risk, contrary to the NEO.

The Businesses submit that a materiality threshold of $1 million would increase the certainty for stakeholders around what is a material event for the purposes of the pass through provisions, and would alleviate the need for the AER to form a view as to what is material in specific instances, meeting the AER's stated concerns with the existing NER provisions. Such a threshold would also avoid the adverse cost recovery consequences of the AER's proposed threshold, thereby promoting the NEO and the RPPs. Further discussion on this issue and the Businesses' alternative Rule change are set out in the December Response.[94]

5.4 RELATED PARTY MARGINS AND CAPITALISATION CHANGES

AEMC's initial view

The AER proposed a Rule change to provide that any amount of related party margins and capitalised overheads must not exceed amounts determined in accordance with how related party margins and capitalised overheads were included in the total forecast capex determined in the distribution determination for the previous regulatory control period.

The AEMC's initial view is that there are issues regarding changes in capitalisation policy by NSPs during a regulatory control period and the solution proposed by the AER may be appropriate.[95] However, the AEMC considers that stronger capex incentives through the EBSS may address this.

The AEMC did not set out an initial position with respect to related party margins.

Businesses' response

The Businesses' response to the following issues for further comment identified in the Directions Paper is set out below:

Question 12	To what extent would stronger capex incentives, through an EBSS for example, deal with incentives for a NSP to inefficiently change its capitalisation policy during a regulatory control period?
Question 13	How, and to what extent, does the incentive for a NSP to overspend or underspend vary depending on whether it uses a related party or not having regard to the other incentives for efficient capex, including the scope for the AER to determine efficient capex at the regulatory determination?
Question 14	To what degree would a parent company of a NSP be better off if related party margins, that are higher than those allowed for by the AER in the regulatory determination, are due to genuine higher costs.

[94] December Response, pp78-82.

[95] Directions Paper, p58.

If the AEMC considers that a Rule change is desirable, the Businesses continue to submit that the Rules should provide for related party margins to be rolled into the RAB provided they are consistent with the framework established in the prior distribution determination.[96]

Similarly, decisions as to the inclusion of overheads in the RAB roll forward should be based on whether they were allocated to capex consistently with the capitalisation policy of the DNSP at the time of the distribution determination.[97] The Businesses observe that the AER will have knowledge of when capitalisation policies are changed as its usual practice is to issue regulatory information notices that request this information during regulatory determination processes.

Regarding capex incentives and the use of related parties, the Businesses observe that the decision to use related parties is driven by the desire to take advantage of the greater potential for cost efficient provision of network, telecommunication and back-office services and to allow NSPs to focus on long term asset ownership and performance. The capex incentive regime does not impact on the decision to use related parties for efficient service provision.

Further, the decision to incur capex is subject to an NSP's rigorous planning criteria and governance documentation, as well as internal approval processes (such as approval by a capital investment committee). Such policies and procedures are designed to ensure that only efficient capex is incurred.

5.5 OTHER INCENTIVE SCHEMES

AEMC's initial view

The AER proposed new Rules to allow it to develop incentive schemes outside those currently provided for in the Rules. The AEMC's initial view is that the Rule change process may be overly burdensome for introducing new incentive schemes and the Rules should allow the AER to develop test schemes before submitting a Rule change proposal.[98]

Businesses' response

The Businesses' response to the following issues for further comment identified in the Directions Paper is set out below:

Question 15	Should the AER be given the power to develop and implement pilot or test incentive schemes within a controlled environment?
Question 16	What limits should be placed on the extent of these schemes?

The Businesses are strong supporters of incentive based regulation and are not opposed to the introduction of balanced, appropriately designed new incentive arrangements.

The Businesses consider that there is some benefit in the AER being given power to develop and implement, or test, incentive schemes. Such a power could be used, for example, to determine if

[96] December Response, pp83-87.

[97] December Response, pp83-87.

[98] Directions Paper, p62.

there is adequate data to properly apply the scheme. The Businesses refer the AEMC to the criteria governing the introduction of new incentive schemes set out in their December Response.[99] Such criteria are necessary to improve clarity, transparency and predictability in the development of new incentive schemes and thus promote the NEO and the RPPs.

The Businesses also agree that constraints on the AER (for example, around the length of the trial) should be included in the Rules. Given the wide variety of incentive schemes that might be trialled under such provisions, the Businesses submit that the limits should be expressed at a principle level, rather than in terms of strict requirements. Rules drafted in such a way would give the AER sufficient flexibility to develop and test different incentive schemes, but ensure that NSPs are not unduly burdened by such trials.

5.6 SHARED ASSETS

AEMC's initial view

The AER proposed changes to the Rules to introduce regulated revenue or control mechanism adjustments where assets in the RAB are used to provide services other than standard control services.

The AEMC accepts that consumers should receive some benefit when assets used to supply regulated services are shared with other services.[100] The AEMC's initial view is that shared assets should be dealt with by way of a mechanism that is flexible, and that principles should be developed to provide guidance on when compensation is permitted and how much that compensation should be.[101]

Businesses' response

The Businesses' response to the following issues for further comment identified in the Directions Paper is set out below:

Question 18	Stakeholders have suggested use of assets for alternative control services should be excluded from the uses for which consumers should receive compensation. Are there any other examples of such uses?
Question 19	What are the appropriate guiding principles [for] allocating compensation arising from sharing assets between regulated and unregulated services?

The Businesses support the AEMC's initial view that principles should be developed to provide guidance on when compensation should be permitted and how much that compensation should be. The Businesses refer to the suggested mandatory criteria outlined in their December Response.[102]

[99] December Response, pp90-91.

[100] Directions Paper, p65.

[101] Directions Paper, p64.

[102] December Response, pp97-98.

In addition, even where criteria governing the AER's discretion are introduced, appropriate measures should be put in place to maintain the transparency and predictability of the regulatory regime. As noted in their December Response,[103] the Businesses consider this could be achieved by requiring the AER to:

- outline its proposed approach to any adjustment in its F&A Paper; and
- calculate any adjustment in accordance with the approach set out in the F&A Paper, unless there are circumstances which justify a departure.

The Businesses agree that the use of assets for alternative control services should be excluded from the uses for which consumers should receive compensation. This would be inappropriate given such services are subject to a separate control mechanism and any changes to the Rules should reflect this.

6 CAPEX AND OPEX ALLOWANCES

This section sets out the Businesses' response to Chapter 3 of the Directions Paper, 'Capex and opex allowances'.

6.1 CAPEX AND OPEX ALLOWANCES FOR NSPS

AEMC's initial view

To address its perceived concern that the existing framework for setting capex and opex deliver 'systematically inflated expenditure forecasts',[104] the AER proposed that the capex and opex criteria should merely require it to determine the total of capex or opex that would represent the efficient capex or opex required by a prudent NSP to achieve the capex or opex objectives.

The AEMC does not accept on the available evidence that the AER has been limited in its assessment of capex and opex proposals.[105] The AEMC's preliminary view is that rising levels of capex and opex are not enough on their own to show a deficiency in the Rules.[106]

The AEMC considers that the policy intent underpinning the existing transmission Rules (i.e. that the AER is not 'at large' in being able to reject forecasts, but must start from the NSP's regulatory proposal and must accept the capex or opex forecast if it is satisfied the total forecast reasonably reflects the capex/opex criteria, taking into account the capex/opex factors) appears to remain appropriate and applicable.[107] The AEMC queries whether changes to the wording of the Rules are required to better reflect this policy intent. For example, the AEMC suggests that the additional constraints in clause 6.12.3(f) of Chapter 6 the Rules, which limit AER to making changes to the

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[103] December Response, p98.

[104] AER Rule Change Proposal, p28.

[105] Directions Paper, pp21-27, 29.

[106] Directions Paper, p25.

[107] Directions Paper, p28. The policy intent is described at pages 15-16.

proposed forecast 'only to the extent necessary' and to substituting forecasts prepared 'on the basis of' the original forecast, are superfluous.[108]

Regarding benchmarking, the AEMC's initial view is that it would be inappropriate if benchmarking did not take into account any circumstances of the NSP.[109] The AEMC considers, however, that there are likely to be some circumstances that would be inappropriate to consider (such as financial decisions of the owner of the NSP).[110]

Businesses' response

Drivers for increases in network costs

The Businesses' response to the following issue for further comment identified in the Directions Paper is set out below:

Question 2	The Commission seeks further evidence on the drivers for increases in network costs, and in particular on the link between capex and opex allowances under the NER and such increases in network costs.

At the outset, while the AEMC has accepted that the AER has not demonstrated that the regulatory framework is a driver of higher network prices, and the current Rules were not in place in the period considered, the Businesses wish to highlight that in a recent study of domestic electricity prices conducted by Ernst & Young, Ernst & Young concluded that network costs have in fact *decreased* in real terms in Victoria between 1996 and 2010.[111] In particular, Ernst & Young found that the distribution network costs (including advanced metering infrastructure costs) per MWh decreased by 20% in real terms over the period.[112] By contrast, Ernst & Young found that non-network costs increased by 31% in real terms over the same period, contributing to an overall increase in the cost of electricity per MWh (in real dollar terms) of 7% from 1996 to 2010.[113]

Similarly, in a separate recent study by Ernst & Young regarding domestic electricity prices in South Australia, Ernst & Young found that network costs decreased in real terms in South Australia between 1998-99 and 2010-11 by 22%.[114] By contrast, Ernst & Young found that non-network costs increased by 86% in real terms over the same period.[115]

Noting the significant increases in electricity prices for domestic customers in South Australia from 1 July 2011, ETSA Utilities requested Ernst & Young to extend their analysis to include the 2011-12

[108] Directions Paper, p29.

[109] Directions Paper, p29.

[110] Directions Paper, p29.

[111] EY Report (Vic), p10.

[112] EY Report (Vic), p10.

[113] EY Report (Vic), p10.

[114] EY Report (SA), p10.

[115] EY Report (SA), p10.

current year. Even when this increase is taken into account, however, Ernst & Young concluded that there has been little change in distribution use of system charges in real terms over the period 1998-99 to 2011-12.[116]

Ernst & Young's analysis of electricity costs by component in Victoria and South Australia is summarised in Figures 2 and 3 below.

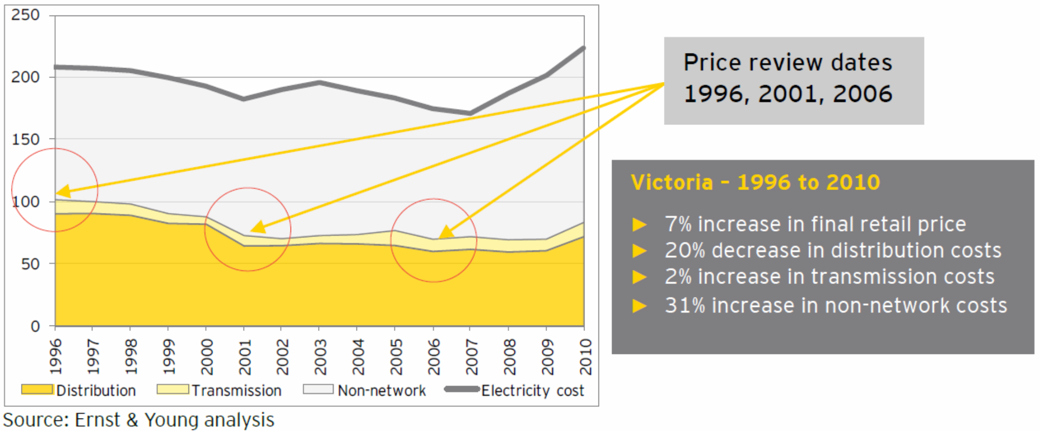

Figure 2: Ernst & Young analysis of Victoria electricity costs by component 1996 to 2010 ($ per MWh, real 2010)

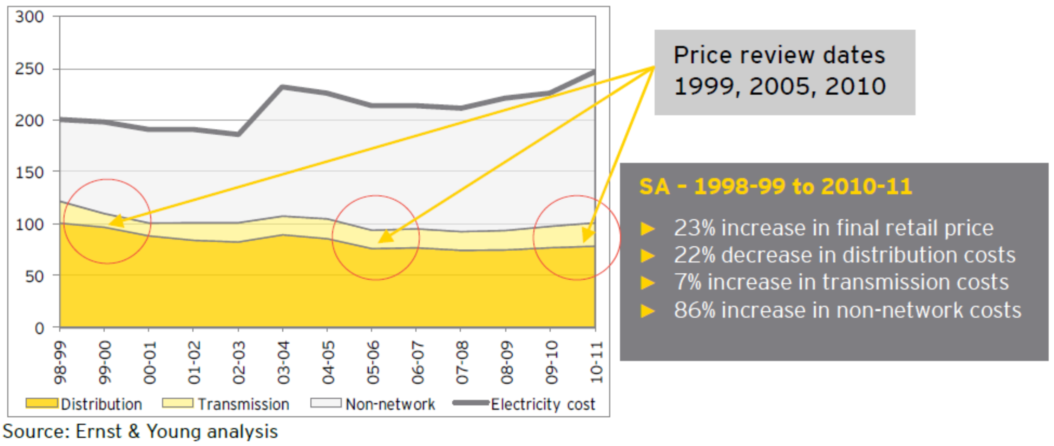

Figure 3: Ernst & Young analysis of South Australian electricity costs by component 1998-99 to 2010-11 ($ per MWh, real 2010)

The Businesses observe that Ernst & Young found that a key driver of the 2% real terms increase in transmission costs was the easement land tax paid by the TNSP in Victoria. If the tax was not paid, Ernst & Young suggest that transmission costs would have fallen significantly, by as much as 18% in real terms between 1996 and 2010.[117] This highlights the significance of factors other than the regulatory regime in considering network costs.

[116] EY Report (SA), p28.

[117] EY Report (Vic), p10.

Figure 2 also shows that network prices are just one component of the end price paid by consumers. Ernst & Young concludes that in 2010 network charges (for both distribution and transmission) contributed only approximately 38% to the end price paid by consumers in Victoria.[118] In South Australia, Ernst & Young concludes that in 2010-11, distribution network costs contributed only around 32% to the end price paid by consumers.[119]

In terms of the drivers of network prices for the current regulatory control periods for each of the Businesses, the main drivers are the cost of capital, expanded capex and opex programs in light of ageing infrastructure and increased demand due to the installation of energy intensive appliances such as air conditioners.

Regarding the distribution determinations for Victorian DNSPs, including CitiPower and Powercor Australia, the AER summarised the position in 2011-15 as follows:[120]

> The overall result for Victoria is positive, with no major increases. In fact some consumers will see slight reductions and others marginal increases on their quarterly bills ...
>
> In a relatively stable environment, past expenditure is a good guide to future needs. However, as required by the regulatory regime, the AER has accepted the need for additional expenditure to replace ageing infrastructure - built in the 1960's and 70's - [to] meet new bushfire safety standards and maintain reliability in the face of growing costs and demand. This is in part due to the growth in energy intensive appliances, like home air conditioners ...
>
> On the whole, the Victorian distributors are efficient operators of a mature and comparatively reliable network. They have had the benefit of a strong economy and strong sales, but we recognise that costs of debt are markedly higher than five years ago when prices were last set[.]

Similarly, in respect of ETSA Utilities (1 July 2010 to 30 June 2015), the AER stated:[121]

> ... More than half of this expanded [capex] program is required to ensure the capacity of the network meets future demand from both new and existing customers, including meeting the continuing growth in peak demand. The load is growing as customers continue to install air conditioners and other appliances. In addition, there is need to address risks associated with ageing assets to maintain reliability for customers. The cost of materials and labour and financing costs are also increase ...
>
> ... ETSA Utilities' operating costs largely relate to network maintenance associated with increased inspections and higher emergency response expenditure forecast due to increasing asset age and growth in the network.
>
> ... A factor underlying the revenue increase is the higher cost of capital of 9.76 per cent, which is 80 basis points higher than the current regulatory period, reflecting current and prospective financial conditions.

The Businesses also refer the AEMC to the analysis of key drivers of network price changes prepared by NERA Economic Consulting for the ENA and submitted in response to the Directions

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[118] EY Report (Vic), p12.

[119] EY Report (SA), p12.

[120] AER, 'AER rejects significant price rises by Victorian electricity distributors' (media release in relation to the Victorian distribution determinations), 29 October 2010: http://www.aer.gov.au/content/index.phtml/itemId/740845/fromItemId/746345.

[121] AER, 'AER's final decision on the South Australian distribution determination for ETSA Utilities' (media release in relation to the South Australia distribution determination), 6 May 2010: http://www.aer.gov.au/content/index.phtml/itemId/736389/fromItemId/746345.

Paper. Regarding capex, that report shows that the major categories of capex contributing to network cost increases are:

- for ETSA Utilities, augmentation to meet peak demand growth and non-network assets (including renewal of major IT systems);
- for CitiPower, new customer connections and augmentation to meet peak demand growth; and
- for Powercor Australia, new customer connections and capex to ensure compliance with environmental, safety and statutory obligations.

This expenditure was the subject of detailed review by the AER and its consultants during the distribution determination process, and was considered prudent and efficient.

The Businesses also note that, given the AER adopts a 'revealed costs' approach to forecasting opex, the drivers of the increases in opex can be observed via an assessment of the AER's opex build-up (including, in particular, the opex step changes accepted by the AER). The 'revealed costs' approach to forecasting opex for a DNSP involves taking actual opex incurred in a particular year (the 'base year') and making various adjustments to that base year to forecast that DNSP's opex in each year of the regulatory control period. The approach is generally adopted where regulated businesses have an incentive to incur an efficient level of expenditure in the base year (e.g. due to the operation of an efficiency carryover mechanism). The adjustments to the base year actual opex usually involve the following:

- The removal of non-recurrent opex and other opex amounts not reflective of efficient opex in the relevant regulatory period.
- The escalation of opex amounts to reflect network growth and growth in the number of customers ('scale' escalation) and the expected increase in input costs ('real cost' escalation).
- The addition of 'step change' and other amounts, which are adjustments made to the 'base year' to provide for an allowance for incremental costs that, while efficient, were not incurred in the base year.

The AER's opex build-up for CitiPower and Powercor Australia is shown in Table 2 below.[122]

[122] The build-up is as shown in Table 7.30 of the AER's final decision regarding the Victorian DNSPs: AER, *Final Decision, Victorian Electricity Distribution Network Service Providers Distribution Determination 2011-2015,* October 2010, p374 (Attachment 21 to December Response).

AER opex build-up[123]	CitiPower		Powercor Australia	
AER base year costs	185.7	81.2%	648.1	81.2%
AER scale escalation	3.9	1.7%	17.7	2.2%
AER real cost escalation	8.7	3.8%	31.7	4.0%
AER step changes[124]	26.4	11.5%	88.9	11.1%
AER debt raising costs	3.9	1.7%	6.6	0.8%
AER other (GSL)	0.1	0.0%	5.5	0.7%
AER total opex	**228.6**		**798.4**	

Table 2: AER opex build-up for CitiPower and Powercor Australia ($m, 2010)

Table 2 shows that for CitiPower and Powercor Australia, the base year opex costs contributed around 81% of the forecast opex allowance for the 2011-15 regulatory control period. The opex step change amounts (including real cost escalation), which made up around 10% of the opex allowance, contributed the largest increase above base year opex.[125] The breakdown of the step change amounts accepted by the AER for CitiPower and Powercor Australia are shown in Table 3 below.

[123] Excludes demand management innovation allowance.

[124] Includes real cost escalation.

[125] AER, *Final Decision, Victorian electricity distribution network service providers, Distribution determination 2011-2015*, October 2010, p374 (Attachment 21 to December Response).

Step Change	Reason for Step Change
Electricity Safety (Electric Line Clearance) Regulations 2010 (CitiPower and Powercor Australia)	Changes in regulation (new Electricity Safety (Electric Line Clearance) Regulations 2010)
Increase in annual levy payable to Energy Safe Victoria (CitiPower and Powercor Australia)	Change in regulation
Insurance (CitiPower and Powercor Australia)	Change in operating environment (increased insurance premiums)
National framework for distribution network planning and expansion (CitiPower and Powercor Australia)	Change in regulation (changes to the National Electricity Rules)
Customer charter (CitiPower and Powercor Australia)	Non–recurrent opex item that was not included in base year opex costs (providing customers with a customer charter as required by the Electricity Distribution Code)
Enhanced customer communications (CitiPower and Powercor Australia)	Change in regulation (changes to the Electricity Distribution Code)
Regulatory submission costs (CitiPower and Powercor Australia)	Non–recurrent opex item (costs of preparing regulatory proposals/submissions)
AER outcomes monitoring and compliance framework (CitiPower and Powercor Australia)	Change in regulatory obligation (changes to AER's outcomes monitoring and compliance requirements)
Tariff class reassignment disputes (CitiPower and Powercor Australia)	Change in regulatory obligation (changes to tariff class assignment and reassignment procedures for direct control services)
West Melbourne Terminal Station demand management program (CitiPower only)	Expenditure for activities not included in base year opex costs (expenditure to ensure the security of the network in areas supplied by West Melbourne Terminal Station)
At risk townships program (Powercor Australia only)	Expenditure for activities not included in base year opex costs (expenditure to reduce bushfire risk in areas identified in the Victorian Government's 'at risk townships' protection plans initiative)

Table 3: Breakdown of CitiPower and Powercor Australia step change amounts[126]

Table 3 demonstrates that the step change amounts almost exclusively related to changes in regulatory obligations. The only two items that are not related to the regulatory environment facing the DNSPs were a specific program proposed by CitiPower to ensure security of supply in areas supplied by the West Melbourne terminal station and a specific program proposed by Powercor Australia to reduce bushfire risk. Similarly, for ETSA Utilities, the single greatest increase in opex above base year opex was due to a change in a regulatory obligation. ETSA Utilities was provided

[126] AER, *Final Decision, Victorian Electricity Distribution Network Service Providers Distribution Determination 2011-2015*, October 2010, Appendix L - Operating Expenditure Step Changes (Attachment 38 to the December Response).

an additional allowance for feed-in tariff payments.[127] This allowance was required as a consequence of the *Electricity (Feed-In Scheme - Solar Systems) Amendment Act 2008* (SA), which meant that ETSA Utilities was required (under the terms of its licence) to allow qualifying generators to feed into the distribution network and receive a credit for doing so.[128] Again the AER conducted an extensive review of this opex (including the step change amounts) and determined that it was prudent and efficient.

Policy intent of the Rules

The Businesses agree with the AEMC that the policy intent regarding the role and power of the AER to test an NSP's forecasts (i.e. that the AER should not be 'at large' in being able to reject a forecast and replace it with its own) remains good regulatory practice. As noted by the AEMC, 'the NSP's regulatory proposal is the AER's starting point and represents the most significant evidentiary consideration for the AER.'[129]

The Businesses submit that the existing framework in Chapter 6 promotes the NEO and the RPPs because, for the reasons outlined in the Businesses' December Response, it strikes the appropriate balance between the risks and costs of market failure.[130]

The Businesses' response to the following issue for further comment identified in the Directions Paper are set out below:

Question 3	Would it be appropriate for the wording of the NER to be clarified to better reflect the policy intent?

While the additional words that appear in Chapter 6 are described in the Directions Paper as 'superfluous', removing the constraints may create uncertainty as to the application of the existing case law and the approach of the AER in applying the provisions going forward (i.e. it may decrease the predictability of the decisions). The Businesses thus consider that maintaining the existing provisions is consistent with the AEMC's policy intent and would better promote the NEO and the RPPs, for the reasons outlined in their December Response.[131]

Benchmarking

The Businesses' response to the following issue for further comment identified in the Directions Paper is set out below:

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[127] AER, *Final decision, South Australia distribution determination 2010-11 to 2014-15*, May 2010, pp133-135 (Attachment 19 to December Response). The allowance constituted around 5% of the AER's total opex allowance.

[128] AER, *Draft decision, South Australia Draft distribution determination 2010-11 to 2014-15*, 25 November 2009, p242 (Attachment 39 to December Response).

[129] Directions Paper, p16.

[130] December Response, pp45-54.

[131] December Response, pp45-54.

Question 4	What circumstances of the NSP should the AER be required to take into account when benchmarking?

The Businesses strongly support the AEMC's view that it would be inappropriate if benchmarking did not take into account any circumstances of the NSP. The Businesses refer to the submissions in their December Response regarding the AER's proposed removal of the words 'in the circumstances of the relevant [NSP]'.[132] In short, requiring the AER take into account the circumstances of the relevant NSP is critical to ensuring that the AER considers the operating environment of the relevant NSP, this operating environment being the key determinant of the cost structure of the NSP.

The Tribunal has recognised the importance of taking the circumstances of regulated businesses into account in ensuring that benchmark comparisons are valid. For example, in rejecting Telstra's proposed use of international benchmarking in support of its proposed charges for unconditioned local loop services (ULLS) in *Telstra Corporation Ltd (No 3)* [2007] ACompT 3, the Tribunal stated:[133]

> We are not satisfied that Telstra has provided sufficient evidence to support the use of international benchmarking. Although Telstra's benchmarking report contains summary information regarding ULLS regulation in other jurisdictions, in order to place any reliance upon the international benchmarking analysis it would be necessary to know much more about the regulatory framework, the cost of capital and the price structures employed in other jurisdictions. The summary tables provided by Telstra did not provide us with sufficient information to determine whether the benchmarks were reasonable comparators for Telstra's ULLS monthly charges. In addition, we are not satisfied that the adjustment of the benchmark ULLS charges only for purchasing power parity and line density takes into account all the adjustments that need to be made to the benchmark ULLS charges for them to be reasonable comparators. **The costs of providing the ULLS (or similar services) can vary between jurisdictions for a myriad of reasons and we need to be careful when comparing cost estimates across different jurisdictions. The benchmarking analysis conducted by Telstra only makes adjustments for a small number of possible differences that might exist to generate cost differences in the surveyed jurisdictions. Telstra has not provided us with sufficient evidence to further satisfy us that the cost estimates from other jurisdictions considered by Telstra in its international survey do not require further adjustment before can rely on them.**
>
> [Emphasis added in bold.]

In the context of electricity distribution, a broad range of factors are relevant to a benchmarking exercise, for example: the applicable reliability and service standards, the age the network, density of the customer base, the customers' load profile, other characteristics of the customer base (including the mix of customers, e.g. industrial v domestic), topography, climate, input prices that vary by location (e.g. labour) and so on.

The AER has accepted that a broad range of matters should be taken into account in conducting benchmarking. For instance, upon concluding that the level of capex and opex of Victorian DNSPs is broadly below the level of comparable DNSPs (New South Wales and Queensland), the AER stated:[134]

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[132] December Response, pp57-58.

[133] *Telstra Corporation Ltd (No 3)* [2007] ACompT 3 at [382].

[134] AER, *Final Decision - appendices, Victorian electricity distribution network service providers, Distribution determination 2011-2015,* October 2010, Appendix H, pp104, 112 (Attachment 38 to December Response).

> As the data used in this analysis has not been corrected for differences that exist in the regulatory environment historically, asset classification, network maturity and geographical factors between jurisdictions, caution must be used when applying this analysis more broadly.

Similarly, in its Final Decision regarding ETSA Utilities, the AER stated:[135]

> Benchmarking techniques require operating conditions to be accounted for so as to make firms directly comparable. Australian electricity DNSPs face a diverse range of operating environments, and have widely varied customer bases, jurisdictional requirements and cost drivers. The AER does not yet have access to the depth of data required to perform detailed benchmarking analysis that will normalise firms to make them directly comparable.

The Businesses observe that the Tribunal has also accepted the significance of taking the network characteristics of the DNSP into account in conducting benchmarking in the electricity distribution context. In *Application by United Energy Distribution Pty Limited* [2012] ACompT 1, the Tribunal accepted CitiPower's and Powercor Australia's submissions that the AER erred in failing to take proper account of the differences between the networks of the Victorian DNSPs in assessing the vegetation management step change amounts proposed by CitiPower and Powercor Australia.[136] Vegetation management involves the clearing of vegetation from around power lines and service lines to ensure compliance with minimum clearance standards (codified in legislation). CitiPower and Powercor Australia submitted to the Tribunal that a range of differences between the networks impacted on vegetation management costs, including the size of the network, average span length (i.e. the average distance between electricity poles), degree and density of the vegetation per span, growth conditions, species, maturity and vegetation around the network, travel costs associated with getting to the various points on the network, site access costs, traffic management costs, clean up requirements, sensitivity of the owners/occupiers of the land to aggressive cutting and the incidence of service lines crossing property boundaries and service lines that are partially located on road reserves on public land (both of which mean that the relevant DNSP is responsible for clearing the lines).

Under the current Rules, the AER has the ability to perform appropriate benchmarking. Clauses 6.5.6(e)(4) and 6.5.7(e)(4) of the Rules provide that, in determining whether forecast expenditure reasonably reflects the capex/opex criteria, the AER is required to have regard to the benchmark opex/capex that would be incurred by an efficient DNSP over the regulatory control period. The capex and opex criteria are:[137]

- the efficient costs of achieving the capex/opex objectives;
- the costs that a prudent operator in the circumstances of the DNSP would require to achieve the objectives; and
- a realistic expectation of the demand forecast and cost inputs required to achieve the objectives.

Given the lack of standardised and appropriate data, the AER concluded that it could not establish revenue allowances based primarily on the outcome of comparative benchmarking: p99.

[135] AER, *Final Decision, South Australia distribution determination, 2010-11 to 2014-15*, May 2010, p367 (Attachment 19 to December Response).

[136] *Application by United Energy Distribution Pty Limited* [2012] ACompT 1 at [666]-[667].

[137] Clauses 6.5.6(c) and 6.5.7(c) of the Rules.

The inquiry to which benchmarking relates is thus whether the costs proposed reflect the efficient costs that a prudent operator *in the circumstances of the relevant DNSP* would require. The AER is not required to have regard to *all* circumstances of the relevant DNSP. Rather, the AER need only have regard to the circumstances of the individual NSP that might impact on the level of costs that an efficient DNSP would need to incur in order to meet the capex/opex objectives. The AER is not, for example, required to adjust for the financial decisions of the NSP.

The Businesses consider that it would be difficult to set out in the Rules a comprehensive list of the circumstances to which the AER must have regard in conducting a benchmarking exercise. The factors identified by the AER in the Victorian and South Australian final determinations, and the specific matters identified by CitiPower and Powercor Australia as relevant to a comparison of vegetation management expenditure in the Victorian review proceedings, as outlined above, demonstrate the broad range of matters that are potentially relevant.

6.2 CAPEX AND OPEX FACTORS

AEMC's initial view

The AER argued that the capex and opex factors should be neither mandatory nor exhaustive, and that the requirements to consider demand forecasts and cost inputs should be included as factors (i.e. and removed as capex and opex criteria to which the AER must have regard). Regarding the capex/opex factors that relate to matters of procedure (including the factor requiring the AER to consider analysis undertaken by the AER and published before the final determination), the AER proposed moving these out of the factors and into other parts of Rules. The AER also proposed removing the reference to the publication of the analysis.

The AEMC considers that, to balance the competing considerations of procedural fairness and transparency on the one hand and the need for the AER to adhere to strict time frames on the other, the Rules should be clarified to make it clear that there is an obligation on the AER to publish its analysis with its draft and final determinations, but no obligation to do so before this.[138]

The AEMC's initial view is that it would then be appropriate to move the 'procedural' factors in the way proposed by the AER.[139] The AEMC considers that it would be also appropriate to clarify that the factors are non-exhaustive but that the listed factors should remain mandatory considerations.[140]

The AEMC's initial view regarding the criteria of demand forecasts and cost inputs is that they more significant and should remain as mandatory capex and opex 'criteria'.[141]

Businesses' response

As noted in the December Response,[142] an obligation for the AER to publish any analysis undertaken by or for it for the purposes of a distribution determination prior to that determination being made

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[138] Directions Paper, pp32-33.

[139] Directions Paper, p33.

[140] Directions Paper, p33.

[141] Directions Paper, p33.

[142] December Response, pp60-62.

promotes the NEO and the RPPs as it mitigates the risk of regulatory error. It also facilitates an assessment of whether there has been any regulatory error in the making of that determination prior to review proceedings being commenced, thereby potentially avoiding review proceedings.

The Businesses observe that a requirement to consult on analysis prior to it being relied upon in a determination would not interrupt the regulatory process or make it unworkable for the AER as posited by the AEMC. The Businesses would be surprised if the AER did not itself progress draft reports with its consultants or prepare early versions of models prior to a determination being published. Consultation with stakeholders could proceed concurrently with the AER's internal consideration of the draft reports/models. Such an approach would promote one of the objectives identified by the AEMC for the regulatory process, namely, 'the regulatory determination process should encourage dialogue between the AER and NSPs to establish a common understanding of the issues'.[143]

The Businesses agree with the AEMC's initial view that the criteria of demand forecasts and cost inputs should remain 'criteria' but that it would be appropriate to move the procedural capex and opex factors (subject to the requirement to publish that analysis being clarified).

Consistent with their December Response,[144] the Businesses also agree that the AER should be required to have regard to the each of the listed capex/opex factors in considering capex and opex forecasts. As noted in that Response, the establishment of an obligation, rather than a discretion, for the AER to have regard to the capex/opex factors was the result of a deliberate policy decision by the AEMC and is an important element of the Rule provisions designed to constrain and guide the AER's exercise of judgment in assessing expenditure forecasts.[145]

7 REGULATORY DETERMINATION PROCESS

This section sets out the Businesses' response to Chapter 7 of the Directions Paper, 'Regulatory determination process'.

7.1 NSP SUBMISSIONS RECEIVED DURING A REGULATORY DETERMINATION

AEMC's initial view

The AER proposed placing limitations on NSP submissions to address its perceived concern that NSPs are undermining the process by providing material that should be part of an initial or revised regulatory proposal later in the process in the form of submissions. The AEMC will consider the overall regulatory process with a view to achieving the following objectives:[146]

- the AER should have enough time to scrutinise material provided by an NSP in its initial and revised regulatory proposals, including a clear period of time to consider all relevant and significant material submitted during a regulatory determination process;

[143] Directions Paper, p130.

[144] December Response, pp58-59.

[145] December Response, p59.

[146] Directions Paper, p130.

- the regulatory determination process should provide reasonable opportunity for an NSP and other stakeholders to comment on and scrutinise material submitted by each party during the regulatory determination process that is on equal footing;
- NSPs should have sufficient time to prepare their revised regulatory proposals and should submit as much relevant information as possible in their proposals;
- in circumstances where restriction is imposed on the content of the revised regulatory proposal the Rules should not permit this restriction to be circumvented through the use of submissions; and
- the regulatory determination process should encourage dialogue between the AER and NSPs to establish a common understanding of the issues.

The AEMC will consider options including creating a new consultation step, extending the period for NSPs to submit revised regulatory proposals, commencing the regulatory determination process earlier, delaying the publication of the final determination until a specified number of days after the last material submissions is received and restricting the scope of NSP submissions.[147]

Businesses' response

The Businesses' response to the following issues for further comment identified in the Directions Paper is set out below:

Question 36	Which option(s) would be the best way of addressing problems with the regulatory determination process?
Question 37	Are there any other options that could address the issue of providing adequate time for consultation and assessment during the regulatory determination process?

The Businesses continue to reject the extent of the problem as perceived by the AER and refer to the submissions in this regard in their December Response.[148]

Nonetheless, the Businesses agree that a robust consultation process is desirable as it reduces the potential for regulatory error and acknowledge that improvements to the current regulatory process can be made.

While the Businesses consider that material that is relevant to the AER's determination should be taken into account (regardless of when it is submitted in the process),[149] the Businesses strongly reject the suggestion of delaying the publication of the final determination until after a specified number of days after the last material submission is received. Such a proposal would be unworkable in practice and would introduce unacceptable uncertainty as to the timing of the AER's final determination. For example, whether or not stakeholder submissions are 'material' would be the subject of AER assessment and the circumstances in which the AER would extend the determination process may not be clear to the NSP to whom the determination applies.

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[147] Directions Paper, p130.

[148] December Response, pp162-165.

[149] See December Response, pp173-175.

In addition, any delay on the part of the AER in making the final determination is likely to have flow on effects for the finalisation of distribution tariffs. Clause 6.18.2(a) of the Rules requires DNSPs to submit their pricing proposals to the AER for the first year of the regulatory control period 15 business days after the publication of the AER's distribution determination. Presently, the AER is required to make a final determination no later than two months before the commencement of the regulatory control period.[150] A delay of longer than one or two weeks may mean that the AER does not have sufficient time to approve a pricing proposal prior to the commencement of the regulatory control period.[151] This may result in price shock to consumers as any increase in the DNSP's revenue requirements would need to be recovered over four years rather than five.

Further, the Businesses observe that it is not necessary to enshrine a 'clear period' in the Rules. As the Tribunal has observed, '[a] line must be drawn by the AER in its engagement with a DNSP, else it fails to meet the deadlines imposed on it.'[152]

The Businesses continue to support the alternative Rule change proposal set out in their December Response. In particular, the Businesses maintain that a more robust consultation (which would promote the NEO and be consistent with the RPPs) would:

- include a cross-submissions process to allow NSPs and other stakeholders to make submissions on interested party submissions; and
- provide for the submission of revised regulatory proposals within 40 business days of the draft determination (rather than 30 businesses days).

The Businesses accept that a short extension to the regulatory review process (by commencing the regulatory determination earlier) may improve the regulatory process by allowing for earlier engagement between the AER and NSPs. The Businesses observe, however, that such earlier engagement would not make it easier for the Businesses to submit a revised regulatory proposal to the AER within 30 business days. This is because, in the Businesses' experience, consulting with the AER prior to a draft determination does not necessarily provide an early indication of the AER's assessment of a particular issue. Further, draft determinations canvass a wide range of issues[153] and not all issues will be the subject of consultation prior to the publishing of the draft determination. Finally, a period of longer than 30 business days is required for the preparation of a revised regulatory proposal in circumstances where (as is often the case) external expertise is required to address the issues raised by the AER.

7.2 NSP PROPOSALS CLAIMING CONFIDENTIALITY

AEMC's initial view

The AER proposed amendments to the Rules to address concerns about wide-ranging confidentiality claims.

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[150] Clause 6.11.2 of the Rules.

[151] The AER approves pricing proposals under clause 6.18.8 of the Rules.

[152] *Application by EnergyAustralia* [2009] ACompT 8 at [257] (Attachment 15 to the December Response).

[153] The Businesses refer to the summary of the volume of material published with the draft determinations in respect of them in their December Response, pp162-163.

The AEMC considers it is important that the probative value of as much of an NSP's material is able to be tested with stakeholders.[154] The AEMC considers that if the issue with the AER's existing powers under the Law is not having sufficient time to apply the powers, then it may be appropriate to consider an extension to the time period to allow sufficient time to assess confidentiality claims. The AEMC will seek to ensure that the Rules provide for as much scrutiny as possible of initial and revised regulatory proposals, while upholding legitimate claims of confidentiality by NSPs.[155]

Businesses' response

The Businesses' response to the following issues for further comment identified in the Directions Paper is set out below:

Question 38	Should the AER be given more time to consider confidentiality claims in initial and revised regulatory proposals?
Question 39	Should the NER be clarified to reflect the NEL and/or common law position with respect to the AER's ability to give weight to confidentiality claims in initial and revised regulatory proposals?
Question 40	Alternatively, are there any other additional ways to address confidentiality claims in initial and revised regulatory proposals that are not currently available under the NER?

As noted in their December Response, the Businesses claimed confidentiality over only a small amount of information in their respective distribution determination processes.[156]

The Businesses observe that the AER is not constrained with respect to the time it can take to assess confidentiality claims under the Rules (see clauses 6.9.3, 6.10.3(e) and 6.14(c) of the Rules). The time constraints appear to arise only in the sense of the fixed timeframe for the making of a distribution determination. Any extension of the time for the making of a determination will assist to alleviate these time pressures. The AER has also acknowledged its internal processes can be improved for the purposes of making reliance on its existing powers to test confidential information more administratively feasible.[157]

The Businesses therefore maintain that the existing framework strikes the correct balance between offering protection to NSPs submitting confidential information to the AER, while at the same time allowing for transparency of decision making, and no change to the Rules is necessary.[158]

[154] Directions Paper, p135.

[155] Directions Paper, p136.

[156] December Response, p176.

[157] Letter from Mr Andrew Reeves, Chairman, AER to Mr John Pierce, Chairman, AEMC dated 2 February 2012, p7.

[158] See December Response, pp176-179.

7.3 FRAMEWORK AND APPROACH STAGE

AEMC's initial view

The AEMC's initial view is that an F&A Paper should be optional, that incentives schemes should continue to be addressed in the Paper and that it may be appropriate to also address the proposed mechanism for shared distribution assets.[159] The AEMC seeks comments on the appropriate mechanism to trigger the publication of an F&A Paper, including whether stakeholders other than NSPs should have the ability to trigger an F&A Paper.[160]

The AEMC considers that the AER's proposed 'unforseen circumstances' trigger for changes to the control mechanism or service classification (i.e. between the F&A Paper and the distribution determination) appears to be appropriate.[161]

Businesses' response

The Businesses' response to the following issues for further comment identified in the Directions Paper is set out below:

Question 42	Is it appropriate if a service classification or control mechanism can only be amended at the time of an AER final regulatory determination for circumstances that were not reasonably foreseeable at the time of the framework and approach paper?
Question 43	Is there likely to be sufficient time for an NSP to accommodate an adjustment to a control mechanism in the AER draft regulatory determination?

The Businesses accept the AEMC's initial views as to the matters to be addressed in the F&A Paper (i.e. that the F&A Paper should continue to set out the approach to the classification of distribution services, the application of the STPIS, EBSS and DMIS and any other matters the AER thinks fit). In addition, as discussed in their December Response, the Businesses submit that the F&A Paper should also cover the framework for the treatment of shared assets.[162]

While the Businesses submitted in their December Response that making an F&A Paper optional would address the AER's concern as to the inefficiencies associated with the publication of an F&A Paper,[163] in light of the AEMC's position regarding the matters to be covered in the F&A Paper, the Businesses consider it would be administratively simpler if the current position in the Rules was maintained (i.e. an F&A Paper must be published prior to each regulatory determination). This would avoid complications associated with 'triggering' the publication of an F&A Paper and would remove the uncertainty around whether an F&A Paper process will be conducted for any given regulatory control period. The Businesses observe that to the extent no

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[159] Directions Paper, p142.

[160] Directions Paper, p141.

[161] Directions Paper, p142.

[162] December Response, pp98-99, 183-184.

[163] December Response, p184.

party proposed a departure from the approach adopted in the previous regulatory control period, the consultation process would be streamlined.

In the event the AEMC determines that the F&A Paper should be optional, the Businesses support the triggers for the publication of an F&A Paper set out in their December Response.[164] The Businesses do not consider it necessary for stakeholders other than the AER and the relevant NSP to have the ability to trigger an F&A Paper. The AER can be expected, in the interests of good regulatory practice, to consider the views of stakeholders as to whether the F&A Paper process is required before determining whether or not to trigger the process and no separate power on the part of these stakeholders is required.

As noted in their December Response,[165] the Businesses agree that the AER should have some flexibility to revisit the formulaic expression of the control mechanism of the determination stage (indeed, the Businesses consider that the AER already has power under the existing Rules to make such amendments). However, to the extent the AEMC seeks to amend the existing provisions, the Businesses submit that, in contrast to the AER's proposal, there needs to continue to be a 'locking in' of the type of control mechanism that will be applied in the determination prior to the lodging of the regulatory proposal.

A change to the control mechanism occurring after DNSPs have submitted their regulatory proposals (i.e. as a result of the AER's draft determination) would impose a prohibitive administrative burden on them, particularly given the tight timeframes for submitting the revised regulatory proposal. Further, and perhaps more significantly, NSPs would have limited opportunity to reflect upon and properly understand the implications of the mechanism. Any innovative, complex control mechanism can take a DNSP and its management a long time to fully understand. DNSPs need sufficient time to consider and reflect upon any new control mechanism to ensure that any unintended and perverse outcomes that may result from the introduction of that mechanism are avoided and to properly consider the impact of the type of the control mechanism on other parts of their regulatory proposals.[166] The amendments at the draft determination stage should be limited to the formulaic expression of the control mechanism.

As noted, the Businesses consider the control mechanism should be 'locked in' at the F&A Paper stage, subject only to amendments to the formulaic expression of the control mechanism at the determination stage. The Businesses also consider that a considerable of degree of certainty is required in respect of the AER's framework for the treatment of shared assets but that, again, minor amendments to the framework should be permitted at the distribution determination stage.

Regarding service classification on the other hand, the Businesses consider that a broader scope to amend the service classification set out in the F&A Paper may be appropriate. The AER's proposed 'unforeseen circumstances' test for departing from the service classification in the F&A Paper may be too narrow. It is not clear, for example, that certain re-classifications accepted by the AER in the Businesses' distribution determinations would be permitted under an 'unforeseen circumstances' test. In particular, for CitiPower and Powercor Australia:

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[164] December Response, pp181-188.

[165] December Response, p181.

[166] See, for example, the discussion of the introduction of a new control mechanism by ESCOSA: December Response, pp182-183.

- The AER accepted that 'location of underground cables' should be classified as a standard control service (rather than an alternative control service) given the cost of regulating the service separately as an alternative control service would outweigh the benefits of regulating the service in this manner.[167]

- The AER accepted the classification of 'meter investigation', 'special reading' and 'PV installation' as alternative control services in circumstances where there had been no classification of these services at the F&A Paper stage.

Similarly, the AER accepted the classification of additional services by ETSA Utilities at the distribution determination stage (which services had not been classified at the F&A Paper stage).[168]

While there were 'good reasons' for the departure from the F&A Paper, it is not clear that these changes would be permitted under the AER's proposed 'unforeseen circumstances' test. This could result in inefficiencies and/or NSPs not being provided with the reasonable opportunity to recover efficient costs. The Businesses therefore consider that the existing test (namely, the service classification in the F&A Paper can be departed from where there are 'good reasons' for doing so), is likely to better promote the NEO and the RPPs in respect of service classification. At a minimum, the Businesses request that, in making any Rule change in this regard (and regardless of the test to be applied), the AEMC clarify that any services not classified at the F&A Paper stage can be classified at the distribution determination stage.

7.4 MATERIAL ERRORS

AEMC's initial view

The AEMC does not accept the AER's proposal to expand the circumstances for revoking and substituting determinations. The AEMC considers that the tightly defined scope for correcting for errors in the AER's distribution determinations should be maintained.[169] The AEMC also agrees with NSPs that, while it is not clear how amending and substituting regulatory determinations would differ in practice, it will impact unfavourably on the availability of merits review.[170]

Businesses' response

The Businesses support the AEMC's initial position, for the reasons outlined in their December Response.[171]

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[167] AER, *Draft decision, Victorian electricity distribution network service providers, Distribution determination 2011-2015,* June 2010, p25 (Attachment 59 to the December Response).

[168] AER, *Draft decision, South Australia Draft distribution determination 2010-11 to 2014-15,* 25 November 2009, pp20-22 (Attachment 39 to the December Response).

[169] Directions Paper, p147.

[170] Directions Paper, p147.

[171] December Response, pp189-192.

7.5 TIMEFRAMES FOR COST PASS THROUGH, CONTINGENCY PROJECTS AND CAPEX REOPENERS

AEMC's initial view

The AER proposed a 40 business day period to make decisions on cost pass throughs, contingency projects and capex reopeners, which can be extended by an additional maximum period of 60 business days for complex applications. The AEMC's initial view is that a stop the clock mechanism should be explored further for addressing complex pass through and capex reopener applications.[172] The AEMC does not consider that it should be applied to contingent project applications (as it is unclear complex circumstances could arise for these applications).[173]

Businesses' response

The Businesses' response to the following issue for further comment identified in the Directions Paper is set out below:

Question 46	What should be the approach for addressing complex cost pass through, capex reopener or contingent applications? Is the "stop the clock" mechanism appropriate for each type of application?

As noted in section 5.3 above, the Businesses do not consider contingency projects and capex reopeners are appropriate in the distribution context.

Regarding the cost pass through provisions, the Businesses agree that a change in the Rules to allow extended periods within which to consult and gather information to assess complex applications is required. The Businesses refer to the 'stop the clock' mechanism outlined in their December Response.[174] Further to that Response, the Businesses agree with the AEMC's suggestion[175] that a notice of intent for cost pass through applications (e.g. where an application is contingent on the completion of an external inquiry) might promote the NEO and RPPs. Such a mechanism would permit NSPs to arrive at a proper understanding of the cost implications of cost pass through events before submitting an application and thereby allow for more accurate forecasts to be submitted with the cost pass through application, streamlining the AER's assessment process.

[172] Directions Paper, pp150-151.

[173] Directions Paper, p151.

[174] December Response, pp196-199.

[175] Directions Paper, p150.

APPENDIX A - ACTUAL V FORECAST DEPRECIATION

Revenue implications of actual versus forecast depreciation

A divergence between the amount that the AER has allowed as forecast capex in a regulatory control period, and the actual capex incurred by the DNSP in that regulatory control period, has two principal effects on that DNSP's revenues.

First, clause S6.2.1(e)(3) of the Rules requires that the opening RAB value for the next regulatory control period only reflect *actual*, and not *forecast*, capex. Thus, if a DNSP is able to reduce its capex below the amount allowed by the AER in the relevant regulatory control period (e.g., 2011-15), the DNSP’s opening RAB for the next regulatory control period (e.g., 2016-20) will reflect those efficiencies. That is to say, only the reduced actual capex incurred in the relevant regulatory control period will be rolled in to the opening RAB for the next regulatory control period, with the result that the RAB for that next period will reflect an amount of capex in the relevant regulatory control period below what it would have been had the DNSP’s capex equalled or exceeded its forecast capex.

This may be demonstrated by the following example (leaving aside, for the moment, the issue of depreciation):[176]

	Figures used in calculation of revenue requirements for 2011-15	Figures used in calculation of opening RAB for 2016-20
2011 opening RAB	1000	1000
Capex during 2011-15	500 (forecast)	400 (actual)
2016 opening RAB	1,500 (forecast)	1,400 (actual)

In the example above, the DNSP has incurred capex in the 2011-15 regulatory control period that is 100 less than was forecast for that period (its actual capex during the period was 400, rather than 500 as forecast by the AER).

This 'underspend' in capex in the 2011-15 regulatory control period has the effect of reducing the DNSP’s 1 January 2016 opening RAB value for the next period from 1,500 to 1,400. Given that the DNSP’s annual revenue requirement building blocks in the 2016-20 regulatory control period for return on capital and depreciation are calculated by reference to the opening RAB for that regulatory control period, the lower the RAB is as at 1 January 2016, the lower the annual revenue requirements will be for the 2016-20 regulatory control period. Lower annual revenue requirements, will, all other things being equal, result in lower prices for distribution network users in that period.

The implications of actual capex for a regulatory control period being less than forecast for the RAB pursuant to clause S6.2.1(e)(3) may have an impact on a DNSP’s annual revenue requirements (and therefore prices) which extend far beyond the next regulatory control period. If those assets are

[176] In this Appendix, for reasons of simplicity, the issue of indexation for inflation will also be put to one side by assuming zero inflation.

‘long life’ assets (e.g., 50 years or more), then the capex 'underspend' will result in the DNSP’s annual revenue requirements being reduced for potentially *many* regulatory control periods.

Conversely, if a DNSP incurs capex during the regulatory control period in excess of the amount that the AER allowed as forecast capex for the period, then the RAB will be adjusted upwards at the end of the regulatory control period, resulting in (all other things being equal) increased building block values for return on capital and depreciation, and higher prices for potentially many future regulatory control periods.

This may be demonstrated by the following example (leaving aside, for the moment, the issue of depreciation):

	Figures used in calculation of revenue requirements for 2011-15	**Figures used in calculation of opening RAB for 2016-20**
2011 opening RAB	1000	1000
Capex during 2011-15	500 (forecast)	600 (actual)
2016 opening RAB	1,500 (forecast)	1,600 (actual)

In this example, the DNSP has ‘overspent’ on capital in the 2011-15 regulatory control period. Thus, the DNSP’s opening RAB value as at 1 January 2016 is 1,600 (rather than 1,500), which translates (all other things being equal) into higher annual revenue requirements in the 2016-20 regulatory control period.

The second effect of a divergence between the amount that the AER allowed as forecast capex in a regulatory control period and the DNSP’s actual capex in that regulatory control period arises under clause S6. 2.1(e)(5) of the Rules.

Clause S6.2.1(e)(5) requires the value of the RAB for a distribution system as at the beginning of the first regulatory year of a regulatory control period to be calculated by reducing the previous value of the RAB by the amount of depreciation of the RAB during the previous regulatory control period 'calculated in accordance with the distribution determination for that period'.

For the purposes of making that adjustment, clause 6.12.1(18) of the Rules requires the AER to decide, as a constituent decision on which its distribution determination for a regulatory control period is predicated, whether this depreciation adjustment in determining the RAB value at the commencement of the next regulatory control period is to be based on actual or forecast capex.

The AER’s decision under clause 6.12.1(18) of the Rules has no impact on the calculation of the depreciation building block in a DNSP’s annual revenue requirements *within* a regulatory control period; the DNSP’s annual revenue requirements within a regulatory control period are determined by reference to depreciation on forecast capex *only*.

However, the AER’s decision under clause 6.12.1(18) of the Rules will have an impact on the DNSP’s annual revenue requirements (and therefore prices) in the *next* regulatory control period, because that constituent decision has an impact on the amount by which the DNSP’s opening RAB is adjusted pursuant to clause S6.2.1(e)(5).

If a DNSP is able to realise efficiencies by reducing its capex below the amount allowed by the AER as forecast capex in the relevant regulatory control period, then its actual depreciation on capex will be lower than depreciation calculated by reference to its forecast capex. Thus, if forecast depreciation were to be used for the purpose of making the depreciation adjustment in determining the opening RAB value for the next regulatory control period prescribed by clause S6.2.1(e)(5), the DNSP's opening RAB value in the next regulatory control period would be reduced by depreciation calculated by reference to capex that it did not incur.

The converse would apply if the DNSP incurs inefficient capex during the regulatory control period, with the result that its capex in the period is in excess of the amount that the AER allowed as forecast capex for the period. Were the depreciation adjustment under clause S6.2.1(e)(5) to be calculated by reference to forecast capex, depreciation for the purposes of calculating the opening RAB value for the next regulatory control period would be lower than it would have been had depreciation been calculated by reference to actual capex (actual capex being higher than forecast capex). Thus, the opening RAB value for the next regulatory control period would be higher than it would have been, had actual depreciation been used to calculate the opening RAB value (and, all other things being equal, the DNSP's annual revenue requirements and prices will also be higher).

How choice of depreciation methodology creates incentives – Depreciation based on forecast capex

Under a forecast depreciation approach, if the DNSP achieves efficiencies in its capex for the 2011-15 regulatory control period, such that its capex falls below the forecast capex allowed by the AER in its distribution determination for that period, the DNSP receives a benefit from not having to finance the avoided capex. Thus, under a forecast depreciation approach, the DNSP receives a benefit referable to avoided finance costs in 2011-15 regulatory control period in respect of the capex 'underspend' in that period that operates as an incentive for capex efficiency.

The DNSP's annual revenue requirements for the 2011-15 regulatory control period include a depreciation allowance on the higher, forecast, capex and, thus, on the avoided capex. However, under a forecast depreciation approach, at the end of the 2011-15 regulatory control period, the depreciation adjustment made in determining the opening RAB value for the 2016-20 regulatory control period pursuant to clause S6.2.1(e)(3) includes depreciation for 2011-15 on the avoided capex, as well as depreciation for the period on the capex the DNSP has *actually* incurred. Thus, under a forecast depreciation approach, the return of capital the DNSP receives during the 2011-15 regulatory control period is removed from the opening RAB value for the 2016-20 period.

Similarly, under a forecast depreciation approach, if the DNSP is not able to achieve efficiencies in its capex during the 2011-15 regulatory control period, and instead expends more than the forecast capex allowed to that DNSP by the AER in its distribution determination for that period, the DNSP suffers a penalty, in that it has had to finance capital costs in the 2011-15 regulatory control period arising from the 'overspend' which were not included in the return on capital building blocks based on the AER's forecast of capex used to calculate the DNSP's annual revenue requirements for that period. Again, financing costs in 2011-15 operate as an incentive for capex efficiency.

The depreciation building blocks included in a DNSP's annual revenue requirements for the 2011-15 regulatory control period do not include any depreciation allowance on the capex 'overspend'. However, under a forecast depreciation approach, at the end of the regulatory control period the depreciation adjustment made in determining the opening RAB for the 2016-20 regulatory control period pursuant to clause S6.2.1(e)(3) does not include depreciation for the 2011-15 regulatory control period on the capex 'overspend'. Thus, under a forecast depreciation approach, the depreciation removed from the DNSP's opening RAB value for the 2016-20 regulatory control period is confined to the return of capital the DNSP receives during that period.

In summary, the capex efficiency incentives under a forecast depreciation approach are confined to those arising from finance costs. This is because, regardless of the capex that the DNSP actually incurs in 2011-15, the DNSP's RAB will be adjusted for depreciation for the period in the same amount for the purposes of determining the DNSP's opening RAB value for the 2016-20 regulatory control period.

It follows that, under a forecast depreciation approach, the risks and rewards of any divergence between actual and forecast capex lie almost entirely with users. If the DNSP achieves efficiencies in capex in 2011-15, its RAB at the commencement of the 2016-20 regulatory control period will be reduced by a greater amount than would have been the case, had actual depreciation been used, resulting in lower annual revenue requirements (and lower prices for users) in that latter period. Conversely, if the DNSP suffers inefficiencies in capex in 2011-15, its RAB at the commencement of the 2016-20 regulatory control period will be inflated by a greater amount than would have been the case, had actual depreciation been used, resulting in higher annual revenue requirements (and higher prices for users) for the latter period.

In essence, under a forecast depreciation approach, the benefits of any capex efficiency gains and the penalties of any capex inefficiencies are passed through to users. There is no sharing of the benefits (detriments) of capex efficiencies (inefficiencies) between DNSPs and users.

How choice of depreciation methodology under clause 6.12.1(18) creates efficiency incentives for capex – Depreciation based on actual capex

An actual depreciation approach creates additional efficiency incentives for capex relative to those existing where forecast depreciation is used. Under an actual depreciation approach, as under a forecast depreciation approach, finance costs are an incentive for capex efficiency. However, under an actual depreciation approach, the depreciation adjustment made under clause S6.2.1(e)(5) of the Rules operates to create additional incentives for capex efficiency that do not exist under a forecast depreciation approach.

Under both an actual and forecast depreciation approach, if the DNSP achieves efficiencies in its capex in the 2011-15 regulatory control period, such that its capex for 2011-15 falls below the forecast capex allowed by the AER in calculating the DNSP's annual revenue requirements for the period, the DNSP receives a benefit from not having to finance the avoided capex. However, under an actual depreciation approach, the DNSP receives an additional benefit in that the depreciation adjustment made in determining the opening RAB value for 2016-20 does not include depreciation for 2011-15 on the avoided capex. The opening RAB for 2016-20 is, thus, higher under an actual depreciation approach than it would have been under a forecast depreciation approach by the amount of depreciation for 2011-15 on the avoided capex, assuming capex incurred in 2011-15 would be the same under both an actual and forecast depreciation approach.

Similarly, under both an actual and forecast depreciation approach, if the DNSP is not able to achieve efficiencies in its capex during the 2011-15 regulatory control period, and instead expends more than the forecast capex allowed by the AER in calculating the DNSP's annual revenue requirements for the period, the DNSP receives a penalty from having to finance the capex 'overspend' in the period. However, under an actual depreciation approach, the DNSP receives an additional penalty in that the depreciation adjustment made in determining the opening RAB value for 2016-20 includes depreciation for 2011-15 on the capex 'overspend'. The opening RAB for 2016-20 is, thus, lower under an actual depreciation approach than it would have been under a forecast depreciation approach by the amount of depreciation for 2011-15 on the capex 'overspend', again assuming capex incurred in 2011-15 would be the same under both an actual and forecast depreciation approach.

An actual depreciation approach therefore creates an incentive for the DNSP, consistent with the RPP set out in section 7A(3) of the Law, to ensure that investment in its distribution system occurs efficiently, that is not present under the forecast depreciation approach. This is because the actual depreciation approach provides the DNSP with a benefit/penalty in respect of any efficiency gain/loss that is not conferred on the DNSP under the forecast depreciation approach. Put another way, the actual depreciation approach involves a sharing of the benefits (detriments) of capex efficiencies (inefficiencies) between DNSPs and users.

APPENDIX B - INDEX OF ATTACHMENTS AND ADDITIONAL DOCUMENTS REFERRED TO

Attachment	Description
Attachments	
1.	Ernst & Young, *South Australia domestic electricity prices 1998-2010: The contribution of network costs, A report for ETSA Utilities*, December 2011 (EY Report (SA))
2.	Ernst & Young, *Victorian domestic electricity prices 1996-2010: The contribution of network costs, A report for the Victorian electricity network businesses*, 9 September 2011 (EY Report (Vic))
Additional AER decisions referred to (links provided)	
3.	AER, *Final Decision, Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008 (AER's EBSS Final Decision): http://www.aer.gov.au/content/item.phtml?itemId=720374&nodeId=f4b47f94ccd27022f634a6b8422748e8&fn=Final%20decision%20-%20Distribution%20EBSS%20(26%20June%202008).pdf.
4.	AER, *Electricity distribution network service providers, Efficiency benefit sharing scheme*, June 2008 (AER's EBSS): http://www.aer.gov.au/content/item.phtml?itemId=720374&nodeId=43a5f51a883f454c16285f7a3da03f09&fn=Appendix%20E%20-%20Distribution%20EBSS%20(26%20June%202008).pdf.
5.	AER, *Final Decision-Public, Wagga Wagga Gas Distribution Network*, March 2010: http://www.aer.gov.au/content/item.phtml?itemId=735363&nodeId=272388293893a5be1da294dc1bd834fc&fn=Final%20decision.pdf
6.	AER *Final Decision-Public, Jemena Gas Networks, Access arrangement proposal for the NSW Gas Networks*, 11 June 2010: http://www.aer.gov.au/content/item.phtml?itemId=737314&nodeId=1ad7842f5a6f6ca1c7ca1818abf1bc95&fn=Final%20decision%20-%20public.pdf

7.	AER, *Final Decision-Public, ACT, Queanbeyan and Palerang gas distribution network*, 26 March 2010: http://www.aer.gov.au/content/item.phtml?itemId=735358&nodeId=2794c4e236689f94fe773247aacbe549&fn=Final%20decision.pdf.
8.	AER, *Final Decision, APT Allgas, Access arrangement proposal for the QLD gas network*, June 2011: http://www.aer.gov.au/content/item.phtml?itemId=747110&nodeId=3213928b091638400963e7d80dcbb9af&fn=Access%20arrangement%20final%20decision%20-%20APT%20Allgas.pdf.
9.	AER, *Final Decision, Envestra Ltd Access arrangement proposal for the QLD gas network*, June 2011: http://www.aer.gov.au/content/item.phtml?itemId=747106&nodeId=f8f4aa5eecb6b96b51b5fab14b393eed&fn=Access%20arrangement%20final%20decision%20-%20Envestra%20(Qld).pdf.
10.	AER, *Final Decision, Envestra Ltd Access arrangement proposal for the SA gas network*, June 2011: http://www.aer.gov.au/content/item.phtml?itemId=747093&nodeId=3f36a6f3aaab7dc7aeb06f936fc5eb03&fn=Access%20arrangement%20final%20decision%20-%20Envestra%20(SA).pdf.
11.	AER, *Final Decision-Public, N.T Gas, Access Arrangement for the Amadeus Gas Pipeline*, July 2011: http://www.aer.gov.au/content/item.phtml?itemId=748050&nodeId=f679e85ff5c7e835b0764861a444772c&fn=NT%20Gas%20Final%20decision%20-%20Public.pdf.
Additional cases referred (links provided)	
12.	*Telstra Corporation Ltd (No 3)* [2007] ACompT 3: http://www.austlii.edu.au/au/cases/cth/ACompT/2007/3.html.
13.	*Telstra Corporation Limited v Australian Competition Tribunal* [2009] FCAFC 23: http://www.austlii.edu.au/cgi-bin/sinodisp/au/cases/cth/FCAFC/2009/23.html?stem=0&synonyms=0&query=title(telstra%20corporation%20limited%20v%20australian%20competition%20tribunal%20).
14.	*Application by United Energy Distribution Pty Limited* [2012] ACompT 1: http://www.austlii.edu.au/au/cases/cth/ACompT/2012/1.html.

South Australia domestic electricity prices 1998-2010: The contribution of network costs

A report for ETSA Utilities

7 December 2011

ERNST & YOUNG

Contents

1. Executive summary

Ernst & Young was engaged by ETSA Utilities to:

- Conduct an independent analysis of the trend in South Australian electricity prices over the medium term;
- Disaggregate the trend to examine the role of network costs in the changes in South Australian electricity prices; and
- To the extent possible, compare the results with those observed in New South Wales and Queensland.

This report provides the outcome of our work.

1.1 Approach

Analysing electricity prices over long periods of time presents a number of challenges due to changes in industry structure, ownership, information gathering processes and publication, the technology employed, the number and structure of tariffs over time, consumer behaviour and the tax system (e.g. the introduction of the Goods and Services Tax (GST)).

The Australian Bureau of Statistics (ABS) produces an electricity price index (*ABS Consumer price index, catalogue no.6401.0 Table 13*) for each capital city[1] that commences in 1980 and shows the trend in electricity prices since that time. We used that index in our analysis. The ABS does not however disaggregate the index into the components that constitute the final retail electricity price.

To analyse the trend in South Australian electricity prices over the medium term, we relied mostly on a bottom up approach as it uses the actual retail and network tariffs paid by customers. In particular, we examined the historical trend of annual electricity costs for the typical domestic customer[2] under the single rate tariff from 1998-99 to 2010-11 (excluding GST) and disaggregated the trend down to the network and non-network components of retail electricity prices:

- Network costs (NUOS) have been disaggregated into distribution use of system costs (DUOS) and transmission use of system costs (TUOS).
- Non-network costs refer to all costs involved in the supply of electricity other than distribution and transmission use of system charges and includes costs such as wholesale energy costs and retail margins.

The single rate tariff is representative of typical domestic electricity prices because this is the only network tariff offered to domestic customers in South Australia.

We did not analyse the cost of electricity in the business or non-domestic sectors because a similar analysis using the actual tariffs paid by these customers is not feasible for several

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[1] While the ABS produces its electricity price index (which forms part of its Consumer Price Index) for each State and Territory capital city, the index is widely assumed to be representative for the whole State or Territory. In this instance, the ABS electricity price index for Adelaide is assumed to be broadly representative of domestic electricity prices in South Australia.

[2] The typical domestic customer is defined as a customer under a domestic single rate tariff with an average consumption profile throughout the period of analysis (i.e. consuming average consumption volumes in each year from 1998-99 to 2010-11. State-wide average consumption data sourced from the ESAA's annual Electricity Gas Australia publications). See Section 3 and Appendix A for more details.

reasons, including data limitations, the large number and complex structure of non-domestic tariffs and the prevalence of individually negotiated "non-standard" contracts.

Between 1998-99 and 2010-11, on average, domestic customers accounted for approximately 35 per cent of total energy demand in South Australia and around 88 per cent of customers by numbers.

All the data used in our analysis is publicly accessible. To validate our analysis, ETSA Utilities provided confidential data on customer numbers and average consumption by tariff. However, this data has not been used in our analysis or presented in our findings. All of the findings are able to be replicated using publicly accessible information.

We further verified our results by, amongst other things, comparing the findings derived from the analysis described above:

- With the results of our disaggregation of the ABS electricity price index for Adelaide as opposed to actual tariffs paid by customers (the top down approach); and
- With the annual price changes allowed by economic regulators in each year of the regulatory periods in distribution determinations made for ETSA Utilities (i.e. derived from P-noughts and X factors).[3]

We also adopted the approach described above to disaggregate the change in annual electricity costs in NSW and Queensland.

1.2 Our results

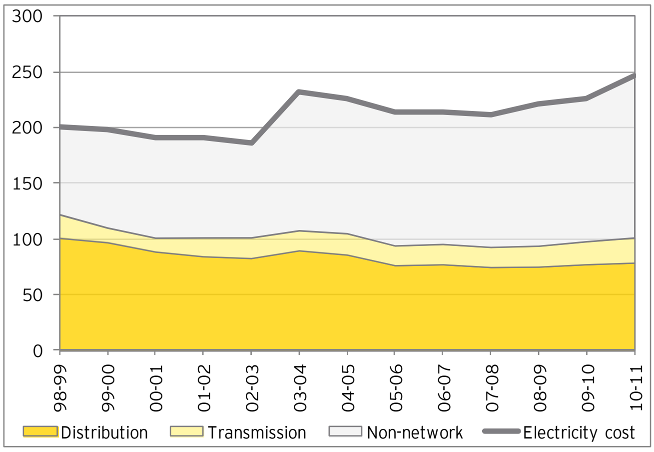
Our analysis shows that:

- Electricity prices and typical bills for the typical domestic customer in South Australia increased by 23 per cent in real terms from 1998-99 to 2010-11. However since 2003-04, domestic electricity prices only increased by 6 per cent in real terms. This followed a more significant increase in domestic electricity prices of 16 per cent in real terms between 1998-99 and 2003-04; and
- The increases in domestic electricity prices in South Australia cannot be explained by increases in network costs (i.e. the sum of distribution and transmission use of system charges).

Figure 1 illustrates what has happened to the relevant components of average South Australian electricity prices in real terms over the period 1998-99 to 2010-11. It separates retail prices into network costs and non-network costs (i.e. wholesale energy costs and retailers' costs).

[3] Determinations made under the South Australian Electricity Pricing Order 1999, and distribution determinations made by ESCOSA and the AER. See Appendix B for details.

Figure 1 South Australia electricity costs by component 1998-99 to 2010-11 ($ per MWh, real 2010)



Source: Ernst & Young analysis

Figure 1 shows that network costs per megawatt-hour (MWh) in South Australia decreased by 17 per cent in real terms between 1998-99 and 2010-11. On a per customer basis, network costs decreased by 12 per cent in real terms. The difference reflects the increase in average consumption during this period.

Table 1 below shows the results numerically.

Table 1 Change in average annual South Australian electricity costs from 1998-99 to 2010-11 (real 2010)

	Percentage change		Dollar change	
	per MWh	per customer	per MWh	per customer
Final retail price	+23%	+31%	+$46	+$363
Network	-17%	-12%	-$21	-$88
Distribution	-22%	-18%	-$22	-$105
Transmission	+7%	+13%	+$1	+$17
Non-network	+86%	+98%	+$67	+$451

Figures may be affected by rounding. Source: Ernst & Young analysis

Disaggregating network costs between the distribution and transmission elements reveals annual distribution network costs between 1998-99 and 2010-11 decreased to a greater extent than total network costs. Between 1998-99 and 2010-11:

- Distribution use of system costs decreased by 22 per cent in real terms; and
- Transmission use of system costs increased by 7 per cent in real terms, but have been quite volatile, albeit within a narrow range, due to factors unrelated to the actual cost of providing transmission services such as the influence of settlements residue auction proceeds. These reasons are described in Section 4.1.1.[4]

In contrast, non-network costs increased by 86 per cent in real terms between 1998-99 and 2010-11.

In other words, for the typical domestic customer, annual network costs in South Australia decreased in real terms between 1998-99 and 2010-11:

- On a per MWh distributed basis;
- On a per customer basis;

[4] Figures may be affected by rounding.

- In excess of the benefits that may reasonably be expected from load growth (refer to Section 4.1.4).

Based on our analysis, the increases in electricity prices in South Australia over the 1998-99 to 2010-11 period cannot be attributed to network costs.

Further, we are aware of the significant increases in electricity prices for domestic customers in South Australia in 2011-12. As a result, we have extended our analysis of electricity prices to include the current year 2011-12, as shown in Appendix B.

1.2.1 Consistency of results

We validated our bottom up findings with the results from an analysis of the trend in South Australian domestic electricity prices achieved by disaggregating the ABS electricity price index for Adelaide[5] (i.e. the top down approach). The top down approach produces similar outcomes in terms of the performance of network costs, but we have greater confidence in the results using our bottom up approach because they rely on actual tariffs rather than a price index.

We also compared our findings with the results produced by undertaking a similar analysis using the domestic 'hot water tariff' (i.e. single rate with separate controlled load tariff). This comparison produced similar outcomes in terms of the trend in network costs.

Our findings on annual network charges are also consistent with the annual price changes allowed by economic regulators in each year of the regulatory periods in distribution determinations made for ETSA Utilities.

The South Australian results in respect of network costs differ from the results of our analysis for New South Wales (NSW) and Queensland (refer to Section 5). In these States, network costs increased in part due to the substantial capital investments that have been made, particularly in recent years. The different results between States may also reflect the different starting points in respect of each network's existing capital stock.

[5] Assumed to be representative of the general trend in electricity prices in South Australia. Refer to footnote 1.

Glossary

Reference	Description
ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CPI	Consumer Price Index
CSO	Community Service Obligation
DUOS	Distribution Use of System
EPO	Electricity Pricing Order, issued by the South Australian Treasurer on 11 October 1999
ESCOSA	Essential Services Commission of South Australia
ESAA	Energy Supply Association of Australia
FRC	Full Retail Contestability
GST	Goods and Services Tax
IPART	Independent Pricing and Regulatory Tribunal
MWh	Megawatt-hour
NEM	National Electricity Market
NSW	New South Wales
NUOS	Network Use of System
QCA	Queensland Competition Authority
QLD	Queensland
TUOS	Transmission Use of System

2. Introduction

2.1 Scope of work

Ernst & Young Australia (Ernst & Young) was engaged by ETSA Utilities to assess the trend in South Australian electricity prices and network costs. More specifically, Ernst & Young was engaged to:

- Conduct an independent analysis of the trends in South Australian electricity prices over the medium term;
- Disaggregate those trends to examine the role of network costs in the changes in South Australian electricity prices; and
- Compare the results with those observed in New South Wales and Queensland.

Section 3 describes the approach undertaken to complete the work.

2.2 Outline of report

This report provides the output of our analysis. In particular:

- Section 3 describes our approach;
- Section 4 provides an overview of our key findings; and
- Section 5 provides an overview of our key findings in NSW and Queensland.

There are two appendices:

- Appendix A – Approach, which provides additional details on our methodology, data sources and key assumptions; and
- Appendix B – Other results, which provide an overview of other relevant findings, including an analysis of electricity prices in 2011-12.

3. Approach

We analysed the historical trend of domestic retail electricity prices in South Australia for each year from 1998-99 to 2010-11 and disaggregated the change in prices down to the network and non-network components (i.e. wholesale energy costs and retailers' costs) of retail electricity prices.

Network use of system (NUOS) costs have been disaggregated further into distribution use of system (DUOS) costs and transmission use of system (TUOS) costs.

This allowed us to determine the change in the proportion of the typical customer's annual electricity costs paid to the network businesses through network charges, and the change in the proportion that is paid to other non-network entities (e.g. retailers, generators etc.).

3.1 Methodology

Analysing electricity prices over long periods of time presents a number of challenges due to changes in industry structure, ownership, information gathering processes and publication, the technology employed, the number and structure of tariffs over time, consumer behaviour and the tax system (e.g. the introduction of the GST).

For example, there have been numerous structural, regulatory and policy decisions that significantly impacted the South Australian electricity industry since 1998-99, including

- The commencement of the National Electricity Market in December 1998, in which South Australia was a participant;
- The staged disaggregation of the then State-owned electricity industry business, ETSA Corporation, between 1998 and 2000 ;
- Privatisation of the electricity distribution network and transmission network businesses in 1999-2000;
- The introduction of the GST in July 2000;[6] and
- The implementation of Full Retail Contestability (FRC) between December 1998 (for large industrial customers) and January 2003 (for domestic customers).

Furthermore, significant volumes of historical tariff data are often unavailable, particularly where businesses were restructured or where data storage platforms changed considerably.

The single rate tariff is representative of typical domestic electricity prices because this is the only network tariff offered to domestic customers in South Australia.

To analyse the trend in South Australian electricity prices over the medium term, we relied principally on a bottom up approach as it uses the actual retail and network tariffs paid by customers. Using these tariffs, we examined the historical trend of annual electricity costs for the typical domestic customer from 1998-99 to 2010-11 and disaggregated the change in the trend down to the network (i.e. disaggregating between distribution and transmission) and non-network components of retail electricity prices.

To undertake this assignment, we took the following broad approach:

[6] All prices and costs exclude GST to the extent that all tariff data we have used in our analysis is exclusive of GST. We have not excluded the impact of the introduction of the GST in July 2000 on CPI / inflation data. However we expect that the impact on our final results is unlikely to be material.

- We obtained data on annual retail electricity tariffs in South Australia for domestic customers from the South Australian Government Gazette for each year from 1998-99 to 2010-11. Using these tariffs, we estimated the cost of electricity paid each year by a South Australian customer with an average consumption profile[7] under a domestic single rate tariff in this period;
- We then determined the proportion of the annual electricity costs attributable to the network component, by undertaking the above analysis for the domestic single rate distribution network and transmission network tariffs; and
- We assumed that distribution and transmission costs included the cost of the various pass through events and adjustments in South Australia during this period.[8]

Given the significant increases in default and standing contract retail and network tariffs for the 2011-12 financial year, we have extended our analysis of South Australian electricity prices to include the current year 2011-12. We based our analysis on the default and standing contract retail and network tariffs for 2011-12 and an assumed 4 per cent decline in domestic consumption, driven by expected declining customer usage in response to price increases and the increased use of photovoltaic cells. Refer to Section B.1 for detail.

In NSW and Queensland, we were constrained by the unavailability of network tariff data prior to around 2001-02 due to additional data limitations of the type described above.

3.2 Qualifications

We undertook our analysis from 1998-99 to 2010-11 to reflect the performance of the South Australian electricity network businesses since they were privatised in 1999. The South Australian Treasurer also issued an Electricity Pricing Order (EPO) in October 1999 to regulate network prices in South Australia. Prior to this, there are significant limitations on the availability of data required to disaggregate electricity prices.

Our findings are first determined in terms of annual cost per customer. We then express the annual cost on a per unit of volume basis (i.e. MWh) by dividing the annual cost per customer by average consumption for that year.[9]

Unless otherwise stated, all findings express our estimates of the annual electricity costs paid by the typical domestic customer, i.e. a customer with an average consumption profile in each year from 1998-99 to 2010-11.

We did not analyse the cost of electricity in the non-domestic or business sectors for various reasons, including the limited availability of consistent data, large numbers of non-domestic tariffs, complexity of the non-domestic tariff structures and prevalence of non-standard contracts negotiated individually with the retail business.

All the data we used in our analysis is publicly accessible. To validate our analysis, the South Australian electricity network businesses provided confidential data on customer numbers and average consumption by tariff type. However this data has not been used in our analysis or presented in our findings. All of the findings are able to be replicated using publicly accessible information.

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[7] State-wide average consumption data for each year from 1998-99 to 2010-11 was sourced from the ESAA's annual Electricity Gas Australia publications.
[8] Distribution costs are assumed to include the costs of the Outage Management System and the Full Retail Contestability pass throughs from 2002-03 and 2003-04, and the costs of three pass through events in 2009-10. Transmission costs are assumed to include the cost of the TUOS pass through in 2002-03, 2003-04 and 2004-05 and the rebate of ElectraNet's TUOS charges between 1999-00 to 2001-02. Refer to Section A.3 for further detail.
[9] For example, if the annual cost per customer is $1,000 and consumption for the year is 5,000kWh or 5 MWh, the cost per MWh distributed is $200 per MWh.

3.3 Verification of results

We have only presented the findings from our bottom up analysis of the domestic single rate tariff.

However we also analysed and disaggregated the trend in electricity prices using other approaches to test the sensitivity and robustness of our findings under the single rate tariff. We compared the findings derived from the analysis described above with:

- The results of our top down approach, which disaggregates the ABS electricity price index for Adelaide;
- The annual price changes allowed by economic regulators in each year of the regulatory periods in distribution determinations made for ETSA Utilities (i.e. derived from P-noughts and X factors); and
- The results derived from similar bottom up analysis described above using the domestic 'hot water tariff'.[10]

Both the bottom up analysis of the hot water tariff and the top down approach produce results which are consistent with the single rate tariff.

Appendix A describes our approach in more detail. Appendix B provides some additional results of our analysis.

[10] This refers to customers under the domestic single rate tariff with separate controlled load tariff.

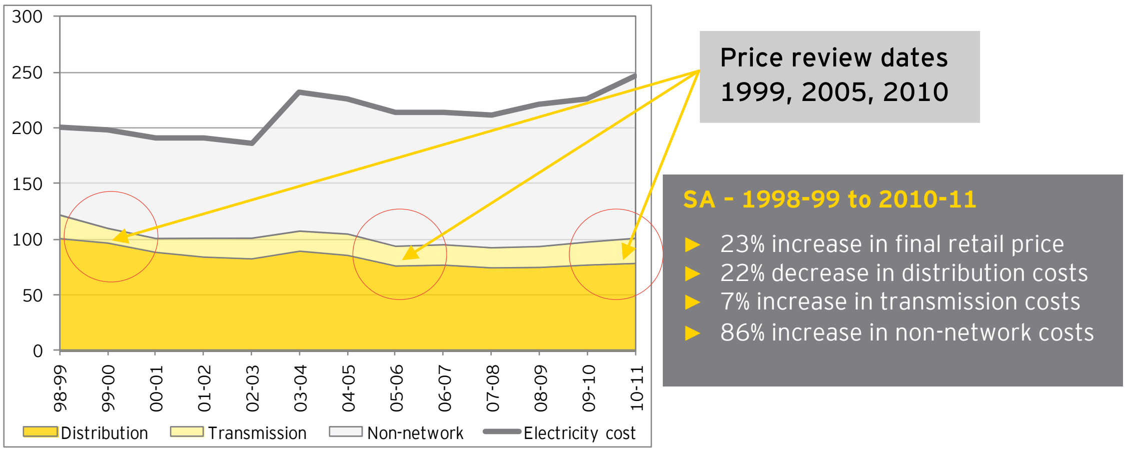
4. Key findings

4.1 South Australia

4.1.1 Costs per MWh

Our findings from the disaggregation of costs under the domestic single rate tariff in Figure 2 show the cost of electricity in real dollars per MWh paid by the typical customer increased by 23 per cent from 1998-99 to 2010-11. It also shows relevant distribution price review dates for ETSA Utilities and summarises the impact on the key components of electricity prices.

Figure 2 South Australia electricity costs by component 1998-99 to 2010-11 ($ per MWh, real 2010)



Source: Ernst & Young analysis

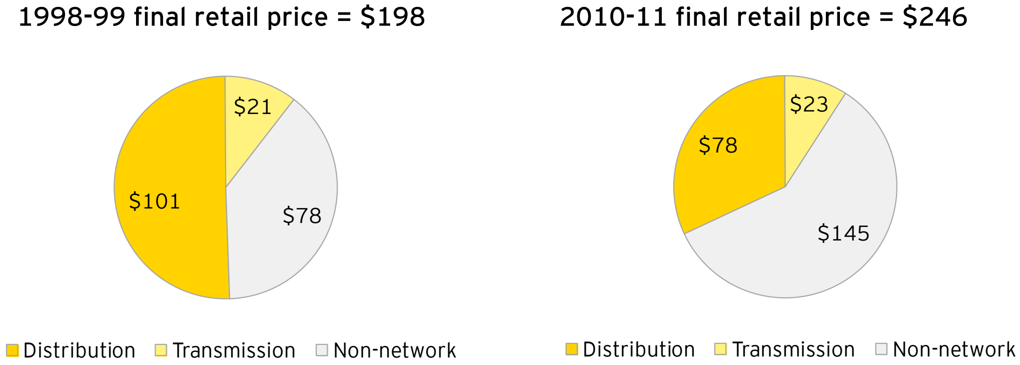
In other words, between 1998-99 and 2010-11:

- Network costs decreased by 17 per cent in real terms. Disaggregating network costs further shows that:
  - Distribution costs decreased by 22 per cent in real terms; and
  - Transmission costs increased by 7 per cent in real terms, but have been quite variable, albeit within a narrow range. In practice, there are several reasons for this that are unrelated to the cost of providing transmission services, the main driver being the proceeds from settlement residue auctions, which can be volatile from year to year, both in terms of their quantity and incidence (i.e. which jurisdiction bears the costs).[11]
- Non-network costs (i.e. wholesale energy and retailers' costs) increased by 86 per cent in real terms.

Figure 3 shows the breakdown of South Australian electricity costs between distribution network, transmission network and non-network costs in 1998-99 and 2010-11.

[11] 'Transmission' costs as measured capture some costs that are in practice unrelated to transmission services. These include most notably settlements residue related receipts. In 2010-11, these receipts were equivalent to about 5 per cent of ElectraNet's transmission revenue. See AEMO, SRA Memorandum 2011. .

Figure 3 Composition of electricity costs in South Australia 1998-99 and 2010-11 ($ per MWh, real 2010)

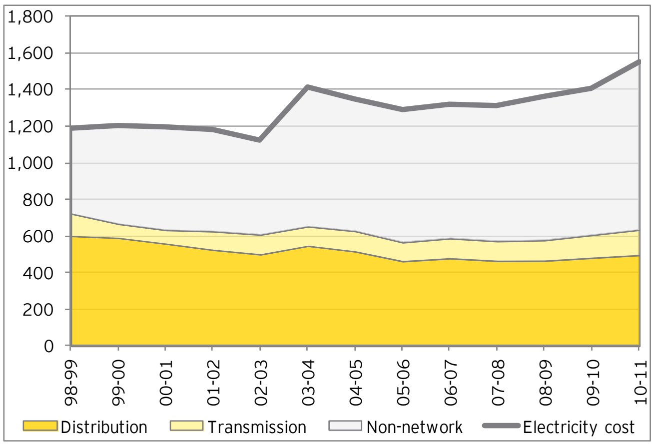


Note: Figures may be affected by rounding. Source: Ernst & Young analysis

4.1.2 Costs per customer

Analysing the breakdown of South Australian electricity costs on a per customer basis, as shown in Figure 4, produces broadly consistent results with our findings on a per MWh basis.

Figure 4 South Australian electricity costs by component 1998-99 to 2010-11 ($ per customer, real 2010)



SA - 1998-99 to 2010-11

- 31% increase in final retail price
- 18% decrease in distribution costs
- 13% increase in transmission costs
- 98% increase in non-network costs

Source: Ernst & Young analysis

Figure 4 shows that between 1998-99 and 2010-11:

- The cost of electricity in real dollars per customer paid by the typical customer increased by 31 per cent.
- Network costs decreased by 12 per cent in real terms;
  - Distribution costs decreased by 18 per cent in real terms; and
  - Transmission costs increased in real terms by 13 per cent;[12]
- Non-network costs increased by 98 per cent in real terms.

The difference in the magnitude in the change in costs per customer compared with costs per MWh from 1998-99 to 2010-11 is explained by the increased average consumption rates during this period.

[12] Refer to footnote 11 for detailed discussion of the volatility of transmission costs in South Australia.

4.1.3 Analysis of a typical annual bill in nominal terms

Our analysis of the typical annual bill shows that the annual cost of electricity in nominal terms, paid each year by the typical customer increased by 89 per cent from $821 to $1,549 between 1998-99 and 2010-11.

$821	$1,549	$728
The cost of the typical annual domestic electricity bill in South Australia in 1998-99	The cost of the typical annual domestic electricity bill in South Australia in 2010-11	Increase in the typical annual domestic electricity bill in SA from 1998-99 to 2010-11

Table 2 shows a breakdown of the typical South Australian domestic electricity bill in 1998-99 and 2010-11, in nominal dollars.

Table 2 Breakdown of a typical electricity bill in South Australia ($ per customer, nominal)

	1998-99	2010-11
Annual cost of bill ($, nominal)		
Network - distribution	$414	$493
Network - transmission	$87	$143
Non-network	$320	$913
Final retail price	$821	$1,549
Proportion of final retail price (%)		
Network - distribution	50%	32%
Network - transmission	11%	9%
Non-network	39%	59%

Note: Figures may be affected by rounding. Source: Ernst & Young analysis

Breaking down the nominal bill increase between 1998-99 and 2010-11 of $728, it is evident that:

- Network costs contributed 19 per cent ($134) of the increase in the average electricity bill,[13] which in turn is disaggregated between distribution and transmission, where;
  - Distribution costs contributed 11 per cent ($79) of the increase;
  - Transmission costs contributed 8 per cent ($56) of the increase;
- Non-network costs contributed 81 per cent ($593) of the increase in the average electricity bill.[14]

4.1.4 Zero load growth for a typical customer

This scenario has been analysed to attempt to determine the impact of consumption growth, or load growth, on the cost of the network component each year for a typical domestic customer in South Australia.

We focused our analysis on the network charges paid by a typical domestic customer as opposed to overall network costs because focussing on the latter is not possible without access to a network business's tariff model due to the complex nature of determining network charges.

[13] Note that the increase in network costs is due to the figures being expressed in nominal terms.
[14] Figures may be affected by rounding.

Network businesses typically set tariffs based on two factors, the total amount of costs to recover through its network charges and the volume of electricity it distributes. However there are issues with the behaviour of these two factors which makes undertaking this analysis complex.

- Costs – if average consumption was fixed from 1998-99 to 2010-11, a network business would not necessarily have invested the same amount to expand or upgrade its network.[15] This would mean that it is likely that the network business would set a lower network charge than otherwise because the total amount of costs to recover would be lower.

- Volume – given price is broadly a function of costs and volume, if a network business distributes less electricity than expected (for example, if growth in average consumption is zero), it would most likely set a higher network charge to ensure it recovers its costs.

Typically for networks, it would be reasonable to expect increasing volumes to increase total costs but result in declining per unit costs, depending upon the relative growth rates of peak demand.

Whether network charges would be higher or lower under a zero load growth scenario would depend on which of these two opposing impacts (lower costs to recover versus lower volumes from which to recover costs) is stronger. The results should therefore be interpreted with some caution.

Table 3 compares the distribution costs paid by a typical customer in South Australian in 1998-99 and 2010-11 with the distribution costs the same customer would pay if his or her consumption remained at 1998-99 levels.

Table 3 Annual distribution costs of a typical customer in South Australia ($ per customer, real 2010)

	1998-99	2010-11	Change ($)
Typical customer	$598	$493	-$105
Zero load growth	$598	$466	-$132

Source: Ernst & Young analysis

In terms of annual distribution network costs, the typical customer in South Australia was better off by $105 between 1998-99 and 2010-11.

A typical customer whose consumption remained at 1998-99 levels was a further $27 better off. This customer was better off by $132 between 1998-99 and 2010-11.

The implication of this analysis is that performance improvements in the South Australian distribution network have likely played some role. Table 3 suggests South Australian domestic electricity customers received benefits in addition to those benefits that one might reasonably expect to arise from increasing volumes (i.e. benefits from increasing total costs but declining per unit costs).

In other words, total network costs for South Australian domestic electricity customers decreased despite increasing volumes.

4.1.5 Comparison with regulatory determinations

We also cross-checked our findings by comparing the trend in distribution network costs in South Australia between 1999-00 and 2010-11 with the annual price changes for the distributor's network businesses allowed in regulatory determinations during this period (i.e. derived from P-noughts and X factors).

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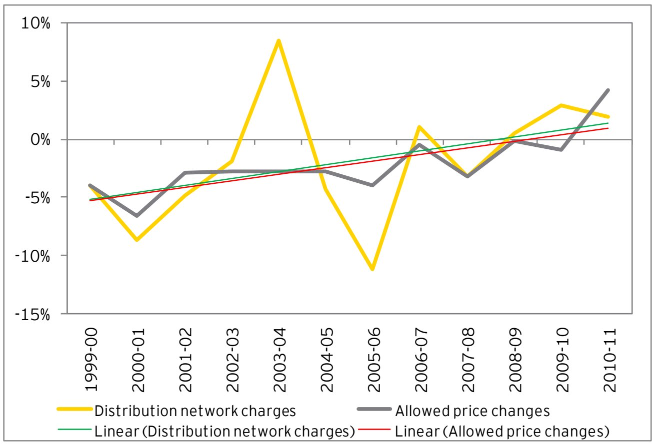
[15] The key relationship for cost is with the disaggregated growth in peak demand,

It is apparent from Figure 5 that while actual domestic distribution charges were more volatile, there is a high degree of consistency between distribution charges and price changes allowed by economic regulators over the 1998-99 to 2010-11 period.

The 'spike' in distribution charges in 2003-04 was driven by the introduction of FRC to domestic customers in January 2003. Under FRC, ETSA Utilities incurred significant additional capital and operating expenditure due to new responsibilities related to the provision of metering services to particular customers. As a result, distribution charges in 2003-04 and 2004-05 included a pass-through of ETSA Utilities' additional FRC costs, which added 8 per cent to annual distribution charges.

Figure 5 South Australian annual changes in electricity distribution network prices 1999-00 to 2010-11 (%)



Source: Ernst & Young analysis, AER, ESCOSA

4.1.6 South Australian summary

Our analysis shows that for South Australian domestic electricity customers:

- Network costs were not the driver of the increase in retail electricity prices for domestic customers between 1998-99 and 2010-11;
  - Distribution network costs decreased by 22 per cent in real terms between 1998-99 and 2010-11;
  - Transmission network costs increased by 7 per cent in real terms during this period, but are volatile on a year to year basis for several reasons that are in practice unrelated to the cost of providing transmission services;
- In contrast, non-network costs (i.e. wholesale energy costs and retailers' costs) increased by 86 per cent between 1998-99 and 2010-11.

These results are supported by the findings of all of the additional analysis we undertook, that is:

- Analysing the typical annual bill for the typical customer;
- Disaggregating electricity prices using the top down approach;
- Performing the equivalent analysis to disaggregate the domestic 'hot water tariff'; and
- Comparing the findings on annual network charges against the price changes allowed in regulatory determinations made for the distributors' network businesses.

5. Other jurisdictions – New South Wales and Queensland

We applied a similar approach to analyse the historical trend in domestic retail electricity costs and the disaggregation between the network and non-network components in NSW and Queensland.

There were three key differences in our analysis of NSW and Queensland electricity prices:

- Prior to around 2001-02, we were constrained by the unavailability of network tariff data. To overcome this, we interpolated the network tariff data back to 1998-99 using the P-noughts and X factors allowed in each year of the regulatory periods in determinations made by the economic regulator;
- Unlike in South Australia, the annual prices submitted to the regulator by NSW and Queensland distribution businesses do not disaggregate network prices into distribution (i.e. DUOS) and transmission (i.e. TUOS) prices. We were therefore unable to disaggregate network tariffs; and
- We adjusted for an issue in Queensland retail electricity prices caused by the Uniform Tariff Policy. Refer to Section A.1.1 for more detail.

Our analysis shows that the increases in annual domestic electricity prices in NSW and Queensland paid by the typical customer between 1998-99 and 2010-11 are explained by increases in network costs.

Between 1998-99 and 2010-11, network costs paid by the typical customer in NSW and Queensland increased in real terms by 82 per cent and 110 per cent respectively. Table 4 shows the results.

Table 4 Change in average annual electricity costs from 1998-99 to 2010-11 ($ per MWh, real 2010)

	Percentage change		Dollar change	
	New South Wales	Queensland	New South Wales	Queensland
Final retail price	+52%	+50%	+$73	+$68
Network	+82%	+110%	+$51	+$57
Non-network	+28%	+14%	+$23	+$12

Note: Figures may be affected by rounding. Source: Ernst & Young analysis

Several interested parties cited the key drivers of increasing network costs (and hence electricity prices) in NSW and Queensland to include rising peak demand and the need to replace ageing and obsolete assets. These parties include Ausgrid,[16] the Australian Energy Regulator (AER),[17] the Australian Industry Group[18] and the Reserve Bank of Australia.[19]

We present the following findings from our analysis of electricity prices in NSW and Queensland:

- Disaggregation of costs under the domestic single rate tariff on a per MWh basis;

[16] George Maltabarow, Managing Director of Ausgrid, Appearance on Insight episode 'Power Play', 2 August 2011, transcript available at http://www.sbs.com.au/insight/episode/index/id/419/Power-Play#transcript
[17] AER, State of the energy market 2010, page 4
[18] Australian Industry Group, Energy shock: confronting higher prices, February 2011, page 21
[19] Reserve Bank of Australia, Developments in Utilities – Bulletin December Quarter 2010, available at http://www.rba.gov.au/publications/bulletin/2010/dec/2.html

▶ Typical annual bill;

▶ Comparing the change in network costs with price changes allowed in regulatory determinations; and

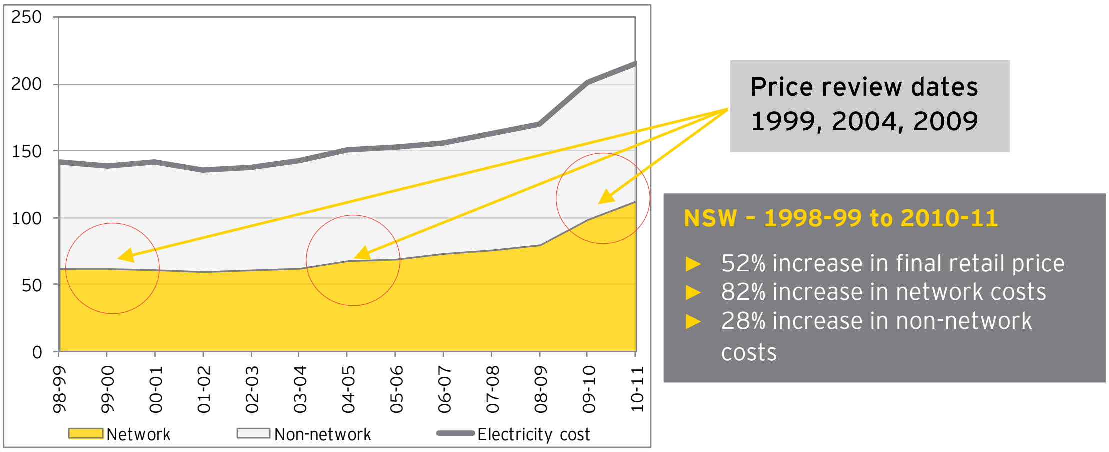
▶ Zero load growth for a typical customer (refer to Section B.3).

Our analysis shows that the change in annual network costs between 1998-99 and 2010-11 in NSW and Queensland are more significant than in South Australia.

5.1.1 Costs per MWh

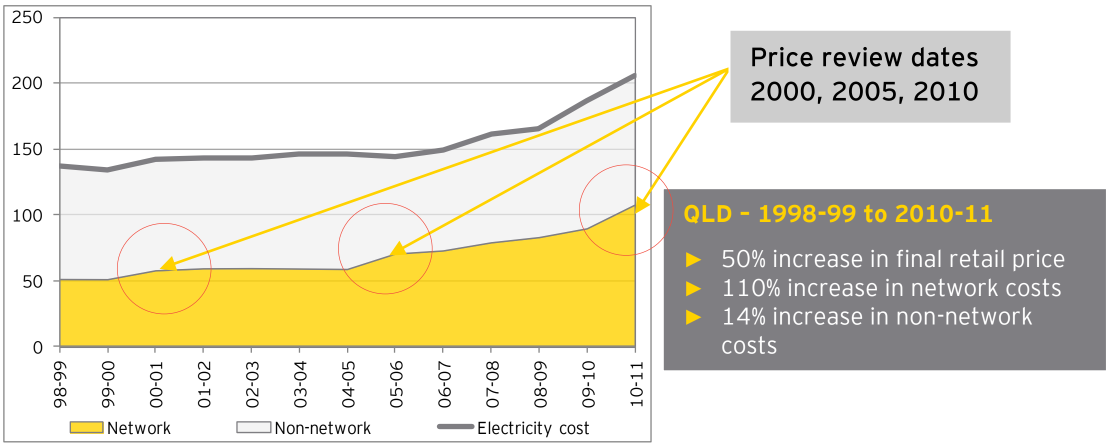
Figure 6 and Figure 7 show the disaggregation of costs under the domestic single rate tariff for NSW and Queensland. Costs are in real dollars per megawatt-hour (MWh) paid by the typical customer from 1998-99 to 2010-11. It also shows relevant price review dates and summarises the impact on the key components of electricity prices.

Figure 6 New South Wales electricity costs by component 1998-99 to 2010-11 ($ per MWh, real 2010)



Source: Ernst & Young analysis

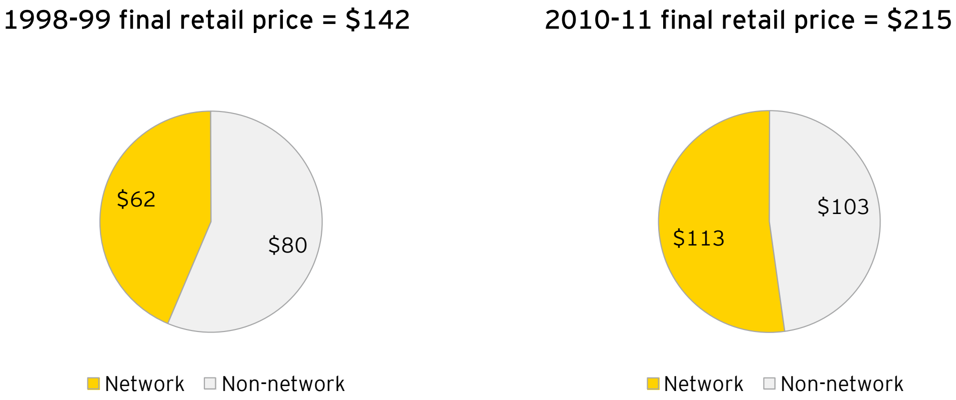
Figure 7 Queensland electricity costs by component 1998-99 to 2010-11 ($ per MWh, real 2010)



Source: Ernst & Young analysis

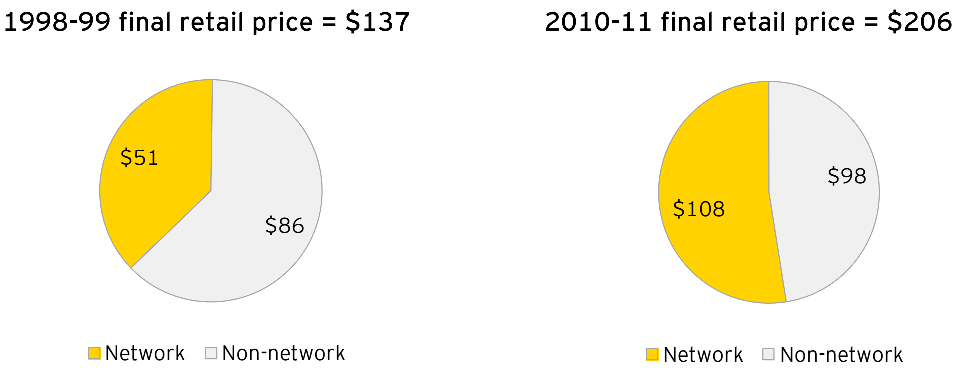
Figure 8 and Figure 9 show the breakdown of electricity costs between network and non-network costs in 1998-99 and 2010-11 for NSW and Queensland.

Figure 8 Composition of electricity costs in NSW 1998-99 and 2010-11 ($ per MWh, real 2010)



Note: Figures may be affected by rounding. Source: Ernst & Young analysis

Figure 9 Composition of electricity costs in Queensland 1998-99 and 2010-11 ($ per MWh, real 2010)



Note: Figures may be affected by rounding. Source: Ernst & Young analysis

5.1.2 Analysis of a typical average bill in nominal terms

For NSW, our analysis of the typical annual bill shows that the annual cost of electricity in nominal terms, paid each year by the typical customer increased by 107 per cent from $726 to $1,503 between 1998-99 and 2010-11.

$726	$1,503	$777
The cost of the average annual domestic electricity bill in NSW in 1998-99	The cost of the average annual domestic electricity bill in NSW in 2010-11	Increase in the average annual electricity bill in NSW from 1998-99 to 2010-11

Table 5 Breakdown of a typical electricity bill in NSW ($ per customer, nominal)

	1998-99	2010-11
Annual cost of bill ($, nominal)		
Network	$319	$785
Non-network	$407	$718
Final retail price	$726	$1,503
Proportion of final retail price (%)		
Network	44%	52%
Non-network	56%	48%

Note: Figures may be affected by rounding. Source: Ernst & Young analysis

For Queensland, our analysis of the typical annual bill shows that the annual cost of electricity in nominal terms, paid each year by the typical customer increased by 139 per cent from $673 to $1,608 between 1998-99 and 2010-11.

$673	$1,608	$935
The cost of the average annual domestic electricity bill in QLD in 1998-99	The cost of the average annual domestic electricity bill in QLD in 2010-11	Increase in the average annual electricity bill in QLD from 1998-99 to 2010-11

Table 6 Breakdown of a typical electricity bill in Queensland ($ per customer, nominal)

	1998-99	2010-11
Annual cost of bill ($, nominal)		
Network	$252	$844
Non-network	$421	$764
Final retail price	$673	$1,608
Proportion of final retail price (%)		
Network	37%	52%
Non-network	63%	48%

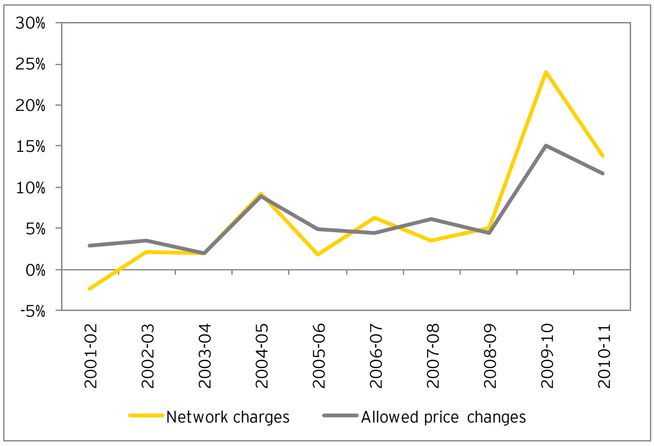
Note: Figures may be affected by rounding. Source: Ernst & Young analysis

5.1.3 Comparison with regulatory determinations

In NSW and Queensland, we performed the same cross-checks as in South Australia by comparing the trend in network costs with the annual price changes allowed by economic regulators in each year of the regulatory periods in determinations made for the distributors' network businesses (i.e. derived from P-noughts and X factors).[20]

These cross-checks for NSW and Queensland produced consistent results as the cross-checks for South Australia, suggesting reasonable consistency in the trend between network costs paid by a typical domestic customer and the price changes allowed by economic regulators between 2001-02 and 2010-11.[21]

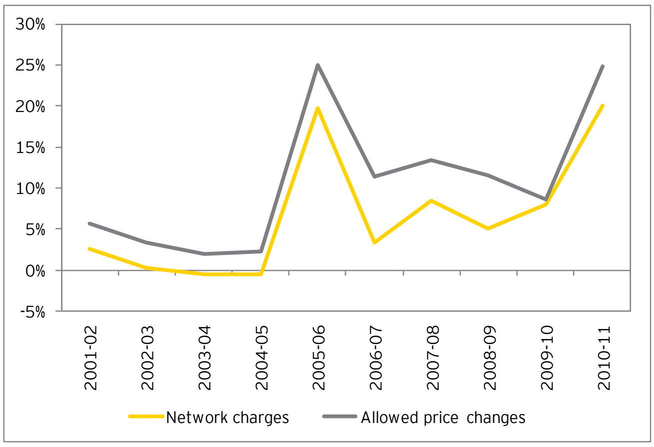
Figure 10 New South Wales annual changes in electricity network prices 2001-02 to 2010-11 (%)



Source: Ernst & Young analysis, AER, IPART

[20] Note that P-noughts and X factors for NSW and Queensland businesses are for distribution use of system prices only and do not include transmission use of system prices. These were sourced from distribution determinations made by the IPART, QCA and AER. See Appendix B for details.
[21] In NSW and Queensland, we have compared network charges and P-noughts / X factors from 2001-02 as were constrained by the unavailability of network tariff data in these States prior to this date.

Figure 11 Queensland annual changes in electricity network prices 2001-02 to 2010-11 (%)



Source: Ernst & Young analysis, AER, QCA

We also undertook an analysis of zero load growth scenarios in NSW and Queensland. These findings are presented in Appendix B.

Appendices to report

Appendix A: Approach

A.1. Methodology

The objective of our analysis is to:

- ► Determine the changes in domestic retail electricity prices in South Australia between 1998-99 and 2010-11; and
- ► Determine the changes in the components that make up the domestic retail electricity prices, having regard for the distribution network component, the transmission network component and the non-network component. The non-network component includes costs such as retailers' costs and wholesale energy charges and has been calculated as follows:

Non-network = Final retail price – Distribution – Transmission

We undertook two approaches to test the consistency and validity of our analysis: a bottom up and a top down approach. The bottom up approach involves disaggregating annual electricity costs based on actual tariffs and has been undertaken using the domestic single rate tariff and domestic 'hot water tariff'[22]. The top down approach involves disaggregating annual electricity costs based on the ABS's electricity price index.

These approaches, and our approach to replicating the analysis in NSW and Queensland, are described in more detail below.

A.1.1. Bottom up approach

This approach involves using the individual retail and network domestic single rate tariffs for each distribution business to estimate annual electricity costs based on average consumption profiles (i.e. a customer consuming the average level of domestic consumption in each year from 1998-99 to 2010-11).

We undertook this analysis with both the domestic single rate tariff and the domestic hot water tariff to test the sensitivity and robustness of our findings.

The steps involved in the bottom up approach for a customer in each distribution zone are set out below (using the single rate tariff analysis as an example):

1. Using the retailer's annual standing offer (i.e. default) domestic single rate tariff, determine the annual retail electricity cost for each year from 1998-99 to 2010-11 paid to the retailer by a domestic customer consuming the average amount of electricity each year. The average amount of electricity represents the average consumption of a customer in South Australia for each year.

2. Using the domestic single rate DUOS tariff, determine the annual distribution network cost component for each year from 1998-99 to 2010-11 attributable to a domestic customer consuming the average amount of electricity each year.

3. Repeat the above step using the domestic single rate TUOS tariff to determine the annual transmission network cost component for each year from 1998-99 to 2010-11.

[22] This refers to customers under the domestic single rate tariff with separate controlled load tariff.

4. The non-network cost attributable to a customer consuming the average amount of electricity for each year is calculated as the difference between the annual retail electricity cost and the sum of the distribution network and transmission network costs.

New South Wales

In NSW, we were constrained by the unavailability of network tariff data before 2001-02 due to reasons such as the changing number and structure of tariffs over time, distribution businesses having merged, and significant changes in data storage platforms.

For these years, we consequently interpolated the network tariffs based on average annual price movements allowed by the regulator for the relevant year, using the approved P-nought and X factor adjustments. Refer to the Section A.3 for more detail.

Queensland

As with NSW data, we were also constrained by the unavailability of network tariff data from network businesses in Queensland prior to around 2002. We consequently interpolated network tariffs for missing years based on approved P-nought and X factors adjustments or, where these were not available, changes in CPI.

In addition, our analysis in Queensland is complicated by the Uniform Tariff Policy, which ensures that all customers in Queensland pay no more than regulated prices available to customers in southeast Queensland. This means that the Queensland Government provides a Community Service Obligation (CSO) payment to subsidise the cost of electricity in regional Queensland.[23] The Queensland Government provided CSO payments of approximately $250 million to the electricity retailer in regional Queensland in 2009-10.[24]

This creates a distortion in the disaggregation of electricity costs in Queensland because retail electricity prices in regional Queensland are not fully reflective of the true network costs. The Uniform Tariff Policy requires a retailer in regional Queensland to set the same price for electricity as a retailer in southeast Queensland, despite the difference in network costs incurred in delivering electricity in these two areas.

This creates issues when it comes to disaggregating the change in domestic retail electricity prices in Queensland down to the network and non-network components, for example:

- The annual retail electricity costs produced by our analysis are lower than the fully cost-reflective prices;
- The network component is cost-reflective;
- As the non-network component of electricity prices is estimated as the difference between the retail price and the network component, the non-network component appears lower than it would be if retail prices were cost-reflective; and
- In practice, the distortion is corrected by the CSO payment which ensures that the incumbent retailer in regional Queensland recovers its network costs, while charging a retail price to its domestic customers which is lower than cost-reflective levels.

To correct this distortion, we scaled down the network cost component in Queensland.

Based on our other work in the electricity sector, we understand that the network component typically comprises between 45 per cent and 55 per cent of retail electricity costs in

[23] http://www.ergon.com.au/your-home/accounts--and--billing/electricity-prices
[24] http://www.dme.qld.gov.au/zone_files/Electricity/ergon_energy's_role_in_a_competitive_queensland_electricity_market.pdf

Queensland. This understanding is consistent with the findings of the QCA, which estimated that network costs account for 47% of the total cost of supplying electricity in 2009-10.[25]

We have thus normalised our estimate of the network cost component in Queensland, setting annual network costs to account for 50 per cent of the annual retail electricity price in 2010-11. We then extrapolated the normalised network cost in 2010-11 back to 1998-99 using the actual observed trend in network costs.

As a result, all charts on Queensland in this report reflects the trend in network costs over time, rather than the actual dollar value. Accordingly, the dollar values should be interpreted with some caution. However note that the final electricity cost for Queensland is correct.

A.1.2. Zero load growth for typical customer scenario

This scenario has been analysed to attempt to determine the impact that consumption growth, or load growth, has had on the cost of the network component each year. To do this, we would have to determine what network charges would be if average consumption remained fixed from 1998-99 to 2010-11.

However without access to a network business's tariff model, this is not possible due to the complex nature of determining network charges.

Network businesses typically set tariffs based on two factors: the total amount of costs to recover through its network charges and the volume of electricity it distributes.

- Costs – if average consumption was fixed from 1998-99 to 2010-11, a network business would not necessarily have invested the same amount to expand or upgrade its network. This would mean that it is likely that the network business would set a lower network charge than otherwise because the total amount of costs to recover would be lower.

- Volume – given price is broadly a function of costs and volume, if a network business distributes less electricity than expected (for example, if growth in average consumption is zero), it would most likely set a higher network charge to ensure it recovers its costs.

Whether network charges would be higher or lower than otherwise would depend on which of these two opposing impacts (lower costs to recover versus lower volumes from which to recover costs) is stronger. This would require considering whether network investment in capital projects would have taken place based on the lower consumption profile which would be a complex process which we could not undertake with any certainty.

As a result, we simplified the analysis to focus on the annual electricity costs paid by the typical customer from 1998-99 to 2010-11 if he or she fixed consumption at 1998-99 levels, assuming no change in retail and network charges.

That is, this reflects the impact of load growth on one customer, rather than the impact on the annual cost of the network component of electricity.

The results should therefore be interpreted with some caution.

A.1.3. Top down approach

This approach relies on the ABS electricity price index to estimate average annual retail electricity costs for domestic customers, and only requires the aggregation of electricity costs from individual tariffs for one year.

The top down approach consists of the following steps:

[25] Queensland Competition Authority, Final Decision on 2009-10 Benchmark Retail Cost Index, June 2009, page 5.

1. Using the retailer's 2010-11 standing offer (i.e. default) domestic single rate tariff, determine the annual retail electricity cost paid to the retailer each year by a domestic customer consuming the average amount of electricity in 2010.

2. Extrapolate the annual retail electricity cost in 2010-11 back to 1998-99 in accordance with the ABS electricity price index to estimate average annual retail electricity costs for domestic customers consuming the average amount of electricity for each year from 1998-99 and 2009-10.

3. Estimate the annual distribution network cost component and transmission network cost component attributable to customers consuming the average amount of electricity for each year from 1998-99 to 2010-11 by using the domestic single rate DUOS and TUOS tariffs. This is calculated in an identical manner as under the bottom up approach.

4. The non-network cost attributable to a customer consuming the average amount of electricity for each year is calculated in an identical manner as under the bottom up approach.

We elected to use the results of our top down approach as a cross check on the results of our bottom up approach. We did this for a number of reasons:

- The ABS electricity price index is a well-known and relied upon measure of retail electricity prices in Australia over time;

- There is a degree of uncertainty about how the ABS's price index is precisely calculated (e.g. which types of customers it applies to, does it include customers on market offers and default offers); and

- It is not as precise as the bottom up approach which involves using actual retail tariffs.

Nevertheless, we undertook a top down analysis to disaggregate annual electricity costs in South Australia, NSW and Queensland as a check of the robustness and sensitivity of our main findings.[26]

A.2. Data sources

All the data we used in our analysis is publicly accessible. The South Australian electricity network businesses provided us with confidential data on consumption by tariff type to validate our analysis, but it has not been used in our analysis or presented in our findings. All of the findings are able to be replicated using publicly accessible information.

Table 7 shows the key data sources we used in our analysis.

Table 7 Data sources by State

	South Australian	New South Wales	Queensland
Retail standing offer tariff data	South Australian Government Gazette	Retail businesses (on request)	QLD Government Gazette
Network charge tariff data	Network businesses (on request)	Network businesses (on request)	Network businesses (on request)
Average consumption data (per customer)	ESAA	ESAA	ESAA
Electricity price index	ABS	ABS	ABS
Inflation data	ABS	ABS	ABS

Note: ABS = Australian Bureau of Statistics; ESAA = Energy Supply Association of Australia;

[26] In all three States, the results of the top down analysis are consistent with our findings from the disaggregation of costs under the domestic single rate tariff.

A.3. Key assumptions

- Network charges refer to NUOS tariffs, which include both DUOS and TUOS tariffs.
- Unless otherwise stated, all prices and costs exclude GST to allow an appropriate comparison of prices and costs over time from 1998-99 to 2010-11.
- In this report, prices and consumption volumes are expressed on a financial year basis. This is consistent with the regulatory years (i.e. twelve-month periods) over which electricity prices and regulated revenues are determined under the regulatory regime in each of these States. We also converted data expressed on a partial year terms into financial year terms on a pro rata basis.
- In some years, annual data on historical network tariffs were not available due to factors such as the merging of distribution businesses or significant changes in data storage platforms.[27] In these instances, we interpolated the tariffs based on average annual price movements allowed by the regulator for the relevant year, using the approved "P-nought" adjustments and "X factors" [28] and taking into account changes in CPI.[29] The P-noughts and X factors for each regulatory period are available from distribution determinations publicly available from the website of the relevant regulator.
- As referred to in Section 3.1, there were numerous pass through events and network price adjustments in South Australia between 1998-99 and 2010-11. We assumed these costs to be included as follows.

Table 8 Pass through events and network price adjustments included in distribution costs

Event	Years	Description
Outage Management System pass through event	January 2004, and in 2004-05	ESCOSA required ETSA Utilities to install an Outage Management System to more accurately measure the reliability of supply experienced by electricity customers in South Australia. These costs were passed through to consumers in 2003-04 and 2004-05.
Full Retail Contestability pass through event	From January 2003, and in 2003-04 and 2004-05	ETSA Utilities became responsible for providing metering services to customers in South Australia with types 5, 6 and 7 metering as part of the introduction of FRC to domestic customers on 1 January 2003. This resulted in ETSA Utilities incurring significant capital and operating expenditure. These costs were passed through to consumers in 2003-04 and 2004-05.
66kV undergrounding pass through event (August 2007)	2009-10	Cost pass through approved by ESCOSA for the undergrounding of 66kV powerlines. These costs were passed through to consumers in 2009-10.
Distribution licence pass through event (August 2007)	2009-10	Cost pass through approved by ESCOSA to reflect the increase in the ETSA Utilities annual distribution licence fee. These costs were passed through to consumers in 2009-10.
Photovoltaic rebate pass through event (September 2008)	2009-10	Cost pass through approved by ESCOSA relating to the approval of the *Electricity (Feed-In Scheme – Solar Systems) Amendment Bill 2008* which required ETSA Utilities to pay small customers 44c per kWh for every

[27] The following tariff data was not available: EnergyAustralia tariffs 1998-99 to 2001-02, Integral Energy tariffs 1998-99 to 2000-01, Country Energy tariffs 1998-99 to 2000-01, Energex tariffs 1998-99 to 2001-02 and Ergon Energy tariffs 1998-99 to 2002-03.
[28] A "P-nought adjustment" is the term given to the percentage increase or decrease in the weighted average of an electricity network business's annual tariffs allowed by the regulator in the first year of a regulatory period. "X factors" are the percentage increase or decrease allowed in all subsequent years of a regulatory period (from the second to the fifth year).
[29] Escalation of prices under *CPI–X* regulation, where a positive value for X indicates a real price decrease under the *CPI–X* formula.

Event	Years	Description
		kWh of electricity generated from a small photovoltaic generator that is fed back into the network. These costs were passed through to consumers in 2009-10.

Table 9 Pass through events and network price adjustments included in transmission costs

Event	Years	Description
TUOS rebate	1999-00 to 2001-02	Rebate of ElectraNet's TUOS charges.
TUOS pass through	2002-03 to 2004-05	Pass through of the change in ETSA's network charges arising from new transmission costs allowed in the ACCC's revenue cap decision for ElectraNet from January 2003.

- While we recognise that under a weighted average price cap form of price control, P-nought and X factor adjustments refer to the real percentage change allowed in the *weighted average* of a network business's entire suite of tariffs (rather than any individual tariff), and under a revenue cap these represent the real percentage change allowed in the annual revenue requirement, we consider that on balance, it is often likely to be a reasonable proxy for the percentage change in domestic tariffs. See Appendix B for detail of the P-noughts and X factors allowed by the regulator in previous determinations.

- Where a network business formed after 1998-99, network prices and X factors for each year from 1998-99 to the year of the entity's formation have been estimated as the average of the prices and X factors of the preceding businesses, typically weighted by the value of the capital base. In this report, we used this approach for Country Energy prior to its formation in 2001 and for Ergon Energy prior to its formation in 1999.

- Figures presented in this report may be affected by rounding.

Appendix B: Other results

B.1. South Australian preliminary 2011-12 results

Background

In August 2011, regulated electricity prices paid by South Australian households increased by 17.4 per cent, according to ESCOSA's Annual Performance Report 2010-11.[30] There has since been considerable media coverage about the increases in electricity prices in South Australia.[31]

As a result, we extended our analysis of South Australian domestic electricity prices to include the current year 2011-12, based on the electricity retail standing and default contract tariffs from 1 August 2011 and ETSA Utilities' network tariffs from 1 July 2011.

As context, the current electricity distribution regulatory period in South Australia commenced in 2010-11. The distribution determination allowed ETSA Utilities a large price increase, commensurate with an X factor of -18.10 per cent,[32] in the second year of the regulatory period (i.e. 2011-12).

To undertake this analysis for the current year 2011-12, we require data on average domestic consumption for this year. However, this data is not available because 2011-12 is not complete. We consequently relied on consumption forecasts in the AER's distribution determination, which forecasts a decrease in energy sales per customer (i.e. average consumption) of 2.9 per cent for ETSA Utilities in 2011-12.[33]

This forecast reflects the decrease in average consumption across ETSA Utilities' entire business. In other words, this includes industrial and business customers. Our analysis focuses on prices paid by the typical domestic customer so it is necessary to forecast the change in average domestic consumption in the current year 2011-12.

We have consulted with ETSA Utilities to develop an appropriate forecast for domestic consumption in South Australia in 2011-12, which was based on the energy demand forecasts contained in the AER and Australian Competition Tribunal's (the Tribunal) determination. In particular, we consider that the forecast for domestic customers should consider the expected declining usage by these customers from the response to price increases and the increased domestic use of photovoltaic cells in 2011-12. As a result, we assumed average consumption in the domestic sector in South Australia will decline by 4 per cent in 2011-12.

Preliminary findings

Figure 12 shows the trend in average domestic South Australian electricity prices including 2011-12 retail and network tariffs.

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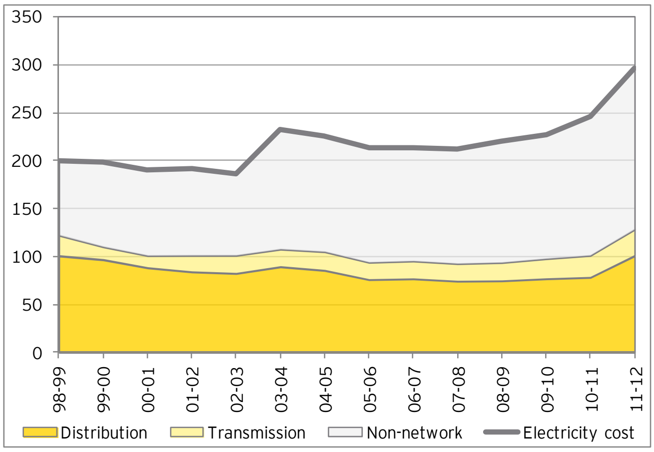
[30] ESCOSA, Annual Performance Report 2010-11: SA Energy Supply Industry – Energy Price Fact Sheet
[31] For example, refer to "Electricity prices up $500 – and more pain is on the way", The Advertiser (South Australia), 23 November 2011; and "Power bills up 44pc in three years", ABC News Online, 23 November 2011.
[32] The AER's distribution determination was superseded by the Tribunal's decision. Refer to Amendments to distribution determination – Australian Competition Tribunal orders, 19 May 2011, page 2. Note that positive values for X indicate a real price decrease and negative values indicate a real price increase.
[33] This figure was calculated from Table 5 of the Tribunal's orders. Average consumption (per customer) declined from 14.0kWh p.a. in 2010-11 to 13.6kWh p.a. in 2011-12. Refer to Amendments to distribution determination – Australian Competition Tribunal orders, 19 May 2011, page 5.

Figure 12 South Australia electricity costs by component 1998-99 to 2011-12 ($ per MWh, real 2010)



Source: Ernst & Young analysis

SA - 1998-99 to 2011-12

- 48% increase in final retail price
- 0.2% increase in distribution costs
- 29% increase in transmission costs
- 116% increase in non-network costs

Table 10 shows the change in dollar terms and percentage terms of the components of average South Australian electricity costs between 1998-99 and 2011-12.

Table 10 South Australia electricity costs by component – 1998-99 vs. 2011-12 ($ per MWh, real 2010)

	1998-99	2011-12	Change ($)	Change (%)
Final retail price	$200	$296	+$96	+48%
Network	$122	$128	+$6	+5%
Distribution	$101	$101	+$0.2	+0.2%
Transmission	$21	$27	+$6	+29%
Non-network	$78	$168	+$90	+116%

Figures may be affected by rounding. Source: Ernst & Young analysis

The reductions in network costs and distribution costs between 1998-99 and 2010-11 were sufficiently strong such that only in 2011-12 are distribution costs for the typical domestic customer ($ 101 per MWh) expected to 'claw back' the cost reductions and return to 1998-99 levels ($101 per MWh).

B.2. Comparison of 2010-11 prices

We have also compared electricity prices in the most recent completed year in South Australia, NSW, Queensland (i.e. for these States, this year is 2010-11) and Victoria (i.e. 2010).

Results on a per MWh basis are presented in Table 11, while per customer results are presented in Table 12.

Per MWh

Table 11 Electricity costs per MWh 2010-11 ($ per MWh, real 2010)

	South Australia	NSW	Queensland	Victoria
Final retail price	$246	$215	$206	$223
Network	$101	$113	$108	$84
Distribution	$78	-	-	$76
Transmission	$23	-	-	$10
Non-network	$145	$103	$98	$139

Victoria results reflect electricity costs in 2010. Figures may be affected by rounding.
Source: Ernst & Young analysis

Per customer

Table 12 Electricity costs per customer 2010-11 ($ per customer, real 2010)

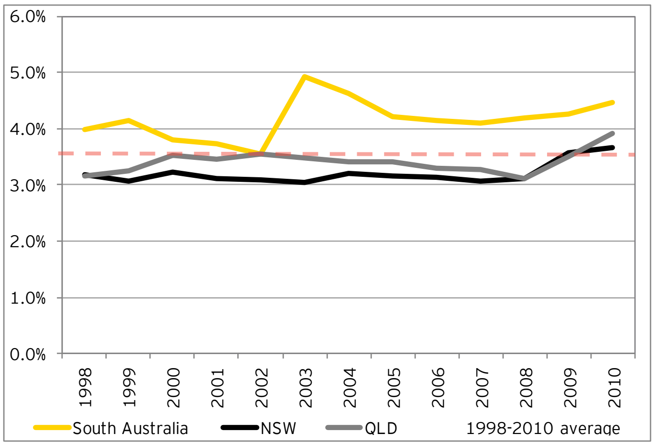
	South Australia	NSW	Queensland	Victoria
Final retail price	$1,549	$1,503	$1,608	$1,273
Network	$636	$785	$844	$477
Distribution	$493	-	-	$412
Transmission	$143	-	-	$66
Non-network	$913	$718	$764	$796

Victoria results reflect electricity costs in 2010. Figures may be affected by rounding.
Source: Ernst & Young analysis

B.3. Typical annual bill

Figure 13 shows the average annual electricity bill as a proportion of disposable income[34] in South Australia, NSW and Queensland from 1998-99 to 2010-11.

Figure 13 Average annual electricity bill as a proportion of disposable income 1998-99 to 2010-11 (nominal)



Note: Results expressed on financial year basis (i.e. beginning 1 July).
Source: Ernst & Young analysis, ABS, ATO.

The proportion of disposable income spent by the typical domestic customer on electricity each year has increased in all three States in recent years.

In South Australia, the proportion spent by typical domestic customers is somewhat higher than those in NSW and Queensland. However average disposable income in NSW and Queensland is higher than in South Australia.

However this only addresses the domestic customer with an average consumption profile. If this customer increased consumption by 10 per cent in 2010, the annual electricity bill would increase by:

- 8.9 per cent ($138) in South Australia;
- 8.7 per cent ($131) in NSW; and
- 8.0 per cent ($129) in Queensland.

[34] Disposable income is calculated as income measured by the ABS average full time total earnings less tax payable in accordance with the ATO's individual income tax rates from 1998-99 to 2010-11.

B.4. Zero load growth

This scenario has been analysed to attempt to determine the impact that consumption growth, or load growth, has had on the cost of the network component each year for the average domestic customer in NSW and Queensland. We adopted a similar approach to our analysis of the zero load growth scenario in South Australia. Our findings are presented below.

Table 13 Annual distribution costs of a typical customer in NSW ($ per customer, real 2010)

	1998-99	2010-11	Change ($)
Typical customer	$459	$785	+$326
Zero load growth	$459	$820	+$361

Note: Figures may be impacted by rounding. Source: Ernst & Young analysis

Table 14 Annual distribution costs of a typical customer in Queensland ($ per customer, real 2010)

	1998-99	2010-11	Change ($)
Typical customer	$358	$844	+$511
Zero load growth	$358	$768	+$410

Note: Figures may be impacted by rounding. Source: Ernst & Young analysis

The results suggest that holding consumption constant between 1998-99 and 2010-11, the annual network bill of a typical domestic customer increases significantly in both States.

In NSW, average domestic consumption decreased between 1998-99 and 2010-11. Therefore the analysis indicates that a 'zero load growth customer' ($820) would pay more than a typical customer ($785) in 2011-11. This is because the distributors have to recover the 'same costs' over a lower number of sales (i.e. because average consumption has fallen).

An important point to note is that investment in the augmentation of a distribution network is driven by peak demand growth, not energy demand growth. It is therefore likely that growth in total energy demand may be flat or indeed falling, but if peak demand is growing then this will drive the need for investment in network capacity.

This point has been supported by stakeholders such as the Australian Energy Market Commission (AEMC)[35] and Ausgrid.[36] In particular, the AEMC stated that peak demand has grown by 3.5 per cent per annum since 2005, compared to energy demand growth of 1.2 per cent per annum. Meanwhile according to Energex,[37] since 2001-02, peak demand growth has been approximately double the rate of growth in energy volumes.

The zero load growth analysis above (i.e. zero growth in energy demand) does not take into account changes in peak demand. As a result, the results should be interpreted with caution.

[35] AEMC, Strategic Priorities for Energy Market Development Discussion Paper, 2011, page 4
[36] Ausgrid, Response to the AEMC review of strategic priorities for Energy Market Development, May 2011, page 3
[37] Energex, Presentation to the Clean Energy Council Energy Efficiency Seminar, June 2009, slide 5, available online at: http://www.cleanenergycouncil.org.au/cec/mediaevents/Past-Events/EE-presentations/mainColumnParagraphs/0/text_files/file3/TERRY%20MCCONNELL.pdf

B.5. Regulatory decisions

The tables below show the P-noughts and X factors allowed by the regulator to the distribution network businesses in South Australia, NSW and Queensland.

Table 15 Real allowed P-noughts and X factors by distributor in South Australia 1999-00 to 2014-15 (%)

	ETSA Utilities	Regulatory period
1999-00*	3.94	1999-00 to 2004-05: Electricity Pricing Order
2000-01*	5.43	
2001-02*	2.73	
2002-03*	2.73	
2003-04*	2.73	
2004-05*	2.73	
2005-06*	4.00	2005-06 to 2009-10: ESCOSA
2006-07*	-0.80	
2007-08*	-0.80	
2008-09*	-0.80	
2009-10*	-0.80	
2010-11	-12.14	2010-11 to 2014-15: AER
2011-12	-18.10	
2012-13	-7.00	
2013-14	-7.00	
2014-15	-0.89	

* Note that up until and including 2009-10, P-nought and X factor adjustments were determined in distribution price determinations in the Electricity Pricing Order and by ESCOSA. From 2009-10 onwards, this responsibility was assumed by the AER. Positive values for X indicate a real price decrease and negative values for X indicate a real price increase. Results incorporate ETSA Utilities successful Tribunal appeal with consequential impacts on X factor values from 2011-12 to 2014-15.
Source: South Australia EPO October 1999, Electricity Distribution Price Determination 2005-10 (ESCOSA), Final Decision on South Australian Distribution Determination 2010-11 to 2014-15 (AER).

Table 16 Real allowed P-noughts and X factors by distributor in New South Wales 1995-96 to 2014-15 (%)

	Ausgrid (EnergyAustralia)	Endeavour (Integral Energy)	Essential (Country Energy)	Regulatory period
1998-99*	3.50	3.50	1.45	1995-96 to 1998-99: IPART
1999-00*	0.00	0.00	0.00	1999-00 to 2003-04: IPART
2000-01*	0.86	1.47	-2.26	
2001-02*	0.86	1.47	-2.26	
2002-03*	0.86	1.47	-2.26	
2003-04*	0.86	1.47	-2.26	
2004-05*	-7.00	-5.00	-7.00	2004-05 to 2008-09: IPART
2005-06*	-1.60	-1.50	-2.50	
2006-07*	-1.60	-1.50	-2.50	
2007-08*	-1.60	-1.50	-2.50	
2008-09*	-1.60	-1.50	-2.50	
2009-10*	-17.86	-12.58	-13.41	2009-10 to 2013-14: AER
2010-11	-12.00	-7.00	-13.31	
2011-12	-12.00	-7.00	-12.00	
2012-13	-12.00	-2.00	-12.00	
2013-14	-8.00	0.00	0.00	
2014-15	-	-	-	-

* Note that from 1998-99 to 2008-09, P-nought and X factor adjustments were determined in distribution price reviews by IPART. From 2009-10 onwards, this responsibility was assumed by the AER. X factors for 2014-15 are not known as this forms part of the next regulatory period (2014-15 to 2018-19). Positive values for X indicate a real price decrease and negative values for X indicate a real price increase.
Source: NSW electricity distribution price determinations March 1996, December 1999, 2004-05 to 2008-09 (IPART) Final Decision on NSW distribution determination 2009-10 to 2013-14 (AER).

Table 17 Real allowed P-noughts and X factors by distributor in Queensland 1995-96 to 2014-15 (%)

	Energex	Ergon	Regulatory period
1998-99*	No X factors available, prices extrapolated according to changes in CPI	No X factors available, prices extrapolated according to changes in CPI	1995-96 to 1999-00: QLD Government
1999-00*			
2000-01*	-9.50	-18.80	2000-01 to 2004-05: QCA
2001-02*	0.50	-5.90	
2002-03*	0.50	-0.30	
2003-04*	0.50	-0.30	
2004-05*	0.50	-0.30	
2005-06*	-11.90	-30.80	2005-06 to 2009-10: QCA
2006-07*	-11.90	-5.70	
2007-08*	-11.90	-5.70	
2008-09*	-11.90	-5.70	
2009-10*	-5.50	-5.70	
2010-11	-18.20	-29.61	2010-11 to 2014-15: AER
2011-12	-7.90	-5.10	
2012-13	-7.90	-5.10	
2013-14	-7.90	-5.10	
2014-15	-7.90	-5.10	

* Note that from 2000-01 to 2009-10, P-nought and X factor adjustments were determined in distribution price reviews by the QCA. From 2010-11 onwards, this responsibility was assumed by the AER. Positive values for X indicate a real price decrease and negative values for X indicate a real price increase. Data on X factors for the 1998-99 to 1999-00 regulatory period could not be obtained and where necessary, network tariffs have been escalated in accordance with changes in CPI.

Source: Final Determination on Regulation of Electricity Distribution May 2001 and April 2005 (QCA), Final Decision on Queensland distribution determination 2010-11 to 2014-15 (AER).

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