Australian Energy Market Commission

RULE CHANGE

# 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

**Rule Proponents**

Australian Energy Regulator
Energy Users Rule Change Committee - Amcor, Australian Paper, Rio Tinto, Simplot, Wesfarmers, Westfield and Woolworths

**Commissioners**

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2 March 2012

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**About the AEMC**

The Council of Australian Governments, through its Ministerial Council on Energy (MCE), established the Australian Energy Market Commission (AEMC) in July 2005. The AEMC has two principal functions. We make and amend the national electricity and gas rules, and we conduct independent reviews of the energy markets for the MCE.

# Executive Summary

## Rule change requests

In September 2011, the Australian Energy Regulator (AER) submitted two rule change requests seeking to amend rules for the economic regulation of network services. The areas identified by the AER as deficient and requiring improvement are:

- for electricity: the capital and operating expenditure framework, capital expenditure incentives, cost of capital provisions, and the efficiency of the regulatory process as set out in the National Electricity Rules (NER); and
- for gas: the rate of return provisions in the National Gas Rules (NGR).

In October 2011, the Energy Users Rule Change Committee (EURCC) a group of large energy users comprising Amcor, Australian Paper, Rio Tinto, Simplot, Wesfarmers, Westfield and Woolworths, submitted a rule change request seeking to address one area of the determination of the rate of return on capital in the NER; being the methodology for the calculation of the return on debt component.

## Approach

This directions paper explains the Australian Energy Market Commission's (AEMC or Commission) initial positions on, and sets out its next steps to progress, the rule changes requests from the AER and the EURCC.

The AEMC has developed its initial positions on the proposals in the rule change requests guided by the requirements under the National Electricity Law (NEL) and the National Gas Law (NGL). The NEL and the NGL provide that the AEMC may only make a rule if it is satisfied that the rule will or is likely to contribute to the achievement of the National Electricity Objective (NEO) or the National Gas Objective (NGO). In making this assessment the Commission must also take into account the revenue and pricing principles in the NEL/NGL. At a high level, this means that investing in and operating the networks is in the long term interests of consumers when reliability and safety standards are met at the efficient long term cost.

These Laws reflect a particular institutional governance structure and define certain roles for the Commission as rule maker and the AER as regulator.

In addition, the price and service outcomes experienced by consumers are a function of three drivers:

- the legal and regulatory framework;
- the application of the framework by the regulator; and

- the corporate governance of electricity network service providers (NSPs) and gas service providers.

The efficiency of NSPs and gas service providers in large part depends on the way in which the drivers work together. This leads to two conclusions. First, regulation cannot compensate for weaknesses in corporate governance arrangements. Secondly, to the extent that network outcomes are considered to be inappropriate it is necessary to understand the degree to which these outcomes are a product of the rules, as opposed to other drivers. This is particularly relevant in assessing these rule change requests.

The AEMC has developed its initial position after undertaking consultation with stakeholders and undertaking its own analysis. The Commission also engaged independent consultants Professor Stephen Littlechild, Professor George Yarrow and SFG Consulting (Professor Stephen Gray and Dr Jason Hall) to prepare reports on the issues raised in the rule change requests. Published with this directions paper are their reports. These reports have informed the Commission's views.

## Capital expenditure (capex) and operating expenditure (opex) allowances (electricity only)

### AER's proposal to set forecasts

The AER has recommended changes to address issues relating to the process by which forecasts of efficient capital expenditure (capex) and operating expenditure (opex) are approved. Most significantly, the AER's electricity rule change request refers to restrictions on the AER's ability to reject NSPs' capex and opex forecasts and the requirement that the regulator must accept a forecast if it reasonably reflects certain criteria listed in the NER.[1] The AER considers that the rules invite upwardly biased forecasts and limit its ability to interrogate and amend forecasts provided by NSPs. The AER proposes amendments to the NER to set its own estimate of capex and opex, using a range of inputs.

### AEMC initial position

The Commission will undertake two streams of analysis to determine whether there is a problem with the capex and opex allowances provisions in the NER and, if so, whether any changes to the NER are required. These streams are as follows:

- The first is to confirm that the policy intent regarding the role and power of the AER to test NSP's forecasts, established by the Commission in 2006, remains appropriate.[2] This will be undertaken by comparing that policy intent with the actual practices of, and outcomes experienced by, other regulators in Australia and overseas.

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1 The criteria against which the AER must assess such a forecast are that the forecast must reasonably reflect the efficient costs a prudent operator in the circumstances of the relevant NSP would require to meet the objectives, and a realistic expectation of the demand forecast and cost inputs.

2 AEMC, Economic Regulation of Transmission Services, Rule Determination, 16 November 2006.

- The second is to analyse any further evidence provided by stakeholders in response to this directions paper on the drivers of increases in network costs and the relationship between the framework for capex and opex allowances and increases in network charges. The rule change requests have been made in an environment of rising retail electricity prices. Increases in the network components of those prices have contributed significantly to the increases and are expected to continue to do so.[3] Stakeholders have provided limited analysis to support their positions on the drivers of increasing network costs, the efficiency of NSPs, and the link between network cost increases and the AER's powers under the NER. The AEMC encourages stakeholders to address this analytical gap as part of their submissions on the directions paper.

## Capital expenditure incentives (electricity only)

### AER's proposal regarding capital expenditure above original forecasts

The AER has raised issues relating to incentives that can be placed on NSPs to spend no more than a necessary and efficient level of capex and opex. Currently under the NER, all actual capital expenditure incurred within a regulatory control period must be automatically rolled into the asset base at the start of the next period, regardless of whether the expenditure is greater than the amount allowed for in the regulatory determination and whether it is efficient. The AER considers that this roll forward mechanism creates incentives for NSPs to incur more than efficient levels of capex, particularly in the later years of a regulatory control period. One of the factors relevant to consider here, in the AER's view, is whether the regulatory rate of return is higher, lower or equal to the true required rate of return. The AER proposes for inclusion in the rules a sharing mechanism that would apply to any expenditure above the regulatory allowance. 60 per cent of this expenditure above the allowance would be rolled into the regulatory asset base for the next regulatory control period, with the remainder excluded from that asset base and funded by shareholders. The AER believes that such a mechanism would strengthen the incentives on NSPs to incur no more than what is efficient.

### AEMC initial position

The Commission is of the view that the regulatory mechanisms to incentivise efficient capex should not be designed to address rate of return matters. Leaving the cost of capital aside, there is no incentive in the NER to spend more than the capex allowance, although there is an incentive to defer capex until the end of the regulatory control period. Capex above the allowance in the regulatory determination is not subject to any regulatory scrutiny or supervision at all, which creates a risk that it may be inefficient. Factors outside of the NER may provide incentives for capex beyond the allowance. The AEMC considers that this is a deficiency and the rules could be

3 Refer to AEMC, Possible Future Retail Price Movements: 1 July 2011 to 30 June 2014, Final Report, Sydney, for detail on the projected contributions of network prices to overall residential electricity prices.

enhanced to allow for some scrutiny of, or incentives relating to, actual expenditure which differs from the forecasts.

There has been considerable concern expressed regarding the AER's proposed solution – being the 60/40 sharing mechanism on expenditure above the regulatory allowance. The Commission shares a number of them. They include that this option is very prescriptive and does not allow for differences between NSPs or for the mechanism to be refined over time. Also, it does not address the incentive to defer capex until the end of the regulatory control period. The Commission will explore other options for dealing with the problems it has identified. This will involve undertaking further work to understand the causes and nature of capex above the regulatory allowance and their relationships with the uncertainty regime in the NER (being capex reopener, cost pass through and contingent project provisions). It will also consider the contribution of overspends to subsequent price increases.

## Determination of rate of return on capital (electricity and gas)

### AER's proposed framework

Together, the AER electricity and gas rule change requests consider the different arrangements for determining the rate of return on investment in electricity distribution, electricity transmission and gas. The AER considers that the frameworks for electricity distribution and gas have been problematic because they have required the repeated assessment of similar arrangements and evidence at each determination/access arrangement process, creating administrative burden. The AER proposes a single framework for electricity and gas which most closely aligns with the current framework for electricity transmission; that is, the outcomes of the (up to 5 yearly) periodic rate of return reviews must apply and cannot be departed from in subsequent determinations and access arrangements made until the next review. The AER's proposal would also provide it with increased discretion in how to determine certain individual parameters forming part of the rate of return and would remove the need for persuasive evidence before amending them. The effect of these changes would also be to exclude merits review of rate of return decisions made under the NER and the NGR. The single framework would also incorporate the changes below.

### Electricity – cost of debt

Currently the NER require a form of benchmark be used to assess the cost of debt. The AER states that establishing a benchmark has become difficult under changing financial market conditions. The AER proposes that the methodology for setting the debt risk premium should be included in the periodic rate of return reviews undertaken by the AER, rather than being prescribed in the rules. This proposal is contested by the EURCC for the electricity frameworks. The EURCC's rule change request proposes a new rules-prescribed methodology for calculating the cost on debt, having regard to the "actual" debt costs of network services providers. The return on debt for government-owned NSPs would be determined differently to privately-owned NSPs.

**Gas – specifications of post-tax models and CAPM**

Currently the NGR do not specify a particular framework for determining the rate of return. The AER states that this creates uncertainty and there is an administrative burden in considering alternative models, being pre or post-tax revenue models The AER has consistently applied a nominal post-tax framework. While the method for determining the return on equity is not set out in the NGR, the capital asset pricing model is well accepted and therefore, in the AER's view, unlikely to be departed from the medium to long term. The AER proposes that the NGR would prescribe that the rate of return be calculated as a nominal post-tax vanilla weighted average cost of capital (WACC), using the capital asset pricing model to determine the return on equity. Thus, the NGR would be in line with the NER (as amended).

**AEMC initial position**

Of all the issues presented in the rule change requests, the rate of return has the greatest bearing on prices ultimately paid by consumers of electricity and natural gas.

The AEMC is of the view that the current rules in electricity transmission for determining the rate of return are not satisfactory. In addition, the different rate of return approaches for electricity transmission, electricity distribution and gas appear to lead to discrepancies following the outcomes of merits review appeals.

The prescription in the NER regarding the calculation of the debt risk premium has not been capable of responding to unexpected events, such as the global financial crisis. The electricity transmission framework in chapter 6A is no longer appropriate, given the developments in financial markets since 2008. Even though this framework provides stability and certainty, this appears to be at the expense of a decline in the quality of the rate of return estimates for transmission NSPs over time. The approach for determining a rate of return on investment must provide a level of flexibility to reflect changing circumstances; and take into account prevailing market conditions as they vary. Increased flexibility would provide for decision making that is more attuned to changing market conditions and current approaches in financial theory. The NGR and the Chapter 6 electricity distribution frameworks are more flexible in this regard.

The Commission's initial preference is for a single framework across electricity distribution, electricity transmission and gas, but is open to consider different frameworks for electricity and gas service providers.

While there is a merits review mechanism available in the NEL and the NGL for regulatory determinations and access arrangements, the most significant decisions that make up the regulatory determination or access arrangement, being those relating to the rate of return, should be subject to this mechanism. This is particularly the case if other decisions, which tend not to have such a significant impact on prices overall, are also subject to this mechanism.

The AEMC will be exploring alternative options for rate of return based around flexible approaches rather than prescription, while considering the scope to provide some certainty through the use of guidance on methodologies.

The methodology for determining the cost of debt proposed in the EURCC rule change request includes a number of features, particularly regarding the selection of an appropriate benchmark, which the AEMC considers warrant further consideration. The detail proposed to be included in the rules to determine the cost of debt as part of this rule change request is, however, too prescriptive and rigid. The proposal does not provide the level of flexibility required. A methodology such as this included in the rules would not allow the AER to react to change and respond to changing market conditions in a timely manner. In presenting this methodology the EURCC raises a number of pertinent issues to be considered. The AEMC is considering whether the rules should permit the AER to consider, and if appropriate adopt, an option such as this.

The Commission does not consider the EURCC proposal for different arrangements to apply to government-owned and private sector NSPs for determining the cost of debt is appropriate. This is because it fails to fully recognise the role of competitive neutrality principles. In addition, it does not factor in the impact and role of debt neutrality fees. Also, it could remove the option of any future sale or other divestiture of government-owned NSPs.

## Regulatory processes (electricity only)

### AER's proposal for more effective engagement by stakeholders

The AER has raised a number of issues that largely concern the ability of stakeholders to engage effectively in the regulatory determination process. The AER considers that the regulatory process could be improved to allow stakeholders to engage more effectively in the process. For example NSPs provide submissions on their own regulatory proposals. In the AER's view, this may result in stakeholders having insufficient time to consider additional material from the NSP.

### AEMC initial position

Regulatory process issues must be considered alongside others raised as part of the AER's electricity rule change request, including the capex and opex allowances framework discussed above as well as the interaction of other aspects of the broader framework, including merits review. There are some questions around existing processes and whether all stakeholders have adequate opportunity to contribute to the regulatory process. Of relevance also is whether the AER has sufficient time to make decisions. The Commission will consider possible amendments to the process to allow greater opportunities for stakeholder input and to ensure that the AER has adequate time to make decisions. For example, the overall process could be longer, or an additional consultation step could be added.

## Review of merits review arrangements

Relevant factors in the consideration of these rule change requests are the mechanisms by which decisions made by the regulator may be reviewed; being the merits review

and judicial review provided for in the NEL and the NGL. Energy Ministers have agreed to bring forward to 2012 the review required under these laws on the merits review arrangements[4]. Energy Ministers have indicated their review should complement the AEMC's process in its consideration of these rule change requests.

In considering the rule change requests the AEMC will have regard to the current review mechanisms. If appropriate, the AEMC may make observations or recommendations to the Standing Council on Energy and Resources regarding the possible impacts of any proposed changes to the appeal mechanisms on the NER and NGR.

## Next steps

The AEMC invites written submissions on this directions paper. Submissions may be lodged online via the Commission's website or by mail. Submissions close on 16 April 2012. For submissions to be given full consideration they must be received by this date. Submissions received after 16 April 2012 may not be given full weight.

In addition to inviting written submissions, the AEMC will be holding workshops in Melbourne on Monday 2 April 2012 to discuss the issues raised in the directions paper. Further details about the format of the workshops and how to register are provided on the AEMC website. The workshops will be structured around the issues raised in this directions paper. The Commission will be seeking to promote extensive stakeholder interaction and debate during the workshops.

4 Standing Committee on Energy & Resources Communique – 9 December 2011

# Contents

# 1 Introduction

## 1.1 Purpose

This directions paper sets out the initial positions of the Australian Energy Market Commission (AEMC or Commission) on rule change requests received from the Australian Energy Regulator (AER) and the Energy Users Rule Change Committee (EURCC), a committee of large energy users comprising Amcor, Australian Paper, Rio Tinto, Simplot, Wesfarmers, Westfield and Woolworths. These rule change requests concern a number of issues relating to the economic regulation of network services.

The Commission is seeking stakeholder comments on this directions paper to inform the next stage of its consideration of these rule change requests.

## 1.2 Rule change requests

In September 2011, the AER submitted two rule change requests seeking to amend rules for the economic regulation of network services. The areas identified by the AER as deficient and requiring improvement are:

- for electricity: the capital and operating expenditure framework, capital expenditure incentives, cost of capital provisions, and the efficiency of the regulatory process as set out in the National Electricity Rules (NER); and
- for gas: the rate of return provisions in the National Gas Rules (NGR).

In October 2011, the EURCC submitted a rule change request seeking to address one area of the determination of the rate of return on capital in the NER; being the methodology for the calculation of the return on debt component.

The EURCC's rule change request and the AER's electricity rule change request were consolidated on 3 November 2011 and are being treated together, as one rule change request.

## 1.3 Consultation undertaken to date

The AEMC published the rule change requests with accompanying consultation papers in late October and early November 2011. In response 65 written submissions were received and considered. Submissions are available on the AEMC website. In the week commencing 19 March 2012 the Commission will publish a summary of all issues raised in written submissions.

A public forum, in which key issues were presented by the rule proponents and a number of stakeholders, was held on 23 November 2011. The purpose of the forum was to facilitate discussion on the rule change requests. Presentations made at the forum are available on the AEMC website.

Commissioners and AEMC staff have met with a number of key stakeholders including consumer representatives, network service providers and investors to discuss the rule change request and understand their initial views.

## 1.4 Consultants

The AEMC has engaged three consultants to assist it with (among other things) preparation of this directions paper. These consultants are Professor Stephen Littlechild, Professor George Yarrow and SFG Consulting (SFG). In response to a request from the AEMC, these consultants prepared reports on issues raised by the AEMC. These reports have been published with this directions paper.

In its preparation of this directions paper the Commission has been informed by the material prepared by these consultants.

## 1.5 Lodging submissions on this directions paper

The Commission invites written submissions on any aspect of this directions paper; in particular the specific questions posed. **Submissions must be lodged online or by mail by 16April 2012 in accordance with the requirements set out below.** Submissions that are received after this time may not be given full weight. Where practicable, submissions should be prepared in accordance with the Commission's Guidelines for making written submissions on rule change requests. The Commission publishes all submissions on its website subject to any claim of confidentiality.

All enquiries on this project should be addressed to Richard Khoe, Director, on (02) 8296 7800.

### 1.5.1 Lodging a submission electronically

Electronic submissions must be lodged online via the Commission's website, www.aemc.gov.au, using the "lodge a submission" function and selecting the project reference code ["ERC0134"]. The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated.

Upon receipt of the electronic submission, the Commission will issue a confirmation email. If this confirmation email is not received within 3 business days, it is the submitter's responsibility to ensure the submission has been delivered successfully.

### 1.5.2 Lodging a submission by mail

The submission must be on letterhead (if submitted on behalf of an organisation), signed and dated. The submission should be sent by mail to:

Submissions may be sent electronically through the Commission's website at www.aemc.gov.au or in hard copy to:

Australian Energy Market Commission
PO Box A2449
Sydney South NSW 1235.
Or by Fax to (02) 8296 7899.

The envelope must be clearly marked with the project reference code: ERC0134.

Except in circumstances where the submission has been received electronically, upon receipt of the hardcopy submission the Commission will issue a confirmation letter. If this confirmation letter is not received within 3 business days, it is the submitter's responsibility to ensure successful delivery of the submission has occurred.

## 1.6 Next steps

The Commission recognises the importance of engaging with stakeholders leading up to the publication of the draft rule determination in July 2012. Commissioners and AEMC staff will meet with stakeholders in addition to receiving and reviewing written responses to this directions paper. This engagement is intended to ensure that the problems are fully understood and any amendments to the NER or NGR proposed by the Commission are sound, workable and enforceable.

On Monday 2 April 2012 the Commission will be holding workshops in Melbourne to discuss the issues raised in Chapters 3 to 7 in the directions paper. Further details about the format of the workshops and how to register will be provided on the AEMC website. The Commission will be seeking to promote extensive stakeholder interaction and debate during the workshops.

After reviewing the outcomes of these workshops, the Commission will consider holding further workshops or meetings to discuss some issues and options in further detail prior to making its draft rule determination.

The Commission will also be engaging consultants to advise on a range of matters leading up to the finalisation of the draft rule determinations, and in a number of cases the consultants will be asked to engage directly with stakeholders. At this stage the Commission intends to:

- continue to obtain advice from Professors Littlechild and Yarrow on the range of issues raised in the rule change requests;
- continue to obtain advice from SFG Consulting, and in particular Professor Stephen Gray and Dr Jason Hall, on rate of return on investment issues;
- engage consultants to analyse whether the policy intent set out in the AEMC's final rule determination following its review of the economic regulation of transmission services in 2006 (referred to as "Chapter 6A rule determination")

remains appropriate, in comparison with the practices of regulators in Australia, and also internationally;[5]

- engage consultants to analyse in more detail the drivers for capital expenditure outside of accepted forecasts; and
- engage consultants to analyse in more detail the incentives on electricity transmission and distribution network service providers (NSPs) relating to the use of related parties to provide services, and the incentives and practical impacts of the use of actual or forecast depreciation.

The draft rule determination is scheduled for publication in July 2012 and the final rule determination in October 2012.

## 1.7 Review of merits reviews

The Commission notes that the Standing Council on Energy and Resources (SCER) has brought forward a review of the merits review mechanism to 2012. This is discussed further in section 8.4 below.

Throughout the rule change process the Commission will engage with SCER to coordinate that review with this rule change process.

## 1.8 Structure of this paper

The key issues arising out of these rule change requests, stakeholder consultation and the AEMC's analysis are set out in this directions paper.

The Commission's approach to assessing the rule change requests is set out in Chapter 2. Chapters three to six cover the major areas raised in the rule change requests as follows:

- Chapter 3 - Capital expenditure and operating expenditure allowances (electricity);
- Chapter 4 - Capital expenditure incentives (electricity);
- Chapter 5 - Rate of return frameworks (electricity and gas); and
- Chapter 6 - Cost of debt (electricity and gas)
- Chapter 7- Regulatory process (electricity).

The Chapters address each issue in the relevant major area by providing:

5 AEMC, *Economic Regulation of Transmission Services*, Rule Determination, 16 November 2006; Chapter 6A of the NER relates to electricity transmission; Chapter 6 of the NER relates to electricity distribution.

- some context for the issue being considered;
- a short description of current arrangements;
- a summary of the rule proponent's proposal;
- a summary of key issues raised in submissions;
- analysis of the issue; and
- the Commission's initial position.

Throughout the document are specific questions on which the Commission seeks submissions.

Finally, Chapter 8 provides commentary on issues raised in submissions received during the first round of consultation which are beyond the scope of the matters being considered as part of these rule change requests.

# 2 Assessment Framework

This chapter sets out the Commission's proposed approach to assessing the rule change requests from the AER and the EURCC, as well as explaining its approach to rule making.

## 2.1 Rule making test

The Commission is required to determine whether the rule change requests will or are likely to contribute to the achievement of the National Gas Objective (NGO) or the National Electricity Objective (NEO). The NGO, as stated in the National Gas Law (NGL), is:

> " to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."

The NEO, as stated in the National Electricity Law (NEL) is:

> " to promote efficient investment in, and efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to:
>
> 1. price, quality, safety, reliability, and security of supply of electricity; and
>
> 2. the reliability, safety and security of the national electricity system"

In addition to determining whether the rule change requests will or are likely to contribute to the achievement of the NGO or the NEO, the Commission must take into account the revenue and pricing principles (RPP) in making a rule for or with respect to transmission system revenue and pricing, distribution system revenue and pricing or regulatory economic methodologies. Where the RPP are required to be taken into account, the Commission must consider each of them and determine the weight to be given to them in its decision-making. The RPP under the NEL and the NGL are reproduced in Appendix A.

Under the NEL and the NGL, the AEMC may make a more preferable rule if the AEMC is satisfied that, having regard to the issues raised in the rule change request before it, the more preferable rule will or is likely to *better contribute* to the achievement of the NEO or the NGO (as the case may be) than the original rule change requested.

## 2.2 Context and principles

Demand for electricity and gas is derived from the value consumers attach to the services those products provide. For example, residential consumers use electricity for cooking and gas for heating, while businesses might use electricity or gas as inputs to

production processes. Therefore, efficient and productive electricity and gas sectors, including the network component of these sectors, are important for the wider competitiveness and productivity of the Australian economy. As the 2006 Expert Panel on Energy Access Pricing (Expert Panel) noted, "The significance to the Australian economy of a reliable energy supply at the lowest sustainable prices, and the importance more generally of a reliable and affordable energy supply for modern life, underscore the importance of ensuring an efficient, efficiently priced and reliable supply of energy."[6]

Achieving an efficient supply of energy in the long term requires three economic criteria to be satisfied:

- costs of production are minimised (productive efficiency),
- prices reflect their underlying costs so that the resources used to provide energy services which have an opportunity cost elsewhere in the economy are allocated to their highest valued uses (allocative efficiency), and
- short run costs are balanced with long run investment so that industries make timely changes to technology and products in response to changes in consumer tastes and in productive opportunities (dynamic efficiency).

Under conditions of effective competition, profit incentives on businesses and the ability of consumers to exercise choice would bring about productive, allocative and dynamic efficiency. However, electricity and gas networks are not subject to such competitive forces. Rather they are natural monopoly industries because they are characterised by large upfront capital investments with relatively low incremental costs of operation. This means it is more efficient to have one business providing a single network in a given area rather than two or more businesses duplicating the capital investment. In order to ensure the owners of the networks do not exploit their monopoly positions, the prices they charge or the revenues they can earn for certain services are regulated by the AER. The regulation broadly aims to bring about efficient outcomes akin to those that would be expected if the business was operating in a competitive environment. That is, the costs of providing the service are minimised over the long term (including reducing costs through innovation), prices are reflective of those costs and quality of service matches consumers' preferences.

Such efficient outcomes require efficient investment decisions, which require good planning and long term forecasting. They also require a measure of how consumers value the service that is provided - for example, a safe and reliable supply of electricity. In theory, investment should only take place up to the point where the costs are equal to consumers' value of reliability. However, consumers' value of reliability is hard to measure and it is likely to differ for each consumer. Most jurisdictions of the National Electricity Market (NEM) set reliability standards, which are limits for the percentage of customer demand that can be unserved in a year due to network unavailability.

6 'Expert Panel on Energy Access Pricing - Report to the Ministerial Council on Energy, April 2006, p. 10

As in a competitive market, businesses should be exposed to both the risks and rewards of their investment decisions. Where NSPs and gas service providers (collectively "service providers" in this chapter 2) invest more than is needed to provide the level of service that consumers (or governments/regulators on their behalf) demand, they should not be able to pass through the costs of that investment to consumers - just as in a competitive market, consumers would choose to use a different (more efficient) provider rather than pay the additional costs. Likewise, where investment takes place that is efficient - ie at lowest long term cost - service providers should make a profit on that investment.

In the case of gas and electricity services, regulation needs to recognise that the risks with respect to investment levels are asymmetric: over-investment may lead to redundant capacity and slightly higher prices to pay for it; under-investment might lead to outages, high cost losses of production and safety concerns.[7]

The NER, NGR and broader regulatory framework need to take account of this asymmetric risk, while maintaining value for consumers. In a competitive market, a company that regularly over-charges relative to efficient cost would lose business. Regulation should aim to create similar discipline on a service provider's costs and prices.

## 2.3 Scope and approach

The proposed rules relate to the electricity and gas transmission and distribution services that are regulated. At a high level, the Commission's view is that investing in and operating the networks in the long term interests of consumers means that network reliability and safety standards are met at efficient long term cost. This outcome will be achieved if a number of conditions are met:

1. Demand is met at lowest total system cost
2. Efficient investment in and use of assets takes place:
    (a) Use of existing assets is optimised[8]
    (b) Network is managed to meet changing demand
    (c) Assets are replaced at the end of their useful life[9]
3. Network service providers recover efficient costs

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7 For example, Australian Paper estimates every interruption to its electricity supply costs it a minimum of $1m, regardless of the length of the interruption.

8 We use the term optimise in this context to refer to service providers making optimum decisions regarding the use of their assets.

9 In this context the useful life of an asset is the point up to which it can safely continue to be used to deliver the outputs expected of the asset. In some cases the useful life of an asset may be different to the regulatory depreciation period for the asset.

4. Efficiency and innovation is rewarded

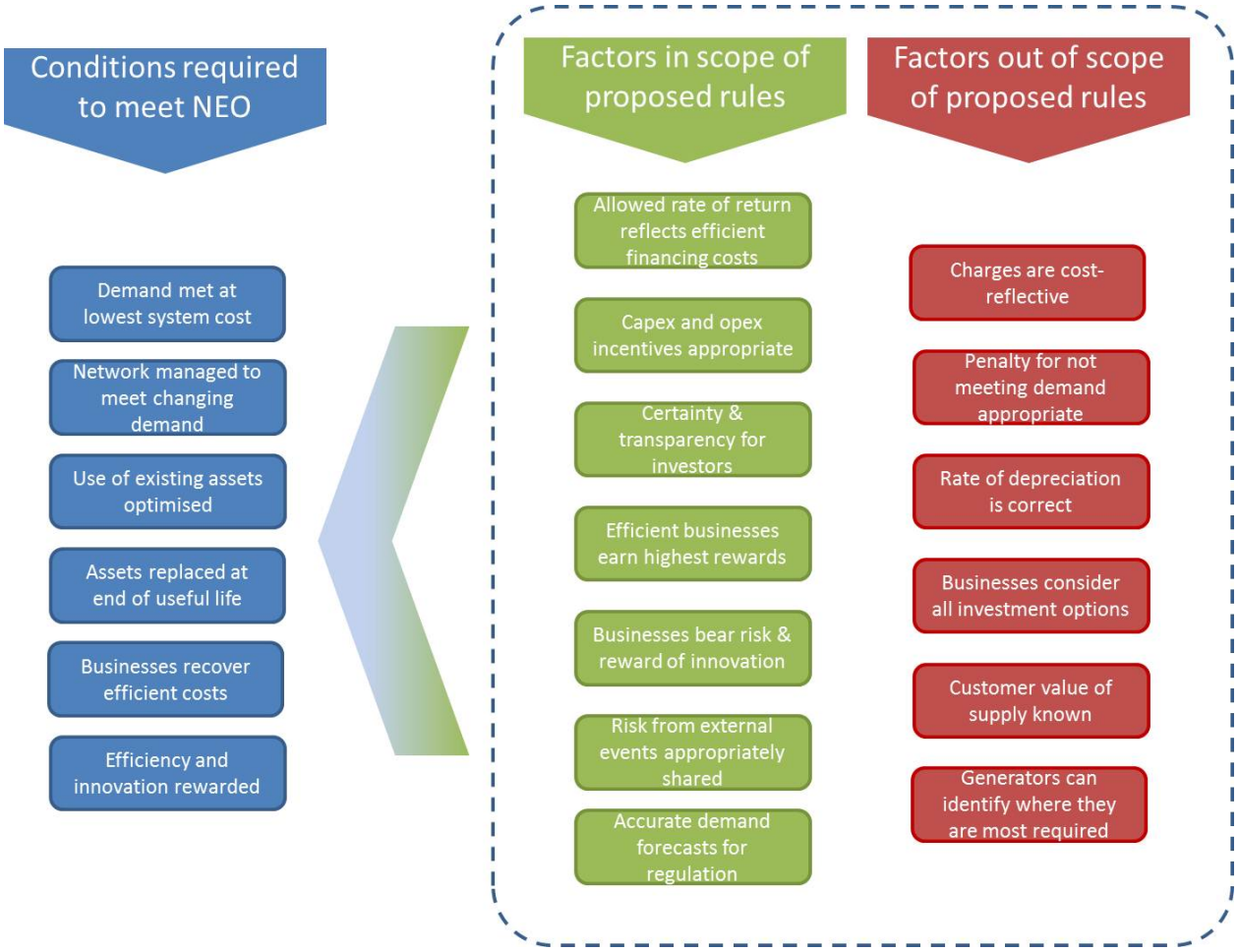
Each element of the proposed rules could impact on one or more of these conditions, and analysis of the rule change requests will involve assessing the magnitude of that impact, and therefore the extent to which it contributes to meeting safety and reliability standards at least cost.

The issues raised in the rule change requests all fall within the current methodology for the economic regulation of network services, ie the building blocks approach. Accordingly, the Commission is neither reviewing the fundamental approach to network regulation nor every aspect of the current approach as part of its assessment of these rule change requests. The extent to which the above conditions are met will depend on the combination of a large number of factors within the regulatory framework, the business environment and the external environment. It is important to be clear that the rule change requests can only impact a relatively small number of those factors.

Appendix B describes how the achievement of each of the above conditions would promote the NGO and NEO, by explaining how it would contribute to meeting reliability and safety standards at efficient long term cost. It explains in more detail how the conditions contribute to the NGO or NEO, and how the regulatory framework, market conditions, business specific factors such as governance and externalities such as government policy and natural disasters affect those conditions. When assessing the rule change requests against the NEO or NGO, the Commission is looking at whether the rule will deliver better outcomes than the current arrangements.

Figure 2.1 summarises the factors which can impact on achievement of the NEO and NGO, and shows those which may potentially be affected by the rule change requests.

**Figure 2.1 Factors affecting NGO and/or NEO**

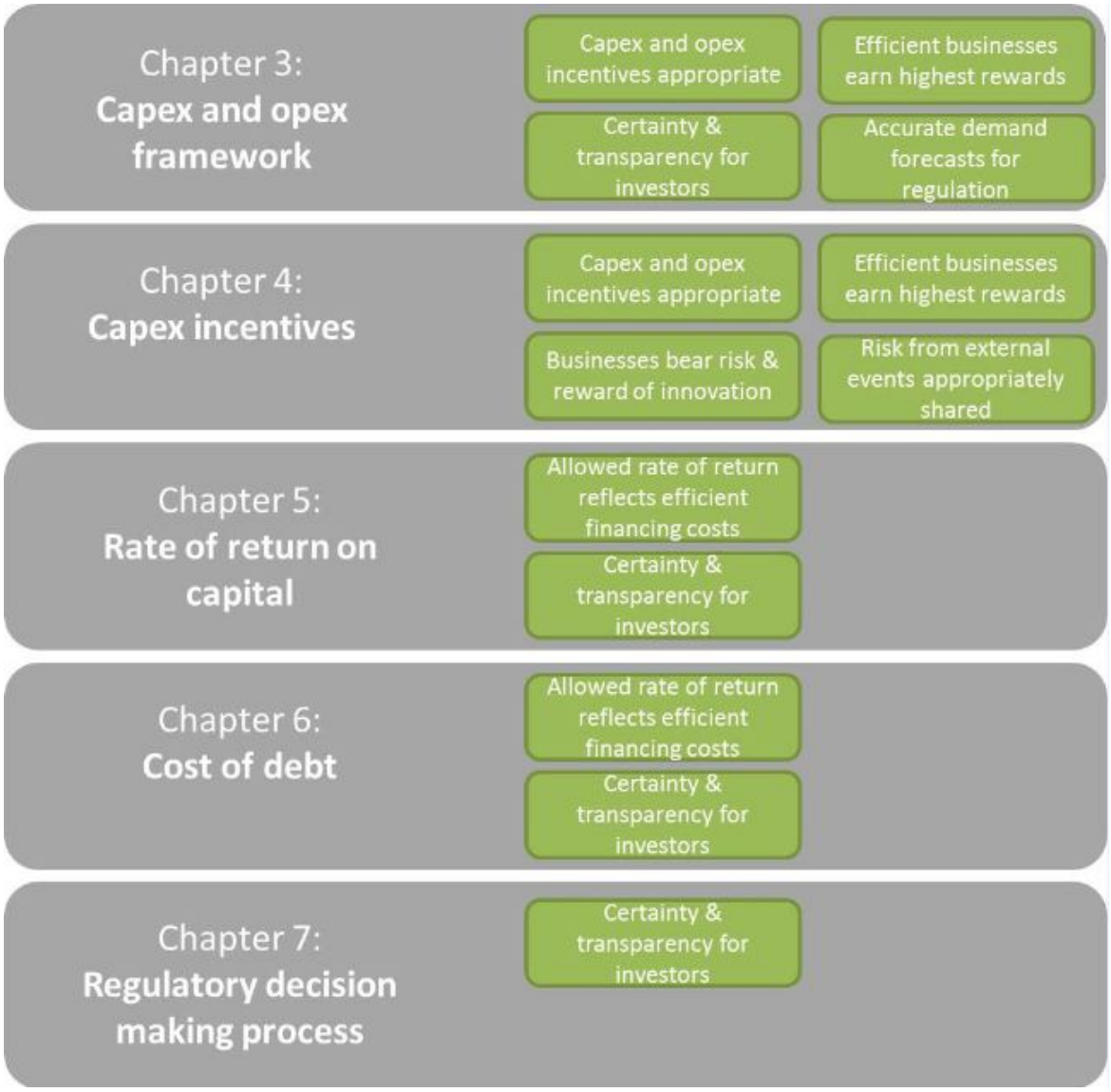



The following chapters assess how the various aspects of the rule change requests have the potential to impact one or more of the relevant factors. Figure 2.2 summarises which factors may be relevant to which aspect of the requests. As summarised in Chapter 1, the only proposed changes to the *gas* rules in the rule change requests relate to the determination of the rate of return on capital (including the cost of debt). Chapters 5 and 6 therefore relate to both gas and electricity; the other chapters relate only to electricity.

The AEMC welcomes submissions on the proposed approach to assessing the rule change proposals set out in this chapter and Appendix B. The AEMC will finalise and confirm its assessment framework when it makes the draft rule determination.

| | |
|---|---|
| **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?** |

**Figure 2.2 Factors affecting NGO and/or NEO by chapter**




### 2.3.1 Other factors that affect outcomes for consumers

The level of efficiency is measured by the amount of resources required to achieve a certain output. Where the resources or costs involved in the process of regulating service providers can be reduced without affecting the outcome (eg through administrative savings), this will represent a clear (but probably small) improvement in efficiency in the long term interests of consumers. The impact will only be unambiguous where there are clearly no other impacts on the achievement of the NEO/NGO.

As noted above, in addition to the provisions of the NER and NGR, there are many other factors that will affect the achievement of the NEO and NGO. Some of these factors are discussed in Chapter 8, such as the merits review process. Many of these factors are outside the Commission's broader remit, but nevertheless the Commission considers that it is very important that those organisations responsible for these wider factors ensure that these issues are effectively addressed on a continuing basis.

In this context, and in addition to the discussion in Chapter 8, it is important to recognise that the performance of a service provider depends not just on the incentives provided by the regulatory framework, but also the incentives placed by its shareholder(s) on the management of the business. If there is a significant mis-alignment between the regulatory incentives and the incentives placed on the management then this will reduce the quality of the outcomes. Therefore, effective shareholder oversight of network businesses is very important to deliver good outcomes for consumers.

## 2.4 The roles of the AEMC and the AER

A number of submissions received during the first round of consultation raised the general issue of the appropriate split between the Commission's role as rule maker for the NER and NGR and the role of the AER as the body that implements the rules on network regulation. Many of these comments, particularly from service providers, urge the Commission not to effectively delegate its role to the AER by failing to provide sufficient clarity and detail within the rules regarding how the AER should carry out its role.

The energy market governance structure, set out in the Australian Energy Market Agreement and implemented through the NEL and the NGL, establishes clearly distinct roles for the AEMC and the AER.

These roles do not, however, enable a clear and unambiguous approach to the content of rules for the economic regulation of network services and how those rules should be developed. Previously this has been considered in the context of whether an obligation or power more appropriately sits within the rules or is left to the discretion of the regulator, with the rules guiding the exercise of that discretion and, in some cases, requiring the regulator to set out its approach in procedures, guidelines or other instruments. In particular the issue has been considered by the AEMC and the Expert Panel. While these previous discussions must be viewed in their context, they are nevertheless useful in informing the current assessment approach.

When reviewing the economic regulation of electricity transmission services in 2006, the AEMC separately considered the appropriate balance between codification of the framework in the rules and the conferral of discretions on the AER in different contexts. At the time the AEMC concluded that there was no general principle that could be applied to determine the appropriate extent of codification of rules in all circumstances. The AEMC's general approach was to codify those elements of regulatory methodology and process which were comparatively uncontroversial, unlikely to need to vary in application across different transmission service providers in different circumstances or which are necessary to be determined on an ex ante basis for efficient administration of the regulatory process.

The AEMC also stated that there are significant areas of regulatory decision making that should involve the exercise of judgment and discretion by the regulator. This is because good economic regulation should be sufficiently flexible to adapt to the individual circumstances of regulated businesses across different periods of time.

Areas of flexibility and discretion also allow the regulatory process to evolve with experience, learning and innovation. Importantly, however, where legal rules confer discretions on regulators the rules should also specify criteria for exercising those discretions.[10]

This approach was similar to that taken by the Expert Panel. The Expert Panel referred to other circumstances where rules might be the appropriate instrument such as where the provision would have a significant impact on the economic efficiency of the market and market design; and where the provision would have effects that are likely to change relatively infrequently over time.

The Expert Panel also noted that the level of discretion given to the regulator through the rules raises a number of conflicting objectives, particularly from the viewpoint of regulated entities. Prescription in the rules promotes certainty and stability of regulatory outcomes. It also assists in promoting a transparent commercial and policy assessment of the regulatory approach. Conversely, a high level of prescription reduces the regulator's ability to accommodate the particular circumstances of individual market participants in regulatory decisions. The Expert Panel concluded that the balance between these conflicting objectives will vary depending on the matter at issue, as will the interests of different stakeholders.[11]

These approaches confirm that, in the present context, the Commission must consider on a case by case basis the best way to achieve the NEO and NGO, taking into account the RPP. From this, the Commission can determine the level of detail and clarity within the NER or NGR, as the case may be. This has been undertaken by the Commission, as well as SCER, as the Ministerial Council on Energy (MCE) as rule maker in the past. Within the current rules there are a range of different approaches, with some aspects involving quite extensive prescription, eg the timetable to be followed for a determination, while other aspects contain quite broad discretion, such as the approach the AER and the Economic Regulatory Authority (ERA) can adopt to setting the rate of return for gas service providers. Current appeal mechanisms, in the form of merits review and judicial review provide constraints on the use by the regulator of its powers under the rules. This is also a relevant factor to consider in this context.

10 AEMC 2006, *Economic regulation of transmission services*, Rule determination, 16 November 2006, pages xix - xx

11 Expert Panel on Energy Access Pricing, Report to the Ministerial Council on Energy, April 2006, p 23 - 24

# 3 Capex and opex allowances

**Summary**

- Under the NER, the AER has responsibility for approving NSPs' forecasts of capex and opex. The NER include detailed provisions about how the AER is to approve such forecasts.
- The AER is concerned the NER overly restricts its ability to interrogate and amend these forecasts, and that this means network costs are higher than efficient.
- The Commission seeks more evidence to understand the drivers for increases in network costs, and the extent to which the NER approach to capex and opex forecasts is contributing to this.
- The Commission will also confirm whether the policy settings for capex and opex allowances are consistent with the practices of other regulators in Australia and overseas.

## 3.1 Objective

This Chapter and the next address allowances for, and efficient expenditure of, capital expenditure (capex) and operating expenditure (opex) by NSPs. In respect of this expenditure the overall objective is to achieve appropriate network investment and management so that safety and reliability standards are met while consumers pay no more than necessary for the network services they receive. The expenditure should represent efficient (in the long term), adequate and timely investment in and operation of network capacity (including trading off investment in new and replacement assets, maintenance of existing assets and other options such as demand side management).[12]

A challenge in respect of Chapters 6 and 6A of the NER is to set appropriate incentives to achieve this objective.[13] This will likely involve a range of incentives, which must be correctly balanced amongst themselves (for example, between capex and opex). The NER should provide an incentive on NSPs to provide accurate forecasts (e.g. of demand) and to reveal efficient costs. It should provide incentives so that the most efficient NSPs earn the highest rewards and those that are inefficient are penalised.

The NER should also encourage innovations which improve outcomes for consumers (eg lower costs or better service) through allowing businesses to keep a share of the benefits brought about by such innovations, while also shielding consumers from the risks of innovations which do not bring about such outcomes. Similarly, the risks from events which are beyond the direct control of NSPs should be appropriately shared

12 In practice, efficiency can only be measured by comparison to other companies.

13 Chapter 6 of the NER relates to electricity distribution; Chapter 6A of the NER relates to electricity transmission.

between businesses and consumers. It should also provide stakeholders with certainty and transparency in respect of the regulator's decisions. Certainty and transparency create confidence in the regulator's decisions and allow investments to be appropriately planned.

## 3.2 Capex and opex allowances for NSPs

### 3.2.1 Context

Chapters 6 and 6A of the NER each contain a framework under which the AER, in a regulatory determination, determines capex and opex allowances for electricity distribution network service providers (DNSPs) and electricity transmission network service providers (TNSPs) respectively.[14] These allowances contribute to the overall revenue allowance for a NSP. In many respects these frameworks are the same, although there are some potentially important differences between electricity distribution and transmission. The AER is concerned that these frameworks are too prescriptive and do not allow it enough discretion to determine efficient levels of capex and opex. The AER states this lack of discretion means that it is constrained in its ability to reject inefficient capex and opex forecasts, and, in turn, results in network charges (and overall prices) which are higher than they would otherwise be. The AER has proposed changes to overcome this.

### 3.2.2 Current rules

In respect of capex, the relevant provisions are set out in clauses 6.5.7 (distribution) and 6A.6.7 (transmission) of the NER. In respect of opex, the relevant clauses are 6.5.6 (distribution) and 6A.6.6 (transmission) of the NER. Each of these clauses contains a series of objectives, criteria and factors. The objectives are the matters the capex or opex is to achieve. The criteria describe the manner in which the capex or opex is to achieve the objectives. The factors, which are discussed below in section 3.3, set out the matters to which the AER must have regard when it makes its decision on capex or opex.

The key decision-making requirement, which is very similar for Chapters 6 and 6A and for capex and opex, is that the AER must start from the NSP's regulatory proposal and must accept a capex or opex forecast if it is satisfied the total forecast reasonably reflects the relevant criteria, taking into account the relevant factors.[15] If the AER is not so satisfied, it must not accept the forecast. Where the AER does not accept a forecast (which must be in respect of the total proposed and not, for example, a particular project) it must substitute that forecast with another amount. Under Chapter 6A this other amount must be the amount the AER is reasonably satisfied reflects the criteria

14 In this Chapter 3, references to "regulatory determination" are to the distribution determination and revenue determination in each of Chapters 6 and 6A of the NER respectively.

15 See for example NER clause 6.5.7(c). In this chapter 3, 'regulatory proposal' means a proposal of the same name under chapter 6 of the NER or a revenue proposal under chapter 6A of the NER.

taking into account the relevant factors.[16] Under Chapter 6 there are two additional requirements the AER must take into account when determining a substitute amount. First, the substitute must be based on the DNSP's regulatory proposal.[17] Secondly, the substitute must be amended from the proposal only to the extent necessary to enable it to be approved under the NER.[18]

Benchmarking receives attention in both the AER's rule change request and submissions in response to it. The capex and opex factors require the AER to take into account benchmark expenditure.[19] The criteria also expressly require the AER to take into account the circumstances of the relevant NSP, which could be seen to guide the way benchmarking should be undertaken.[20]

The Chapter 6A rule determination contains useful explanatory material in respect of the decision-making requirement. The AEMC stated that it intended that the AER would not be "at large" in being able to reject a TNSP's forecast and replace it with its own, and that the AER must have regard to the information in the NSP's regulatory proposal.[21] This is an important point of policy made clear by the AEMC; the NSP's regulatory proposal is the AER's starting point and represents the most significant evidentiary consideration for the AER. The constraint on the AER's power of substitution is that the substitute meet the test of efficiency, prudency, and a realistic expectation of cost inputs.[22] At the time of making Chapter 6A, the AEMC did not think that expenditure forecasts could be specified with precision; meaning that there is no best or correct figure. At the same time though, the AEMC did not intend that the NER contemplate a range of permissible outcomes such that there could be a bias towards a higher amount.[23] The AEMC specifically avoided referring to a reasonable estimate, or imposing a legal burden of proof.[24]

The AEMC considered that the AER would use a range of techniques and inputs to test the forecasts of costs provided by NSPs:

> "While informed opinions may differ on what are efficient costs, costs of a prudent operator or realistic expectations of forecast demand and input costs in the circumstances facing the regulated entity, those matters can be tested readily by reference to objective evidence drawn from history, the performance and experience of comparable businesses and the assessments of electricity industry experts.[25]"

16 See for example NER clause 6A.13.2(b)(3).

17 NER clause 6.12.3(f)(1).

18 NER clause 6.12.3(f)(2).

19 See for example NER clause 6A.6.7(e)(4).

20 See for example NER clause 6A.6.6(c)(2).

21 AEMC, *Economic Regulation of Transmission Services*, Rule Determination, 16 November 2006, p. 53.

22 Ibid.

23 Id., p. 52.

24 Ibid.

25 Id., p. 53.

### 3.2.3 AER proposal

By way of background, the AER observes that real electricity prices have been increasing rapidly since 2007 in most states and territories. The AER recognises that a significant proportion of the more recent price rises can be attributed to increases in regulated network charges. Furthermore, the AER notes the drivers for recent increases in network charges in part are the increased investment to replace ageing assets and to meet increases in peak demand, growing customer connections and higher reliability standards.[26] However, the AER attributes part of the price rises to limitations on its ability to regulate NSPs effectively, and thus questions whether the current framework is meeting the NEO in "promoting efficient investment".

The AER notes that the expression "reasonably reflects" in the capex and opex criteria means that there is a range of forecasts that may meet the criteria.[27] If a forecast falls within this range, the AER must accept it, even if there is a lower possible forecast that would satisfy the criteria. In these circumstances, the AER states, a NSP will always forecast at the top of the range, leading to inflated forecasts.[28] To address this perceived problem, the AER proposes that the capex and opex criteria should be reworked. The AER's proposal is that the criteria should merely require the AER to determine the total of capex or opex which would represent the efficient capex or opex required by a prudent NSP to achieve the capex or opex objectives (which themselves would remain unchanged).[29] Thus, there would no longer be a reference to the NSP's regulatory proposal in the capex and opex criteria, and the AER's decision would no longer be required to approve or reject this. It would not be necessary for the AER to consider a range of acceptable forecasts.

The AER also proposes removing some of the restrictions on its ability to determine substitute forecasts. It claims that the restriction in Chapter 6 of the NER on amending a regulatory proposal "only to the extent necessary" means that there will be no possible result other than an estimate which is at the top of the range.[30] In respect of the requirement in Chapter 6 that the AER's substitute amount must be based on the NSP's regulatory proposal, the AER states this locks it into forming a substitute on the same basis as the NSP has. Since most NSP regulatory proposals use engineering detail to determine a "bottom up" calculation, this means that the AER must conduct a line by line analysis to reduce the forecast back to a reasonable range.[31] The AER would prefer to use a mix of assessment techniques, including "top down" approaches.

Finally, the AER also proposes deleting the reference in the opex and capex criteria to the circumstances of the relevant NSP. It states that good benchmarking requires the characteristics of the relevant network be taken into account, but not necessarily the

26 AER, Rule change request, Part A, 29 September 2011, p. 6.

27 AER, Rule change request, Part B, 29 September 2011, p. 27.

28 AER, Rule change request, Part B, 29 September 2011, p. 28.

29 See for example AER, Rule change request, Part C Draft Rules, 29 September 2011, p. 25.

30 AER, Rule change request, Part B, 29 September 2011, p. 29.

31 Ibid.

circumstances of the owner. According to the AER, the language currently used may limit its ability to apply benchmarking.[32]

### 3.2.4 Submissions

**Drivers for high prices**

Submissions received during the consultation process express various opinions on whether the regulatory framework is the key driver of the network price rises.

Submissions from most consumer groups and some government departments support the AER's proposal on whether the current regulatory framework is delivering a necessary and efficient level of investment.[33] They submit that the deficiencies in the design and conduct of economic regulation may account for part of the electricity price increases.[34]

However, most NSPs argue that the current regulatory framework is effective and a fundamental change is unnecessary.[35] In particular, SP Ausnet submits that analysis from Ernst and Young shows that distribution network costs in Victoria have decreased by 20 per cent in real terms between 1996 and 2010, including advanced metering infrastructure costs; and transmission network costs have increased slightly by 2 per cent in real terms during this period.[36]

NSPs suggest there are other reasons for rising network prices. For example, one submission provides that the changes in price are a reflection of the poor regulatory decisions in the past which produced artificially low prices compared to costs.[37] NSPs also submit that it is the investment required to meet the need for replacement of ageing assets, spatial peak demand and higher reliability standards that has resulted in higher network charges.[38] NSPs also argue that higher network costs are not any proof of failure of the regulatory regime or the regulatory bodies which currently apply them.[39]

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32 AER, Rule change request, Part B, 29 September 2011, p. 33.

33 Australian Industry Group, Consultation Paper submission, 13 December 2011, p. 1; IPART, Consultation Paper submission, 8 December 2011, p. 5; QMAG, Consultation Paper submission, 8 December 2011, p. 2; TasCOSS, Consultation Paper submission, 8 December 2011, p. 2.

34 Amcor, Consultation Paper submission, p. 1; EUAA, Consultation Paper submission, 8 December 2011, p. 1; Financial Investor Group, Consultation Paper submission, 8 December 2011, p. 7; NSW Business Chamber, Consultation Paper submission, 8 December 2011, p. 1.

35 Aurora Energy, Consultation Paper submission, 15 December 2011, p. 16; Ausgrid, Consultation Paper submission, 8 December 2011, p. 2; Endeavour Energy, Consultation Paper submission, 8 December 2011, p. 2; Essential Energy, Consultation Paper submission, 14 December 2011, p. 4; Grid Australia, Consultation Paper submission, 8 December 2011, p. 2.

36 SP AusNet, Consultation Paper submission, Ernst & Young Report, 8 December 2011, p. 14.

37 Ausgrid, Consultation Paper submission, 8 December 2011, p. 2.

38 ESAA, Consultation Paper submission, 15 December 2011, p. 3.

39 ENA, Consultation Paper submission, 8 December 2011, p. 6; Endeavour Energy, Consultation Paper submission, 8 December 2011, p. 2.

NSPs point out that other factors may also lead to increases in energy prices. These factors include global economic instability, introduction of renewable energy schemes, and new taxes and charges.[40]

The Energy Users Association of Australia (EUAA), a large consumer group, argues that the NSPs have failed to show a link between, on the one hand, rising demand, ageing assets and historic under-investment, and on the other hand, higher network charges.[41] The EURCC points out that commissioned studies by the NSW Government and the Energy Supply Association of Australia (ESAA) during the mid 1990s show that there is historic over-investment not under-investment by NSW distributors.[42] The EURCC and EUAA submit that ownership, the conduct of regulation and the design of regulation are the three possible factors affecting the observed price increases, as identified in reports by Mountain and Littlechild (2010) and Mountain (2011).[43]

**Operation of the existing framework**

NSPs state that the NER, in respect of capex and opex allowances, are currently working well, and that the mere fact of increasing expenditure allowances does not of itself show that there is a problem with the NER.[44] Submissions have argued that in circumstances where there is not yet information available for one full regulatory control period it is premature to revisit the NER.[45]

Most NSPs strongly suggest that there is no evidence from the AER's regulatory determinations that it has been constrained in the way it has suggested. For example, Ausgrid states there is no evidence the AER starts from a range and its substitute forecasts are forced into the top of the range.[46] Other NSPs state that the AER is not confined to bottom up analysis, and does apply top down checks.[47] The fact that the AER applies the same approach in Chapter 6A, where there are not the same constraints as in Chapter 6, in the opinion of some NSPs, shows that the problem is not the NER itself but the way the AER applies the NER.[48] In any event, it is appropriate that the AER should always start its assessment with the NSP's regulatory proposal,

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40 ENA, Consultation Paper submission, 8 December 2011, p. 7; Essential Energy, Consultation Paper submission, 14 December 2011, p. 4.

41 EUAA, Consultation Paper submission, 8 December 2011, p. i.

42 EURCC, Consultation Paper submission, CME Report, 15 December 2011, p. 6.

43 EUAA, Consultation Paper submission, 8 December 2011, p. i; EURCC, Consultation Paper submission, CME Report, 15 December 2011, p. 11.

44 Endeavour Energy, Consultation Paper submission, 8 December 2011, p. 2; ENA, Consultation Paper submission, 8 December 2011, p. 26; Ergon Energy, Consultation Paper submission, 8 December 2011, p. 6.

45 See for example ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 47.

46 Ausgrid, Consultation Paper submission, 8 December 2011, p. 12.

47 Aurora Energy, Consultation Paper submission, 15 December 2011, p. 6; Jemena, Consultation Paper submission, 8 December 2011, p. 31.

48 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 50.

and that it undertake a line by line assessment of that proposal, though this should not exclude other analytical tools.[49]The NSPs submit that there is sufficient protection in place to stop NSPs submitting inflated forecasts.[50]

NSPs also state that it is essential that the AER be required consider the individual circumstances of each NSP when benchmarking.[51]

Consumer groups, in general, support the AER's proposals in this area. Many groups say that more flexibility for the AER is needed, and identify as a key concern the requirement that the AER only adjust allowances on the basis of the regulatory proposal. This limits sources of information and methods of analysis. [52]Total Environment Centre (TEC) states that the NER do not give the AER enough power to curb excessive regulatory proposals, and tie the AER too much to the regulatory proposal.[53] There is also some concern that there is an onus on the AER to prove forecasts do not reflect efficient costs, and that this should be reversed.[54] There is also support for removing the reference to the circumstances of the NSP.[55]

Amongst other stakeholders there is general support for the AER's proposal. Retailers view the changes as allowing the AER to use a variety of approaches in estimating efficient costs, which will reduce the chance of revenues being systematically inflated.[56] The Victorian Department of Primary Industries (Victorian DPI) also supports the AER having more power to use a range of regulatory tools to assess capex, which would reduce the emphasis on line by line assessment.[57] The Independent Pricing and Regulatory Tribunal (IPART) supports in particular the removal of the "reasonably reflects" test, which it states makes it difficult for the AER to provide a balanced determination, since it must approve a forecast at the upper end of the reasonable range.[58] By contrast, the South Australian Department for Manufacturing, Innovation, Trade, Resources and Energy (SA DMITRE) does not support the removal of the "reasonably reflects" test, which it says would not reflect a

49 ENA, Consultation Paper submission, 8 December 2011, p. 27; Jemena, Consultation Paper submission, 8 December 2011, p. 25.

50 UE and MG, Consultation Paper submission, 8 December 2011, p. 8; Essential Energy, Consultation Paper submission, 14 December 2011, p. 5.

51 Ausgrid, Consultation Paper submission, 8 December 2011, p. 14; Ergon Energy, Consultation Paper submission, 8 December 2011, p. 13.

52 EUAA, Consultation Paper submission, 8 December 2011, p. 20; EURCC, Consultation Paper submission, 15 December 2011, p. 14; MEU, Consultation Paper submission, 8 December 2011, p. 18.

53 TEC, Consultation Paper submission, 8 December 2011, p. 2.

54 Consumer Action Law Centre, Consultation Paper submission, 9 December 2011, p. 3.

55 Australian Paper, Consultation Paper submission, 8 December 2011, p. 20.

56 ERAA, Consultation Paper submission, 8 December 2011, p. 1.

57 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 3.

58 IPART, Consultation Paper submission, 8 December 2011, p. 9.

balanced position since the AER should be required to consider the regulatory proposal submitted by the NSP.[59]

### 3.2.5 Analysis

The consultation paper published on 20 October 2011 in respect of the rule change request identified four "themes" for consultation, the first being whether there is a problem present as identified by the AER.[60]

The Commission's preliminary analysis of the problem in respect of capex and opex allowances has been separated below into four components: what the AER's regulatory determinations show; what the Tribunal has said; whether there is any useful data; and analysis by the AEMC's consultants.

A key issue for this Chapter, and indeed for the directions paper in general, is whether, and if so to what extent, the NER contribute to network charges that are higher than necessary to meet the relevant objectives. This provides evidence of how the NER are working in practice, which is important to supplement the consideration of how the NER work in theory. The Commission considers that the level of analysis provided by stakeholders of the drivers for network cost increases to date has been limited and there may be scope for further analysis to inform the Commission's assessment. A discussion of some of the further analysis which could be provided is set out below.

The Commission also observes that the price and service outcomes experienced by consumers are a function of three drivers:

- the legal and regulatory framework;
- the application of that framework by the regulator; and
- the corporate governance of NSPs and gas service providers.

The efficiency of NSPs and gas service providers in large part depends on the way in which the drivers work together. This leads to two conclusions. First, regulation cannot compensate for weaknesses in corporate governance arrangements. Secondly, to the extent that network outcomes are considered to be inappropriate, it is necessary to understand the degree to which these outcomes are a product of the rules, as opposed to other drivers. This is particularly relevant in assessing these rule change requests.

Finally, while there has been much discussion in the rule change request and submissions about high prices, it is also important to note that if prices are lower than what is required to meet the relevant objectives, and in particular the reliability standards, this can itself have adverse long term consequences for consumers.

59 SA DMITRE, Consultation Paper submission, 23 December 2011, p. 3.

60 AEMC, AER Network Regulation Rule Change, Consultation Paper, 20 October 2011, p. 5.

**AER regulatory determinations**

The Commission has reviewed many of the AER's regulatory determinations as part of its initial assessment of the AER's concerns regarding capex and opex allowances under the NER.

On the basis of this review, the AER's reasons in its determinations of NSP capex and opex allowances do not appear to demonstrate convincingly that it has been constrained by the NER in the way that it claims in its rule change request. While there may be a problem, the AER's regulatory determinations do not indicate what that problem is, or that it would have done anything differently under the rules it has proposed. While the Commission accepts that the AER would not have undertaken additional analysis beyond that which the AER considered necessary to meet the NER, it might have been expected that the determinations (or some other work undertaken internally by the AER) would have given some indication of how the AER's concerns about its powers under the NER had constrained the analysis it could undertake.

In AER regulatory determinations, there is almost no reference to the AER starting its assessment of a capex or opex forecast by considering what a reasonable range might be for the capex or opex. This might be suggested by the "reasonably reflects" concept and the requirement that a substitute be amended from the regulatory proposal only to the extent necessary to be approved. References can be found in AER regulatory determinations to changes being made only to the extent necessary to meet the NER, but it is unclear what the effect of this is in the absence of other references to a range. Indeed, the AER itself notes that it generally does not approach assessment of a capex or opex forecast by adopting a maximum possible number and a minimum possible number.[61] The Energy Networks Association (ENA) also notes this point.[62] Conversely, there is evidence of the AER having used a mid-point between its consultant's analysis and the relevant estimate provided by DNSPs.[63]

In respect of DNSPs, the AER claims that the requirement that a substitute forecast is based on the regulatory proposal locks it into a line-by-line approach to assessing forecasts.[64] In fact, it is possible to find evidence of the AER applying its own analytical techniques to capex and opex proposals. A good example of this is the "repex" model that has been applied by the AER recently to determine replacement capex. This uses age as a proxy for the range of factors that are drivers for individual asset replacements.[65] It also reflects historical levels and costs. This has been applied

61 AER, Response to AEMC questions on rule change proposals, 2 February 2012, p. 10.

62 ENA, Consultation Paper submission, Attachment C, 8 December 2011, p. 24.

63 AER, *Final Decision - NSW distribution determination 2009-2010 to 2013-2014*, 28 April 2009, p. 172.

64 AER, Rule change request, Part B, 29 September 2011, p. 26.

65 AER, Victorian draft distribution determination 2011-2015, June 2010, p 339.

in the AER's final regulatory determination for the Victorian DNSPs and also in the recent Aurora Energy draft regulatory determination.[66]

In respect of benchmarking, the AER suggests that the NER may limit its ability to apply comparative analysis and benchmarking.[67] No evidence has been presented of decisions where the references to "individual circumstances" in the opex or capex criteria limited the AER's ability to apply benchmarking. The AER has certainly applied benchmarking frequently in its regulatory determinations (as appears to be intended by the capex and opex factors).[68] For example, in the recent draft regulatory determination for Aurora Energy, the AER commented that it had undertaken:

> "... benchmarking analysis for total capex and specific components of capex as well as for unit costs.[69]"

Other examples can be found in the AER's final regulatory determinations for Ergon Energy, EnergyAustralia and the Victorian DNSPs.[70] This frequent use of benchmarking, which is a top down form of assessment, also supports the claim by NSPs referred to above that the AER has not demonstrated that it has been locked into a bottom up approach to assessment.

The AER has stated that it is inevitable that a portion of costs escape regulatory scrutiny.[71] In practice the AER has from time to time used a sampling approach, where it reviews a portion of projects proposed by the NSP and then, based on a reduction for that sample of projects, makes a proportionate reduction to projects it has not reviewed in detail. For example, in the regulatory determination for ETSA Utilities, the following comment was made:[72]

> "The AER considers that given the level of adjustment required to the categories subject to the detailed review, a general adjustment to the remaining replacement capex is, under the circumstances, justified.[73]"

This suggests the AER has found ways of applying specific analysis more broadly to cover all costs. If there is insufficient time for the AER to consider all of the elements of

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66 AER, *Final Decision - Victorian electricity network service providers Distribution Determination 2011-2015*, October 2010, p 426; AER, *Draft Distribution Determination - Aurora Energy 2012-13 to 2016-17*, November 2011, p. 113.

67 AER, Rule change request, Part B, 29 September 2011, p. 33.

68 See for example NER clause 6.5.6(e)(4).

69 AER, *Draft Distribution Determination - Aurora Energy 2012-13 to 2016-17*, November 2011, p 117.

70 AER, *Final Decision - Queensland Distribution Determination 2010-11 to 2014-15*, May 2010, p. 421; AER, Final Decision - NSW distribution determination 2009-2010 to 2013-2014, 28 April 2009, p. 174; AER, *Final Decision - Victorian electricity network service providers Distribution Determination 2011-2015*, October 2010, p. 400.

71 AER, Rule change request, Part B, 29 September 2011, p. 30.

72 AER, South Australian draft distribution determination 2010-11 to 2014-15, May 2010, p.146.

73 AER, *Draft Decision - South Australia Draft Distribution Determination 2010-11 to 2014-15*, May 2010, p.146.

a regulatory proposal then this may be best addressed by considering the appropriateness of the overall timetable for the regulatory determination process.

**Tribunal comments**

The Australian Competition Tribunal (Tribunal) has had a number of opportunities to consider the provisions in the NER relating to capex and opex forecasts. A review of the Tribunal's decisions in respect of electricity matters since 2008 reveals several things.

First, the Tribunal takes a relatively expansive view of clause 6.12.3. In the matter of *Application by EnergyAustralia and Others* it states the following:

> "The primary discretion given to the AER by cl 6.12.3(a) is to refuse to accept or approve any element of a regulatory proposal. The AER's power to substitute an amount or value or methodology exists so that it may properly perform its obligation under cl 6.12.1(4)(ii) to set an estimate of the total opex that the AER is satisfied reasonably reflects the opex criteria.[74]"

This suggests that the Tribunal's view is that NER clause 6.12.3 is a clarification of, rather than a limitation on, the requirement that it estimate the required opex or capex by reference to what is required to reasonably reflect the opex or capex criteria.

Secondly, the Tribunal has on a number of occasions taken a different view to the AER and varied an AER decision. There is no indication, however, that the Tribunal has ever formed a view that the AER has exceeded or come close to exceeding the limits of the discretion it has in respect of capex and opex allowances.

**Analysis of Data**

As set out above, some NSPs have cautioned against revisiting the basis for capex and opex allowances until a full dataset - representing at least one regulatory control period - is available to show how actual expenditure compares to allowances. [75] By contrast, Professor Littlechild takes the view that since the AER's concerns relate to the allowances themselves, and these have already been set for the current regulatory control periods, evaluation of those concerns with the NER may begin.[76] This latter view implies that data on actual expenditure is not needed to commence an analysis of the NER. The Commission takes the initial view that there is some analysis that may usefully be undertaken, as described below.

An additional concern with data on capex and opex allowances, and in particular a historical comparative analysis involving such data, is that there are many factors other than the NER that can influence the need for capex and opex. For example, the AER presents data of how forecast capex and opex for the current period compare to actual

74 [2009] ACompT8 (12 November 2009) [255].

75 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 47; Financial Investor Group, Consultation Paper submission, 8 December 2011, p. 20.

76 Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, p. 13.

capex and opex for the previous period.[77] The AER suggests that while there are legitimate reasons for some increases, the sharp step change draws into question whether the current framework meets the NEO.[78]

However a number of stakeholders have described the other factors causing increasing costs. The ESAA takes the view that increasing network charges are primarily driven by ageing assets, peak demand, and quality changes (in the form of undergrounding and reliability standards).[79] The ENA would add the connection of remote renewable energy sources and rising input costs to the list of factors requiring greater capex and opex.[80]

The EURCC has attempted to rebut the claims that expenditure outcomes are attributable to rising demand, ageing assets and historic underinvestment.[81] These arguments, which focus in particular on the differences between privately-owned and publicly-owned DNSPs, have some merit but do not conclusively rule out these factors. The Commission observes that there is in general a lack of evidence presented to support claims of a causal link between deficiencies in the NER and rising network costs. At the same time, those (such as NSPs) who claim network costs are in fact due to other factors are invited to make further submissions to describe in better detail what these factors are and, from a quantitative perspective, how they contribute to rising network costs. The Commission's preliminary view is that rising levels of capex and opex are not enough on their own to show a deficiency in the NER.

A more sophisticated analysis than just looking at capex and opex costs would incorporate measures of efficiency, and perhaps compare the effect of rising levels of opex or capex on a NSP's efficiency. The efficiency of a NSP is, however, a particularly difficult parameter to determine, and it can only realistically be measured in a comparative sense.

The EURCC submission refers to a report by Bruce Mountain in 2011 which offered a possible method for establishing the efficiency of DNSPs.[82]This approach regressed total annual expenditure against a composite scale variable consisting of line length and number of customers. Results were presented by plotting all DNSPs on a graph of decrease in efficiency over three periods against relative efficiency in the third period. On the basis of this analysis, the average privately owned DNSP is shown to be more efficient than the average government-owned DNSP. While there are many other factors that might arguably affect the relative efficiency of different DNSPs, such as differences in labour costs, the Commission is not aware of any subsequent, more sophisticated analysis which has rebutted the broad conclusions reached by Bruce

77 AER, Rule change request, Part A, 29 September 2011, p. 7.

78 Id., p. 8.

79 ESAA, Consultation Paper submission, 15 December 2011, p. 3.

80 ENA, Consultation Paper submission, 8 December 2011, p. 7.

81 EURCC, Consultation Paper submission, 15 December 2011, p. 5.

82 B. R. Mountain, "Australia's rising electricity prices and declining productivity: the contribution of its electricity distributors.", Energy Users Association of Australia, Melbourne, May 2011, cited in EURCC, Consultation Paper submission, 15 December 2011, p. 6.

Mountain. Professor Littlechild has also expressed surprise that more sophisticated analysis has not been presented.[83] Other measures of efficiency presented in submissions include operating costs per customer, minutes of outage per customer and outages compared against replacement capex.[84]

Finally, evidence has been presented in submissions of previous percentage reductions between the capex and opex forecasts in NSPs' initial regulatory proposals and AER final regulatory determinations. For example, ENA has presented summaries of the level of these cuts.[85] This demonstrates that the AER is able to make reductions, but provides little detail of what these are.

More useful is a comparison of the average reductions by the AER under the present framework compared to those under the previous regulatory framework, as presented by Grid Australia, the ENA and the Financial Investor Group.[86] It is difficult to compare the figures produced (for example the Financial Investor Group suggest jurisdictional regulators reduced capex forecasts by 10 per cent and the AER by 11 per cent, whereas the ENA suggests the median reduction by jurisdictional regulators for capex forecasts is 15.6 per cent and by the AER is 10.3 per cent). Based on what has been provided to the AEMC thus far, however, the results suggest that the AER has the power to reduce expenditure forecasts by at least an equivalent level as the jurisdictional regulators, where it determines to exercise its discretion to do so.

This directions paper sets out the Commission's preliminary views. The Commission will review any further evidence on these issues provided by stakeholders in response to this directions paper, and then consider whether it can undertake further analysis of these issues. However, the Commission would note that most of the information that would be required for such an analysis is likely to be held by the AER or NSPs, and therefore in the first instance the Commission would encourage those stakeholders to provide as much analysis as possible.

**Consultants' views**

Professor Yarrow concurs with the view that the AER has not provided enough evidence of the problem in this area that it has raised.[87]Professor Yarrow refers to the need for technical analysis on how the NER has had an upward effect on prices to support the AER's view.[88] This evidence might resemble work undertaken by Bruce Mountain and cited by the EURCC. He goes on to suggest that, given that "regulatory

83 Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, p. 2.

84 Financial Investor Group, Consultation Paper submission, 8 December 2011, p. 23; SP AusNet, Consultation Paper submission, 8 December 2011, p. 7; Endeavour Energy, Consultation Paper submission, 8 December 2011, p. 3.

85 ENA, Consultation Paper submission, Attachment C, 8 December 2011, p. 20.

86 Grid Australia, Consultation Paper submission, 8 December 2011, p. 27; ENA, Consultation Paper submission, 8 December 2011, p. 18; Financial Investor Group, Consultation Paper submission, 8 December 2011, p. 55.

87 George Yarrow, Preliminary Views for the AEMC, 12 February 2012, p. 9.

88 Ibid.

discretion comes with biases of its own", the AER should also demonstrate how, if it were given greater discretion, its proposals on capex and opex allowances would lead to better outcomes.[89] In general, he does not see prescription as a bad thing per se, and he observes a small step in Great Britain towards the more prescriptive approach of the NER.[90]

Professor Littlechild recognises the powerful case made by the NSPs that the AER has not been constrained in practice, but also observes the AER may be constrained by the NER more than other regulators are constrained.[91] He notes that NSPs do not fully address the AER's concerns as to the possibility that investment has been excessive and at too high a cost to consumers.[92] Professor Littlechild also observes that some relaxation of the NER would be conducive to better achieving the NEO.[93]

On benchmarking, Professors Yarrow and Littlechild have similar views that a regulator should take into account the actual circumstances of the NSP when it benchmarks. Professor Littlechild suggests that the AER be invited to clarify in which circumstances it would or would not be appropriate to take into account and to explain the implications of this.[94]

Finally, both Professors Yarrow and Littlechild see benefits in outcomes that are arrived at by a process of agreement between the relevant parties, rather than having to be mandated (such as by a regulator).[95]

**Other comments**

In the AER's rule change request reference is made to the approach the Office of Gas and Electricity Markets (Ofgem) in Great Britain takes to setting price controls for network companies.[96] In particular, it is suggested that as compared to the AER, Ofgem has much broader discretion. The AEMC's understanding, informed by its consultants, is that while Ofgem does appear to have much broader discretion than the AER, in practice the use of this discretion is heavily constrained by the ability of the NSPs to reject price control proposals and initiate a wide ranging appeal process (though this has not stopped Ofgem from introducing a wide variety of innovative components of the price controls by mutual agreement).[97]

89 Id., p. 10.

90 Id., p. 12.

91 Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, p. 3.

92 Id., p. 2.

93 Id., p. 3.

94 George Yarrow, Preliminary Views for the AEMC, 12 February 2012, p. 17; Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, p. 16.

95 George Yarrow, Preliminary Views for the AEMC, 12 February 2012, p. 19; Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, pp. 6, 11, 12.

96 AER, Rule change request, Part B, 29 September 2011, p. 15.

97 Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, pp. 7, 9.

Furthermore, while Ofgem may face few specific constraints on the process it can follow, in practice it assesses in detail NSPs' proposals, engages extensively at a technical level with the NSPs, but makes extensive use of benchmarking and other analytical techniques to test the NSPs' proposals. It appears to the Commission that there may not in fact be such a significant difference between the policy intent of the AEMC in developing the Chapter 6A rules for transmission and the actual practice of Ofgem.

### 3.2.6 Initial position

The Commission will undertake two streams of analysis to determine whether there is a problem with the capex and opex allowances framework and, if so, whether any changes to the NER are required. These are:

- confirm that the policy intent established as part of the Chapter 6A rule determination is still an expression of good regulatory practice; and
- analyse any further evidence provided by stakeholders in response to this directions paper on the drivers of increases in network costs and the relationship between the framework for capex and opex allowances and increases in network charges.

**Policy intent of Chapter 6A rule determination**

The AER's view is that under the NER its ability to apply other techniques is limited and that it has less discretion than other regulators.

By contrast the Commission's view is that the policy intent, as set out in the Chapter 6A rule determination and described in section 3.2.2 above, appears to remain appropriate and applicable. To advance this, between now and the publication of the draft rule determination the AEMC will undertake further work to compare the policy intent in the Chapter 6A rule determination with the actual practice of other relevant regulators, including both jurisdictional regulators in Australia and overseas regulators. This is to verify that the Chapter 6A policy intent remains appropriate.[98]The outcomes of this review will be considered in light of key features of the regulatory framework such as the governance structure established under the NEL/NGL and merits review. The Commission is interested in whether there are features of other regulators that might be taken into account when undertaking this review.

If the Chapter 6A policy intent is appropriate then the Commission will review the NER to ensure that they give effect to that intent, including to avoid ambiguities on matters such as the use of benchmarking. This will involve considering the AER's powers in the context of the overall regulatory determination process. For example, the Chapter 6A rule determination indicates that the restrictions on an AER substitute

98 It is noted that two prominent overseas regulators, being Ofgem in Great Britain and the Commerce Commission in New Zealand, have since 2006 completed significant reviews of their regulatory frameworks, which might have altered the understanding of what is best practice.

should reflect the primary decision-making rule: the criteria are efficiency, prudency and a realistic expectation of, among other things, cost inputs.[99] Applying this policy intent to Chapter 6 of the NER would suggest that the further constraints in clause 6.12.3(f), which limit AER substitutes to those "only to the extent necessary" and "on the basis of" the original forecast, are superfluous. This is particularly the case where, as NSPs claim, the constraints are not operating in practice. If the constraint is not operating, as Professor Littlechild states, there is "no obvious loss in relaxing it".[100]

A similar approach could be adopted in respect of benchmarking. The Commission takes the initial view that it accepts the submissions of the NSPs, and the comments of Professors Yarrow and Littlechild, that it would be inappropriate if benchmarking did not take into account any circumstances of the NSP (such as the different requirements for urban and rural DNSPs). At the same time, though, there are likely to be some circumstances of NSPs which it would be inappropriate to consider in benchmarking, such as financial decisions of the owner of the NSP. The Commission seeks to explore further the circumstances that benchmarking should take into account to determine whether it would be appropriate for the NER to be clarified to provide guidance on this. This approach appears to be supported by Grid Australia.[101]

**Analysing evidence of increasing network costs**

The analysis of the data and submissions described above do not support the AER's claim that it has been limited in its assessment of capex and opex proposals under the NER. The Commission welcomes further submissions, in the form of evidence, that might support or refute this initial position, including any suggestions on how more evidence on the link between the NER and price outcomes might be gathered. This evidence or analysis could be:

- quantitative, such as an estimation of how much different factors contribute to increasing network costs; or
- qualitative, such as specific case studies or examples of how the NER have limited the AER's assessment of capex and opex proposals.

Any evidence provided in this context would also be useful to illustrate particular problems with the NER and would assist in identifying drafting improvements in this regard.

**Other issues**

Professor Littlechild's paper refers to incentive schemes that would reward companies for providing information and making forecasts that turn out to be correct.[102] If such schemes could encourage more accurate forecasting, they may go some way to mitigating the deficiencies the AER claims are present in the NER. Ideally this would

99 AEMC, *Economic Regulation of Transmission Services*, Rule Determination, 16 November 2006, p. 53.

100 Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, p. 3.

101 Grid Australia, Consultation Paper submission, 8 December 2011, p. 40.

be accompanied by strong disincentives (which may include penalties) against submitting erroneous forecasts. Incentive schemes are discussed further in Chapter 4.

While the AER proposes no changes to the capex or opex objectives, it identifies a perceived problem regarding these objectives. In particular, it notes that the objectives refer to expenditure required to "maintain" quality, reliability and security of supply.[103] It observes that this may mean capex allowances could not decrease in the event jurisdictional standards were lowered since enough capex must be allowed to permit levels of reliability to be kept at existing levels. The Commission considers that a valid concern has been raised by the AER and that there is merit in exploring this issue further, particularly given the Review of Distribution Reliability Outcomes and Standards that the Commission is undertaking.

The solution may be simple, such as an amendment to the objectives to clarify that the level of capex described by the objectives should only be enough for the relevant jurisdictional reliability standard, and any other statutory standards covered by the objectives, to be met and not exceeded. The Commission invites submissions on this issue.

### 3.2.7 Issues for further comment

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| **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.** |
| **Question 3** | **Would it be appropriate for the wording of the NER to be clarified to better reflect the policy intent?** |
| **Question 4** | **What circumstances of the NSP should the AER be required to take into account when benchmarking?** |
| **Question 5** | **Would it be appropriate for the capex objectives to be clarified to better reflect jurisdictional reliability standards?** |
| **Question 6** | **What factors or features of the approaches of other regulators should be taken into account when reviewing other regimes to confirm the best practice approach to economic regulation?** |

102 Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, p. 10.

103 AER, Rule change request, Part B, 29 September 2011, p. 33.

## 3.3 Capex and opex factors

### 3.3.1 Context

The AER has proposed a number of discrete improvements to the capex and opex factors, for both electricity transmission and distribution. While the factors contribute to how the AER engages with NSPs' regulatory proposals, in most cases the changes proposed are not directly related to the general changes proposed to the provisions relating to opex and capex expenditure, which are discussed above.

### 3.3.2 Current rules

The capex factors are set out in clauses 6.5.7(e) and 6A.6.7(e) of the NER, and the opex factors at clauses 6.5.6(e) and 6A.6.6(e) of the NER. These are factors to which the AER must have regard in determining whether to approve a regulatory proposal. It is not immediately clear whether or not these are intended to be exhaustive. The factors relate to a range of different matters. Some are procedural in nature, others relate to substantive matters such as operating and capital inputs, and labour costs.

### 3.3.3 AER proposal

At a general level, the AER proposes that the capex and opex factors should be neither mandatory nor exhaustive.[104] It proposes that the requirement to consider demand forecasts and cost inputs, which it has proposed removing from the capex and opex criteria, should be included as a factor. Another proposal is that the factors relating to matters of procedure should be moved out of the factors to the areas of Chapters 6 and 6A of the NER which deal with the procedure the AER is to follow in making regulatory determinations. This would include the factor requiring the AER to consider analysis undertaken by the AER and published before the final regulatory determination. The AER has proposed amending this factor to remove the reference to publication of the analysis, on the basis that this removes an unworkable requirement to publish all analysis prior to the final decision. Other elements of the proposal relate to non-network alternatives, and labour costs.

### 3.3.4 Submissions

There are mixed views on the AER's proposal to move the three process-related factors out of the expenditure factors. The ENA opposes this change, whereas Grid Australia supports it.[105] On the other hand, NSPs are generally strongly opposed to amending the obligation on the AER to consider its analysis by removing the reference to the analysis having been published. ETSA, Citipower and Powercor state that the change would curtail a stakeholder's right to be heard on issues material to a regulatory

104 AER, Rule change request, Part B, 29 September 2011, pp. 34-37.

105 ENA, Consultation Paper submission, 8 December 2011, p. 70; Grid Australia, Consultation Paper submission, 8 December 2011, p. 39.

determination, may lead to increased risk of regulatory error, and may also conflict with statutory and common law obligations of procedural fairness, and the ENA comments that the AER has not referred to problems with this factor in recent processes.[106]

Australian Paper comments that it is appropriate to add a catch-all expenditure factor.[107] ETSA, Citipower and Powercor, and Ergon Energy consider that the expenditure factors should continue to be mandatory considerations.[108]

### 3.3.5 Analysis

In respect of the factor relating to the requirement on the AER to consider analysis which it has published, it is necessary to balance competing considerations. On the one hand, stakeholders should be given as much chance as possible to comment on material the AER relies on. This can reduce the risk of regulatory error, and best fits with the principles of procedural fairness and transparency. The AEMC takes the initial view that comments it made in 2006 continue to apply:

> "... the reference to 'published' analysis is intended to ensure that analysis conducted by, or on behalf of, the regulator is made available for public scrutiny, improving the transparency of the overall regime.[109]"

On the other hand, the length of time the AER has under the NER to reach a final regulatory determination is limited and there may be times when it could be unworkable for the AER to have to consult on material prepared for it before a regulatory determination is made. The best way to achieve a balance between these considerations may be for the AER to publish in either the draft or final regulatory determination any analysis it has undertaken prior to that determination. This would allow the regulatory determination process to proceed uninterrupted, but also allow for public scrutiny of that analysis as described by the AEMC in 2006. Scrutiny of material relied on in the final regulatory determination by the AER, which was not relied on for the draft regulatory determination, would be through the right NSPs have to merits review. Such an approach would not prohibit the AER from publishing or consulting on analysis before the draft or final regulatory determination stage, but it would not be obliged to do so. The AER's intent to publish in this way is expressed in the rule change request, though ETSA, Citipower and Powercor express doubt as to whether this is unambiguously required by the NER.[110] The initial view of the Commission is that this lack of clarity could be overcome by clarifying the NER to this effect.

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106 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 60; ENA, Consultation Paper submission, Attachment D, 8 December 2011, p. 12.

107 Australian Paper, Consultation Paper submission, 8 December 2011, p. 20.

108 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 59; Ergon Energy, Consultation Paper submission, 8 December 2011, p. 13.

109 AEMC, *Economic Regulation of Transmission Services*, Draft Rule Determination, 26 July 2006, p. 55.

110 AER, Rule change request, Part B, 29 September 2011, p. 37; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 61.

The "procedural" matters currently included as the first three expenditure factors appear to resemble more closely the procedural requirements found at other places in the NER and it would be appropriate to move these as proposed by the AER. On the other hand, the criteria of demand forecasts and cost inputs are more significant to the AER's consideration of regulatory proposals than the factors and the Commission's initial view is that these should remain as criteria.

The Commission agrees with the AER that it should not be limited to the factors set out in the NER. In order to achieve flexibility, other factors may need to be considered in future. Finally, it should remain mandatory for the AER to have regard to the factors listed. This provides some certainty for stakeholders in what the AER must consider in determining expenditure forecasts. Importantly, this does not mean that every factor must be applied to every aspect of an expenditure determination. Rather, in having regard to the list of factors, the AER may decide that in some cases certain factors are not relevant elements in the making of the AER's decision.

### 3.3.6 Initial position

The Commission's initial view is that it would be appropriate to move the "procedural" factors in the way proposed by the AER and to clarify that the factors are not exhaustive. In terms of the reference to publication of analysis by the AER, the NER should be clarified to make it clear there is an obligation on the AER to publish its analysis with its draft or final regulatory determinations, but no obligation to do so prior to this. The Commission welcomes submissions on its initial views on these issues.

# 4 Capex incentives (and related issues)

**Summary**

- At present, once the AER sets a capex allowance, NSPs are not prevented from undertaking capex beyond the allowance. After a period of time any such "overspend" is included in the NSP's asset base which is used to determine overall revenues and prices for the NSP.
- The AER believes that this creates incentives for NSPs to incur more than efficient levels of capex.
- The AER has proposed a mechanism by which only 60 per cent of such overspend would be included in the asset base.
- The Commission takes the view that the NER do not provide NSPs with an incentive to spend more than the capex allowance, though there may be incentives on NSPs to defer capex, in an inefficient way.
- In addition, capex above the allowance is not subject to regulatory scrutiny at all, which also creates a risk that it may be inefficient.
- The Commission shares concerns raised by stakeholders regarding the AER's 60 per cent proposal, and will consider a range of other options for dealing with the problems identified.

## 4.1 Objective

The objectives for capex incentives and other related issues are set out at the start of the previous Chapter of this paper.

## 4.2 Capex incentives

### 4.2.1 Context

The role of capex incentives is to provide incentives for NSPs to incur efficient capex, and spend no more capex than is necessary for a given level of output. The AER suggests that capex incentives are currently too weak and proposes to amend the regulatory asset base (RAB) roll forward mechanism as a means of strengthening them.

### 4.2.2 Current rules

A NSP's revenues for a regulatory control period are determined by, among other things, applying a rate of return to the underlying asset value, the RAB.[111] The RAB is

111 NER clause 6.5.2 and 6A.6.2.

the asset value assigned to a NSP's network for the purpose of calculating the return on, and depreciation of, capital invested in the NSP. The NER require the RAB to be rolled forward from one period to the next, meaning that the RAB at the start of one regulatory control period, subject to certain prescribed adjustments, is used as the RAB for the next period. One such adjustment is to increase the RAB by all capex incurred by the NSP during the previous regulatory control period.[112]Another adjustment is to decrease the RAB for depreciation of the asset base.[113] This is discussed in section 4.2 of this paper.

As described in the previous Chapter of this paper, a NSP is required under the NER to forecast, in advance, its requirements for capex and opex for a particular regulatory control period. In the regulatory determination, the AER either approves this forecast or replaces it with its own forecast. This forecast (or allowance) is the basis of an incentive for a NSP. If a NSP spends more than its allowance it is required to bear the cost of this overspend for the remainder of the period. If it spends less than the allowance it keeps the total underspend for the period.

Importantly, this effect only lasts for a particular period in respect of a particular capex. At the end of a period, all capex actually incurred is rolled into the RAB. However this capex is not reviewed before it is rolled into the RAB, even if it was in excess of the allowance for the period.[114]

In addition, Chapter 6 of the NER[115] allows for an efficiency benefit sharing scheme (EBSS) for capex.[116] The purpose of an EBSS is to allow for a sharing of efficiency gains and losses between NSPs and users.

### 4.2.3 AER proposal

The AER considers that the current RAB roll forward mechanism creates incentives for NSPs to incur more than efficient levels of capex, particularly in the latter years of the regulatory control period. It suggests that this is particularly an issue where the regulated cost of capital for a NSP is higher than its true cost of capital, or where the NSP is responding to a broader range of incentives, rather than just financial incentives.

The AER claims that this theoretical incentive is supported by actual outcomes. It identifies that the DNSPs in New South Wales spent 19 per cent more than their allowance between 2004-05 and 2007-08.[117] Similarly, it identifies that up to 25 per cent of increases in distribution network charges in New South Wales and Queensland

112 NER clause S6.2.1(e) and S6A.2.1(f).

113 NER clause S6.2.1(e)(5) & S6A.2.1(f)(5).

114 It is noted that in Victoria, the AER does not approve augmentation capex for TNSPs; this is determined instead by AEMO.

115 Chapter 6 of the NER relates to electricity distribution.

116 NER clause 6.5.8(b).

117 AER, Rule change request, Part A, 29 September 2011, p. 10.

during the most recent round of regulatory resets were attributable to capex in excess of allowances in the previous period.[118]

To address this issue the AER proposes to amend the RAB roll forward mechanism such that only capex up to the allowance would be automatically added to the RAB. Under the AER's proposal, any expenditure in excess of the allowance would be subject to a 60/40 sharing factor. That is, 60 per cent of the cost of any expenditure above the allowance would be rolled into the RAB, and therefore be borne by consumers. The remaining 40 per cent would be excluded from the roll forward and instead would be borne by shareholders of the NSP. The AER also proposes that the same incentive arrangements would apply to capex in excess of approved pass through amounts.[119]

### 4.2.4 Submissions

**The problem**

NSPs agree that the incentives for capex efficiency could be improved, suggesting that the current arrangements provide stronger incentives for NSPs to reduce capex earlier in the regulatory control period and weaker incentives towards the end of the regulatory control period. They suggest that this can create unintended financial incentives for inefficient delay or "back loading" of capex.[120]

However, they consider that the AER's claims that the current arrangements provide incentives to spend more than the allowance in the latter years of the regulatory control period has been overstated. In particular, they note that any difference between the allowed cost of capital and the true cost of capital would not affect a NSP's behaviour, as it would require the NSP to expect that any difference in these values will continue into the future over the life of the relevant assets.[121]

Large users broadly agree with the problem identified by the AER suggesting that there is particularly an incentive for government-owned NSPs to overspend their allowance.[122] They also provide some evidence that the government-owned NSPs are less efficient than the privately-owned NSPs. For example, the EURCC observe that government-owned DNSPs are on average half as efficient as privately-owned DNSPs.[123]

118 AER, Rule change request, Part A, 29 September 2011, p. 10.

119 AER, Rule change request, Part B, 29 September 2011, p.52.

120 ENA, Consultation Paper submission, 8 December 2011, p. 30.

121 ENA, Consultation Paper submission, 8 December 2011, p. 30; Grid Australia, Consultation Paper submission, 8 December 2011, p. 44; Jemena, Consultation Paper submission, 8 December 2011, p. 42.

122 EUAA, Consultation Paper submission, 8 December 2011, p. 22; EURCC, Consultation Paper submission, CME Report, 15 December 2011, p. 16.

123 EURCC, Consultation Paper submission, CME Report, 15 December 2011, p. 7.

Small consumer groups are concerned that the current arrangements allow NSPs to roll actual capex into the RAB even where this may not be efficient.[124]

The Victorian DPI states that if funding is constrained, then NSPs will necessarily be more disciplined in prioritising investment and thereby invest more efficiently. If funding is less constrained, then NSPs will tend to be less disciplined in prioritising investments and are more likely to invest inefficiently. It appears to suggest that a key issue is the scarcity of capital and the discipline this creates on spending.[125]

**The AER's proposed solution**

There was limited support from stakeholders for the AER proposal to allow NSPs to only recover 60 per cent of the cost of any capex incurred above the allowance for the regulatory control period.

NSPs are opposed to the proposal and identify a number of concerns. They are concerned that the scheme may lead to the inefficient deferral or avoidance of otherwise efficient and required capex.[126] They also suggest that it may encourage inefficient substitution from capex to opex.[127] NSPs also note that the proposal fails to address existing incentives to defer capex until the end of the regulatory control period.[128] In addition, they are concerned that the scheme does not allow for any flexibility in application between NSPs or for the scheme to be refined over time.[129]

The Major Energy Users Inc. (MEU) does not support the AER's proposal. Other large energy users suggest the proposal merits more detailed assessment.[130] The Victorian DPI is opposed to the proposal suggesting that it could create perverse incentives for NSPs not to invest even where it is efficient to do so.[131]It also suggests that the proposal will provide a greater incentive for NSPs to inflate their forecasts.[132] Alinta Energy is also concerned about the potential impact of the proposal on the security of supply.[133] The SA DMITRE suggests that the AER proposal is not the most effective method of dealing with the issue.[134]

**Other options and potential ways forward**

In general, NSPs consider that a capex incentive scheme should be established through a guideline developed by the AER. This would allow for flexibility in application

124 Consumer Action Law Centre, Consultation Paper submission, 9 December 2011, p. 3.

125 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 5.

126 Grid Australia, Consultation Paper submission, 8 December 2011, pp. 42,44-46.

127 ENA, Consultation Paper submission, Attachment B, 8 December 2011, p. 37.

128 ENA, Consultation Paper submission, 8 December 2011, p. 32.

129 Ibid; Grid Australia, Consultation Paper submission, 8 December 2011, pp. 42,44 .

130 EURCC, Consultation Paper submission, CME Report, 15 December 2011, p. 16.

131 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 4.

132 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 4.

133 Alinta Energy, Consultation Paper submission, 12 December 2011, p. 2.

134 SA DMITRE, Consultation Paper submission, 23 December 2011, p. 4.

between NSPs and refinement over time and would be consistent with the way that existing incentive schemes in the NER, such as the EBSS and the service target performance incentive scheme (STPIS) are developed .[135] They note that the AER already has the discretion to develop an EBSS for capex under Chapter 6 which it has not used.[136] They consider that the AER should be guided in the development of a capex scheme through appropriate criteria in the rules.[137]

There are slightly differing views from large users. The MEU advocate for ex-post reviews of the efficiency and prudency of capex and ex-post optimisation.[138] The EURCC and Australian Paper consider that the AEMC should take a wider perspective on this issue and evaluate a variety of possible regulatory designs that may provide effective incentives to control expenditure by both government and privately-owned NSPs.[139] In this way, Australian Paper notes that price cap regulation has not been successful in the economic regulation of government owned NSPs.[140]

IPART considers it appropriate to include in the NER a range of mechanisms given the ownership and governance arrangements of NSPs. It considers that the AER's sharing mechanism proposal should be supplemented with an ex-post review of expenditure. It also suggests that rolling incentive mechanisms be further explored.[141] A number of other stakeholders also suggest that the AEMC give further thought to ex-post prudency reviews of capex.[142]

The Financial Investor Group does not support ex-post reviews as it suggests they are not consistent with providing incentives for efficiency, nor the certainty necessary to encourage investment.[143]

The Victorian DPI suggest that the most efficient and effective way to address the issue may be changes to governance arrangements which strengthen the discipline around accessing funding, rather than through the economic regulatory regime.[144]

135 Essential Energy, Consultation Paper submission, 14 December 2011, p. 6.

136 SP AusNet, Consultation Paper submission, 8 December 2011, p. 16.

137 ENA, Consultation Paper submission, Attachment B, 8 December 2011, p. 45.

138 MEU, Consultation Paper submission, 8 December 2011, pp. 9,12.

139 EURCC, Consultation Paper submission, CME Report, 15 December 2011, p. 18; Australian Paper, Consultation Paper submission, 8 December 2011, p.23.

140 Australian Paper, Consultation Paper submission, 8 December 2011, p. 23

141 IPART, Consultation Paper submission, 8 December 2011, p. 11

142 SA DMITRE, Consultation Paper submission, 23 December 2011, p. 4; ERA, Consultation Paper submission, 6 December 2011, p. 1; Alinta Energy, Consultation Paper submission, 12 December 2011, p. 2.

143 Financial Investor Group, Consultation Paper submission, 8 December 2011, p. 59

144 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 6

### 4.2.5 Consultants' views

**The problem**

Professor Yarrow concurs with the AER on the existence of a capex incentive problem. He suggests that capex incentive weaknesses are more likely to show up in differences in performance between privately-owned and publicly owned utilities. This is because a private utility might be expected to argue for a generous forecast of capex requirements in order to induce higher regulated prices, but once those prices are set it has obvious incentives to keep costs down, including capital costs. He considers that the differentials in performance of privately-owned and publicly owned NSPs noted by the EURCC might be interpreted as showing some evidence of this, although further work capable of distinguishing such effects from other factors that may be causing changes in capex would need to be done before conclusions could be reached.[145]

He also considers that the AER case on the existence of a capex incentive problem is reinforced by some general economic reasoning. In particular, the existing rules leave a 'supervision gap' in relation to capex above the allowance. He notes that regulatory supervision of capex tends to be based on either an ex-ante or an ex-post basis, or some mixture of the two.[146] He suggests that in the absence of a rationale for there being no supervision of expenditure above the allowance there would appear to be a clear case for closing the gap.[147] Professor Littlechild also agrees that there is a capex incentive problem noting that there is also no investigation of the efficiency of expenditure that is within the allowance under the current arrangements.[148]

**The AER's proposal and other ways forward**

Professor Yarrow does not support the AER's 60/40 proposal suggesting that it would lead to an upward bias in forecasts and discourage efficient investment.[149] He notes that there is scope for further development of capex incentive schemes which he suggests are better developed through negotiation given that the issues in developing the schemes are complicated.[150] He considers that capex incentive schemes should not be hard wired in the rules.[151]

Professor Littlechild also raises concerns with the AER's proposal querying why 60 per cent of the amount should be assumed to be acceptable. Professor Littlechild considers that US experience suggests that ex-post reviews should not be ruled out, but notes that, in order to reduce cost and regulatory risk, there has increasingly been a move to

145 George Yarrow, Preliminary Views for the AEMC, 12 February 2012, p. 12-14

146 George Yarrow, Preliminary Views for the AEMC, 12 February 2012, p. 14

147 Id., p. 15.

148 Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, p. 17

149 George Yarrow, Preliminary Views for the AEMC, 12 February 2012, p. 18

150 George Yarrow, Preliminary Views for the AEMC, 12 February 2012, p. 19.

151 Ibid.

pass-through arrangements, pre-approvals of major capex and price control re-openers. Professor Littlechild suggests that greater customer involvement in setting and monitoring the capex programme could also be relevant. In his view it is necessary to understand why a NSP has exceeded, or might exceed its capex allowance and to take remedial action if necessary. Professor Littlechild also considers that incentive schemes such as "menu regulation" developed by Ofgem should be considered.[152]

### 4.2.6 Analysis

**The problem**

*Incentive to spend more than the allowance*

As noted above, the AER claims that where a NSP's allowed cost of capital is greater than its true cost of capital then this will provide an incentive for a NSP to spend more on capital than what was provided for in its allowance in the latter years of the regulatory control period. Some stakeholders have indicated that this scenario is true for government owned NSPs.[153]

The Commission notes that a NSP could make a judgement, on a forward looking basis, as to the possible difference between its allowed cost of capital and its true cost of capital that might provide a basis to support an overspend. However, the Commission considers that capex incentives should be designed without reference to the cost of capital. That is, capex incentives should not be changed to address a cost of capital issue. Otherwise the capex incentive mechanism may be distorted. We discuss issues related to the cost of capital for publicly owned NSPs in Chapters 5 and 6 of this paper.

Putting the cost of capital issue to one side, the current mechanism provides that a NSP will have to bear the costs of any overspend during a regulatory control period until the start of the next regulatory control period. This is demonstrated in Figure 4.1 and Figure 4.2. There appears to be no other incentive in the NER on a NSP to overspend. The Commission is of the view that the capex incentives in the NER do not create an incentive for a NSP to spend more than its allowance in its regulatory determination.

152 Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, pp. 3-5, 11-13, 17-18.

153 EUAA, Consultation Paper submission, 8 December 2011, p. 23; EURCC, Consultation Paper submission, CME Report, 15 December 2011, p. 16.

**Figure 4.1 NSP spends more than its allowance in year five of the regulatory control period**

In this example, the regulator approves capex of $100 million to build an asset in year five of the regulatory control period. The cost of this capex is to be recovered over the life of the asset through depreciation and a return on capital. The NSP spends $120 million in year five to build the asset i.e. it spends $20 million more than what the regulator allowed. The overall result of this overspend is that the NSP loses $4 million in revenue during the regulatory control period.

| | Regulatory control period | | | | |
|---|---|---|---|---|---|
| **Year** | **1** | **2** | **3** | **4** | **5** |
| Allowed revenue ($m) | 0 | 0 | 0 | 0 | 20 |
| Actual cost to NSP ($m) | 0 | 0 | 0 | 0 | 24 |
| **Revenue impact on NSP ($m)** | **0** | **0** | **0** | **0** | **-4** |

*Note: The example assumes that the allowed and the true WACC are 10%; the asset invested in has a life of 10 years; the costs are incurred and revenues are received on the first day of each regulatory year; and that there is no other capex during the regulatory control period. Note that allowed revenues and NSP's costs are determined by working out the depreciation and the return on capital of the capex.*

**Figure 4.2 NSP sends more than its allowance in year one of the regulatory control period**

In this example, the regulator approves capex of $100 million to build an asset in year one of the regulatory control period. The cost of this capex is to be recovered over the life of the asset through depreciation and a return on capital. The NSP spends $120 million in year one to build the asset i.e. it spends $20 million more than what the regulator allowed. The overall result of this overspend is that the NSP loses $20 million in revenue during the regulatory control period.

| | Regulatory control period | | | | |
|---|---|---|---|---|---|
| **Year** | **1** | **2** | **3** | **4** | **5** |
| Allowed revenue ($m) | 20 | 20 | 20 | 20 | 20 |
| Actual cost to NSP ($m) | 24 | 24 | 24 | 24 | 24 |
| **Revenue impact on NSP ($m)** | **-4** | **-4** | **-4** | **-4** | **-4** |

*Note: The example assumes that the allowed and the true WACC are 10%; the asset invested in has a life of 10 years; the costs are incurred and revenues are received on the first day of each regulatory year; and that there is no other capex during the regulatory control period. Note that allowed revenues and NSP's costs are determined by working out the depreciation and the return on capital of the capex.*

Comparing this example with the example in Figure 4.1 shows that a $20 million overspend in year one of the regulatory control period has a greater impact on an NSPs revenues than the same overspend in year five of the regulatory control period. Similarly, there is a greater incentive to underspend in year one than in year five. Hence, the power of the capex efficiency incentive is stronger at the start of the regulatory control period and is weaker towards the end of the period.

*Declining power of the incentive*

If a NSP spends more than its capex allowance at the beginning of the regulatory control period then it bears the cost of this overspend for longer than it would if it spends more than its capex allowance later in the period. This is also demonstrated in

Figure 4.1 and Figure 4.2. Similarly, the sooner in the regulatory control period a NSP can make efficiency savings (which would enable it to spend less than its allowance) the longer it retains these savings. Thus, the power of the incentive under the current arrangements declines throughout the regulatory control period.

This has two key implications:

- NSPs have a greater incentive to make efficiency gains at the start of the period; and
- an incentive is created for NSPs to defer capex from early in the period to late in the period (also see Figure 4.3).

As the power of the incentive for opex is constant, the declining power of the capex incentive is also likely to increase any incentive to replace opex with capex later in the regulatory control period. This issue is being looked at by the Commission as part of its Power of Choice Review, and was not identified as an issue in the AER proposal.

Overall, this means that there is not a continuous incentive for efficiency gains as there would be in a competitive market. Similarly these incentives create a risk of sub-optimal timing of capex since capex that may be required from an engineering point of view may be delayed. These incentives may also create a risk of the sub-optimal use of inputs.

**Figure 4.3 Example of incentive to defer capex**

In this example, the regulator approves capex of $100m to build an asset in year one of the regulatory control period. However, the NSP builds the asset in year four of the regulatory control period. The asset cost the NSP $100 million to build as allowed for by the regulator. The NSP will therefore be revenue neutral from the transaction. However, the NSP will improve its cashflow i.e. it will have excess revenue until the asset is built. In this way, an NSP will be better off if it defers capex until the end of the regulatory control period.

| | Regulatory control period 1 | | | | | Regulatory control period 2 | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| Allowed revenue ($m) | 30 | 30 | 30 | 30 | 30 | 0 | 0 | 0 | 0 | 0 |
| Actual cost to NSP ($m) | 0 | 0 | 0 | 30 | 30 | 30 | 30 | 30 | 0 | 0 |
| Revenue impact on NSP ($m) | 30 | 30 | 30 | 0 | 0 | -30 | -30 | -30 | 0 | 0 |

*Note: The example assumes that the allowed and the true WACC are 10%; the asset invested in has a life of 5 years; the costs are incurred and revenues are received on the first day of each regulatory year; and that there is no other capex during the regulatory control period. Note that allowed revenues and NSP's costs are determined by working out the depreciation and the return on capital of the capex.*

*Lack of supervision*

The AER's role in respect of capex currently involves assessing NSPs' capex forecasts on an ex-ante basis and rolling actual capex into the RAB. As set out above, there is currently no provision for the AER to review capex after it occurs. This is a concern as without any supervision of this capex there is essentially no assurance that capex above what has been allowed for has been efficiently incurred. Despite this, all actual capex

must be rolled into the RAB. As noted above, Professor Yarrow also considers this to be a problem.

The Commission also notes that currently there is no check on the efficiency of expenditure that was within the allowance as identified by Professor Littlechild. Although, if the projects undertaken are the same or very similar to those the NSP set out in its regulatory proposal then the ex-ante assessment of the projects provides a degree of confidence about the likely efficiency of the expenditure and in these circumstances no further assessments would be required.

*Summary of the Commission's initial view of the problem*

In summary, there are two key issues with the current framework:

- the power of the incentive declines during the regulatory control period which has implications for efficiency incentives, timing of capex and substitution between opex and capex, and

- it does not provide sufficient supervision (ex-ante or ex-post) of capex above the forecast.

**Options**

This section sets out possible solutions to address the problems identified.

*The AER's proposed 60/40 sharing mechanism prescribed in the rules*

As noted above, there has been considerable concern expressed regarding the AER's proposed solution – being the 60/40 sharing mechanism on expenditure above the allowance. The Commission shares a number of these concerns. They include:

- The proposal to prescribe the mechanism in the NER would not enable the scheme to be applied differently to different NSPs, nor would this allow for the scheme to be refined over time. Prescribing a scheme in the NER would also create a barrier to applying the schemes through negotiation.

- The mechanism would not provide a continuous incentive and would provide NSPs with an incentive to defer capex until the end of a regulatory control period.

- Under the mechanism, a level of supervision of spending above forecast by a NSP (ie only 60 per cent of the cost of any overspend is allowed to be recovered) would be provided; however, this supervision would not be tailored to whether the spending is efficient or not.

Given these concerns the Commission is minded to focus on exploring other options for dealing with the problems that have been raised. The Commission supports in principle the concept raised by the AER that incentive arrangements should apply to capex included in approved pass through amounts.

*An efficiency benefit sharing scheme developed in the form of a guideline*

As noted above, NSPs propose that a capex incentive scheme should be empowered by the NER with appropriate criteria developed. They prefer this approach due to the flexibility that it creates for applying and refining the scheme. NSPs consider that the existing EBSS criteria in the NER are broadly appropriate including that the scheme (to the extent practicable) should provide a constant and continuous incentive and to provide for rewards as well as penalties.[154]

This proposal would appear to be able to address the declining incentive issue although this would depend on the criteria that were provided for in the NER and the way that the AER implemented the scheme. In a similar way to the AER's proposal, this approach is likely to only partially address the supervision issue by sharing the cost of any expenditure above forecast between a NSP and its consumers although, once again, this would depend on the details of the scheme.

It should be noted that the AER decided not to develop an EBSS for capex in distribution on the basis that its inclusion could inappropriately incentivise the deferral of capex into future regulatory control periods.[155] The AER considers that if it has discretion to develop capex incentives through a capex EBSS, the NER should permit the option of asymmetric incentive arrangements.[156]

*Ex-post reviews of the prudency and efficiency of capex*

As noted above, there were mixed views from stakeholders on the use of ex-post prudency reviews in submissions. In addition, the AER does not support ex-post reviews on the grounds that they may add to regulatory risk by creating potential for investment write downs and that the evidentiary burden that the regulator must satisfy before it could disallow an investment is so high that ex-post reviews may offer limited protection against inefficient expenditure.[157] While ex-post prudency reviews are allowed for in gas, they have not been used much by the AER in practice.[158]

In 2006 the AEMC determined not to allow for ex-post reviews of the efficiency and prudency of capex as it considered it would undermine incentives to efficiently incur capital costs that were not foreseen at the time of the applicable regulatory determination. That is, it would undermine incentives of the ex-ante cap. It also considered it would contribute to investment uncertainty.[159]

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154 ENA, Consultation Paper submission, Attachment B, 8 December 2011, p. 47.

155 AER, Response to AEMC queries on AER network regulation rule change proposals, 1 February 2012, p. 4.

156 Id., p. 7.

157 AER, Rule change request, Part B, 29 September 2011, pp. 43-44.

158 NGR rule 77(2).

159 AEMC, *Economic Regulation of Transmission Services, Rule Determination*, 16 November 2006, pp. 98-99.

An ex-post review would, however, address the lack of supervision problem raised above. An ex-post review regime could include ex-ante constraints on the standard against which efficiency would be measured when the ex-post review is conducted. Similarly, the scope of an ex-post review could be limited by removing those projects that have passed a regulatory investment test. These suggestions might address some of the concerns referred to above.

*Optimisation of the RAB at regulatory resets*

This solution would involve the RAB being reduced at a regulatory reset to the extent of any assets that are fully or partially unutilised. This option would appear to deal with the supervision issue by removing any incentive to spend more than what is efficient. However, the power of the incentive to underspend will still decline during the regulatory control period under this option. This option is anticipated to be considered by the AEMC in the context of a MEU rule change.[160]

### 4.2.7 Initial position

The Commission agrees that there is no supervision of expenditure above the allowance in the regulatory determination. Given that there is a regime to deal with uncertain projects and unforeseen events during a regulatory control period, and noting that projects identified in a NSP's proposal are not necessarily firm in terms of timing across the regulatory control period and priorities can change in that period, the Commission wishes to understand further the circumstances in which a NSP would need to spend more than its allowance. That is, if there are appropriate safeguards to protect NSPs from risks outside of their control through an uncertainty regime then the Commission would like to explore why any efficient expenditure above the allowance would occur.

To further understand this issue, and to form a basis on which to develop a solution, the Commission anticipates to engage a consultant to undertake further work. The purpose of this work will be to understand the cause and nature of overspends, and the interaction between overspends and the uncertainty regime. This is likely to involve looking at actual over expenditure and discussions with stakeholders including the AER and NSPs.

In addition, the Commission anticipates to undertake further work to understand approaches adopted in other countries and by jurisdictional regulators in Australia. These might include Ofgem's use of menu regulation and the use in the US of ex-post reviews of capex. This analysis will inform the Commission's considerations of the options discussed above, including understanding the appropriate strength or form of any incentive on NSPs regarding capex under or overspends.

In general, the Commission is reluctant to prescribe in the NER a detailed solution to the problems raised above. Instead, it would prefer to establish principles and enable

160 MEU, Optimisation of Regulatory Asset Base and Use of Fully Depreciated Assets Rule change request, October 2011.

the AER to develop the solution consistently with those principles. The work identified above will inform the development of principles, and assist the Commission to consider whether it would in fact be more appropriate to prescribe a particular approach in the NER (eg ex-post reviews). The Commission will be looking to engage with stakeholders in the development of options for dealing with capex incentive issues.

### 4.2.8 Issues for further comment

| | |
|---|---|
| **Question 7** | **In what circumstances would an NSP need to spend more than its allowance under the NER?** |
| **Question 8** | **What is the best option for dealing with the capex incentive issues identified in this paper?** |

## 4.3 Actual or forecast depreciation

### 4.3.1 Context

Depreciation in this context relates to the allocation of the cost of the assets over the lives of the assets. The AER proposes that it have discretion in Chapter 6A of the NER to use either actual or forecast depreciation to establish the RAB at the start of a regulatory control period.[161] The use of actual or forecast depreciation to establish the RAB impacts on the strength of the capex efficiency incentive.

### 4.3.2 Current rules

As noted in the previous section, the NER require the RAB to be rolled forward from one period to the next, meaning that the RAB at the start of one regulatory control period, subject to certain prescribed adjustments, is used as the RAB for the next period. One such adjustment is to increase the RAB by all capex incurred by the NSP during the previous regulatory control period.[162] Another adjustment is to decrease the RAB by the amount of depreciation incurred by the NSP during the previous regulatory control period (including the depreciation of the RAB since the previous regulatory control period and depreciation of the capex incurred during the period).[163]

Chapter 6A of the NER requires the AER to use actual depreciation to roll forward the RAB.[164] Chapter 6 of the NER gives the AER discretion to use either forecast or actual depreciation.[165] Actual depreciation is based on actual capex incurred for the previous

161 Chapter 6A of the NER relates to electricity transmission.

162 NER clause S6.2.1(e) and S6A.2.1(f).

163 NER clause S6.2.1(e)(5) & S6A.2.1(f)(5).

164 NER clause S6A.2.1(f)(5).

165 NER clause S6.2.1(e)(5) and 6.12.1(18).

regulatory control period. Forecast depreciation is based on what the forecast capex was for the period. The use of actual or forecast depreciation to establish the RAB impacts on the strength of the efficiency incentive for capex.

### 4.3.3 AER proposal

The AER considers that it should have discretion to determine whether forecast or actual depreciation is used to roll forward the RAB in Chapter 6A of the NER making it consistent with Chapter 6 of the NER.[166] It puts forward that this would enable it to adopt a high powered or a low powered depreciation incentive and to achieve balanced capex incentives.[167] In addition, the AER suggests that it may not always be appropriate for it to adopt actual depreciation. For example, forecast depreciation could apply when a significant proportion of the forecast capex reflects uncontrollable factors as this would reduce the chance of windfall gains and losses.[168]

### 4.3.4 Submissions

ENA agrees with the AER noting that under certain circumstances the use of forecast depreciation is preferable. It suggests that there is no evidence in gas, where forecast depreciation is typically adopted, that exclusion of depreciation from the incentive framework leads to inefficient substitution of operating inputs in favour of capital inputs as suggested by the AEMC in 2006. In addition, the ENA considers that there is no compelling need for divergent approaches between electricity transmission and distribution on this matter.[169]

Grid Australia considers that giving the AER discretion to apply actual or forecast depreciation is an improvement on the current arrangements. However, the use of actual depreciation as an incentive tool is a second best option for enhancing capex incentives through an EBSS as actual depreciation distorts incentives between short lived and long lived assets. Grid Australia therefore suggests that the AEMC consider prescribing forecast depreciation in the NER.[170]

The EURCC and Australian Paper prefer one method to be locked in to give investors and managers certainty about the incentives under which they operate. They prefer that actual depreciation be prescribed in the NER due to the fact that this creates a stronger incentive not to overspend against their capex allowance.[171]The Victorian DPI

166 AER, Rule change request, Part B, 29 September 2011, p. 44.

167 Ibid.

168 Id., pp.45,46.

169 ENA, Consultation Paper submission, 8 December 2011, pp. 34-35.

170 Grid Australia, Consultation Paper submission, 8 December 2011, pp. 54-55.

171 EURCC, Consultation Paper submission, CME Report, 15 December 2011, pp. 16-17; Australian Paper, Consultation Paper submission, 8 December 2011, p. 23.

support the AER's proposal noting that it would allow the AER to take into account the circumstances of each jurisdiction.[172]

### 4.3.5 Analysis

As noted above, the use of actual or forecast depreciation is linked to capex incentives and needs to be considered on that basis.

The Commission agrees with the explanation of the impact of using actual or forecast depreciation in the ENA submission. That is, under the actual depreciation approach, if a NSP underspends or overspends the expenditure allowance, the depreciation adjustment to the capital base will be recalculated to reflect the difference between actual and forecast capex. In a case in which a NSP spends less than it was allowed by the regulator, less depreciation will be removed from the capital base than the funds that were recovered during the regulatory control period. In a case of exceeding the regulatory allowance the reverse is true and the NSPs will incur a symmetrical loss. On the other hand, a forecast depreciation approach has a neutral effect on the capex incentives because depreciation adjustment will be the same regardless of the actual expenditure outcome.[173] This is demonstrated in the worked example in Figure 4.4.

172 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 7.

173 ENA, Consultation Paper submission, 8 December 2011, p. 34.

**Figure 4.4 Worked example of the impact of using actual or forecast depreciation**

**Overspend scenario**

| | |
|---|---|
| | Asset life = 10 years |
| Forecast capex = $100m | Actual capex = $120m |
| Forecast depreciation = $10m/year | Actual depreciation = $12m/year |

Actual depreciation: RAB + 120 – 60 = RAB + 60
Forecast deprecation: RAB + 120 – 50 = RAB + 70

**Underspend scenario**

| | |
|---|---|
| | Asset life = 10 years |
| Forecast capex = $100m | Actual capex = $80m |
| Forecast depreciation = $10m/year | Actual depreciation = $8m/year |

Actual deprecation: RAB + 80 – 40 = RAB + 40
Forecast depreciation: RAB + 80 – 50 = RAB + 30

Note:
- Scenarios assume expenditure occurs on the first day of the regulatory control period
- Financing carry costs are the same under both actual and forecast depreciation
- Revenue in period in which expenditure occurs is same in all four scenarios = 50

**Conlcusions from scenarios**

- Where forecast depreciation is used, the amount of depreciation coming off a NSPs RAB will be the same whether it overspends or underspends compared to its allowance (e.g. $50 million in the above scenarios). This means that there is no additional incentive for an NSP to underspend or not overspend using forecast depreciation.

- Under actual depreciation, a NSPs RAB is lower if it overspends compared to if forecast depreciation is used (RAB + 60 compared to RAB +70 in the above scenarios), and higher if it underspends compared to if forecast depreciation is used (RAB + 40 compared to RAB + 30 in the above scenarios). This means that actual depreciation creates a greater incentive not to overspend and a greater incentive to underspend against the allowed expenditure.

However, the Commission notes the comments from Grid Australia on the impacts of using actual depreciation on incentives between short lived and long lived assets. The Commission also notes the recent decision from the Tribunal on the appeal by the Victorian Minister for Energy on the AER's decision to use actual depreciation in its recent regulatory determinations for the Victorian DNSPs.[174] Although the Tribunal found that the Minister had failed to make out any ground of review on the matters that were raised, the Commission considers that the appeal raises some issues on the impacts of using actual or forecast depreciation that warrant further investigation. One such issue is whether the use of actual depreciation leads to higher forecasts by NSPs.

Given the complexities of this issue, the Commission would like to explore in more detail how using actual or forecast depreciation affects a NSP's behaviour.

174 Application by United Energy Distribution Pty Limited [2012] ACompT 1 (6 January 2012).

### 4.3.6 Initial position

The Commission will engage a consultant to advise on the factors to consider in making a decision on whether the AER should have discretion to use actual or forecast depreciation or whether a particular approach should be prescribed in the NER. This work would also either:

- assist the Commission in determining whether the AER should be guided in any discretion it is given (and if so how); or
- assist the Commission in determining which method of depreciation should be prescribed in the NER.

### 4.3.7 Issues for further comment

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

## 4.4 Uncertainty regime

### 4.4.1 Context

For the purposes of this directions paper, "uncertainty regime" in the NER comprises contingent projects, capex reopeners and pass through events. These mechanisms deal with expenditure that is required to be undertaken during a regulatory control period but which is not able to be predicted with reasonable certainty at the start of the period. A more accessible uncertainty regime will on the one hand facilitate all necessary capex or opex being undertaken, though on the other hand it may reduce the incentive to undertake only efficient capex and opex. The AER has proposed a broader uncertainty regime to balance its proposals for stronger capex incentives and more discretion in respect of capex/opex allowances. The uncertainty regime is important for allocating risks to the party best able to deal with them, including appropriately sharing the risks of external events.

The Commission has recently received a related rule change request from Grid Australia on the cost pass through arrangements in Chapter 6A of the NER. A consultation paper was published on 2 February 2012 which is available on the AEMC's website. While that does not directly relate to the issues proposed by the AER in the current rule change request, there is some overlap in respect of both pass through events and capex reopeners. The Commission will bear in mind the likely direction of that rule change process as this one progresses.

### 4.4.2 Current rules

Contingent projects are provided for in chapter 6A (transmission), but not chapter 6 (distribution). Under the contingent project regime, the AER may as part of a

regulatory determination approve a project which is uncertain but which has a clearly defined trigger event. The relevant capex/opex is not included in the total of forecast capex/opex for the period.[175] However if the trigger event occurs during the regulatory control period, the NSP can apply to the AER for the AER to determine an additional portion of revenue to be recovered during the period based on the additional required capex and opex.

Capex reopeners are also found in chapter 6A but not chapter 6. Where an event occurs during a regulatory control period which requires a NSP to undertake additional capex equivalent to five per cent or more of the RAB for the first year of the period, the NSP can apply to the AER for the AER to determine an additional portion of revenue to be recovered during the period.[176]

Pass through events are events specified in the rules (or by the AER in a regulatory determination) for which additional revenue may be allowed during a regulatory control period. In transmission the pass through amount must be at least one per cent of the maximum allowed revenue for the year, whereas in distribution the materiality threshold is not specified.[177]

### 4.4.3 AER proposal

The AER proposes to include capex reopeners and contingent project provisions in Chapter 6 of the NER.[178] In general, these would operate in distribution in the same way as they currently operate in transmission. The threshold for a capex reopener would be five per cent of the RAB for the first year of the period (as in transmission). The default threshold for a contingent project in distribution would be $10m, however the AER has also proposed that it have the ability to specify a different threshold for both distribution and transmission contingent projects in guidelines. In respect of pass through events, the AER's proposal is that a materiality threshold of one per cent of the annual revenue requirement should be applied to distribution.[179] Finally, the AER has also proposed that, where as a result of a pass through application the AER allows capex which is fully recovered during the regulatory control period in which the relevant event occurs, the capex should not be rolled into the RAB at the next regulatory determination.

### 4.4.4 Submissions

In general, NSPs are concerned that the uncertainty regime does not overcome the problems caused by the AER's proposals in respect of capex/opex allowances, and capex incentives.[180] At a specific level, many NSPs, and the Victorian DPI, raise

175 NER clause 6A.8.1.

176 NER clause 6A.7.1.

177 NER clause 6A.7.3 and clause 6.6.1.

178 AER, Rule change request, Part B, 29 September 2011, pp. 46-52.

179 AER, Rule change request, Part B, 29 September 2011, p. 50.

180 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 74.

concerns over the applicability of a contingent projects regime to distribution, where projects tend to be smaller, and have less lead time, than in transmission.[181] Consumer groups are opposed to the AER's proposals on the uncertainty regime on the basis that broadening the uncertainty regime could weaken expenditure discipline, as well as the strength and certainty of the price cap.[182] Retailers are concerned that the greater scope for reopening regulatory determinations mid-period will make it harder to predict prices in advance.[183] Ausgrid is opposed to both of the proposed changes to the pass through regime.[184] Alternative solutions proposed in submissions include adopting a pass through threshold in distribution of $1m, instead of one per cent of the annual revenue requirement, and applying an "excess" so that the NSP is required to absorb the first portion of a claim before a capex reopener, contingent project or pass through is possible.[185]

### 4.4.5 Analysis

The changes that have been proposed to the uncertainty regime aim to balance other changes the AER proposes in respect of capex/opex allowances and capex incentives. To an extent, then, the need for these changes to the uncertainty regime may depend on whether those other proposed changes are made as part of this rule change process. Despite this, the Commission has considered whether there is any other justification for the changes proposed to the uncertainty regime.

The Commission notes the comments it made in the Chapter 6A rule determination in respect of the uncertainty regime.[186] NSPs operate in an uncertain environment where uncontrollable, external factors can impact the services provided by the NSP and the costs the NSP incurs. In a competitive market, a NSP is able to adjust its behaviour in response to these factors and then seek to recover its costs from consumers. Also, in competitive markets, suppliers of the service have the choice as to whether or not to provide the service to particular consumers. NSPs on the other hand are generally required to supply services when consumers seek them, which means a NSP can be required to operate in situations where its equipment is exposed to significant and potentially uninsurable risks. Setting the regulatory framework to allow recovery of uncontrollable costs in this way for NSPs should promote efficient investment in electricity services, contributing to the NEO. This is part of the process of allocating risks to the party best able to deal with them. The Commission recognises that allowing recovery for external factors during a regulatory control period will reduce certainty

181 UE and MG, Consultation Paper submission, 8 December 2011, p. 10, Victorian DPI, Consultation Paper submission, 8 December 2011, p. 5.

182 EUAA, Consultation Paper submission, 8 December 2011, p. 24; EURCC, Consultation Paper submission, 15 December 2011, p. 17.

183 Origin Energy, Consultation Paper Submission, 8 December 2011, p. 3.

184 Ausgrid, Consultation Paper submission, 8 December 2011, pp. 30-32.

185 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 81; EURCC, Consultation paper submission, 15 December 2011, p. 18.

186 AEMC, *Economic Regulation of Transmission Services, Rule Determination*, 16 November 2006, pp. 54, 104.

overall (such as in respect of prices) and may dampen the incentive effects of an ex-ante revenue allowance. However these risks may be reduced by correctly setting the parameters of the uncertainty regime, such as the thresholds. If a cost is beyond the power of the NSP to control, the incentive regime has little effect anyway.

It is also relevant to note here the link to the cost of capital. As Professor Littlechild points out, if pass throughs and reopeners are broadened, the NSP is bearing less of the risk and its cost of capital should be reduced, since cost of capital reflects the risk to which a NSP is exposed.[187] Less clear is whether this principle would apply to contingent projects to the same extent as capex reopeners and pass throughs.

On the whole, the Commission's initial view is to support extending capex reopeners and contingent projects to distribution. While distribution projects are likely to be smaller, and with less lead time, than in transmission, this challenge can be overcome by setting the threshold for contingent projects at an appropriate level. The Commission has not yet considered what this threshold should be. It may be appropriate to link this threshold to inflation, as proposed by Victorian DPI.[188] There appears to be merit in giving the AER the discretion to set the contingent project threshold in guidelines.

In respect of pass through events, while the Commission notes Ausgrid's arguments in favour of flexibility, it takes the initial view that there is more benefit in having a materiality threshold which is certain. There would also be benefit in introducing a provision which prevents double recovery in the event capex is recovered as part of a pass through, although the Commission expects it is unlikely that the AER would often consider it appropriate to allow the full recovery of capex for long lived assets within a single regulatory control period.

### 4.4.6 Initial position

There appears to be merit in the AER's proposals in respect of the uncertainty regime, although the details of the way it would apply need to be considered further. It would also be appropriate to revisit the overall need for the changes once the response to the proposals on capex/opex allowances and capex incentives are developed further.

### 4.4.7 Issues for further comment

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|---|---|
| **Question 10** | **The Commission notes the comments by the ERAA on the need for a rigorous approach to assessing capex reopeners and contingent projects.[189] The Commission seeks submissions from retailers on any other options for minimising the impact of capex reopeners and contingent projects on retailers.** |

187 Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, p. 18.

188 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 5.

189 ERAA, Consultation Paper submission, 8 December 2011, p. 2.

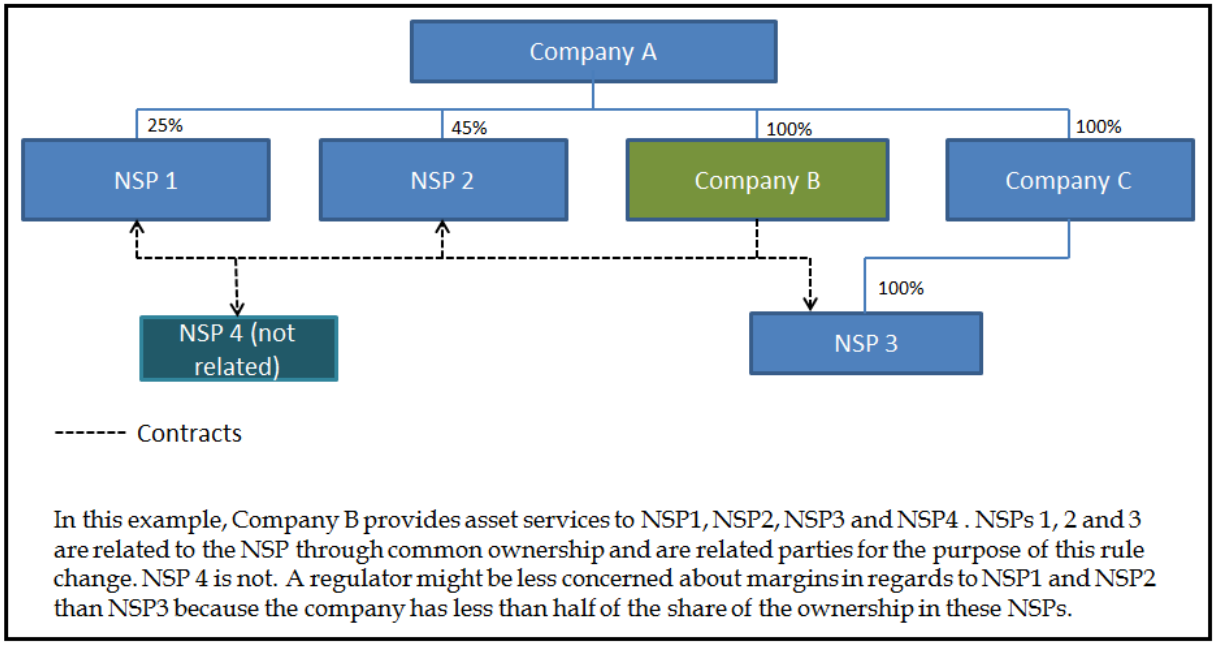
**Question 11** **More extensive use of the uncertainty regime means regulatory arrangements more closely resemble commercial contracts. Is this appropriate?**

## 4.5 Related party margins and capitalisation changes

### 4.5.1 Context

Related parties are companies that are related to a NSP through common ownership. In some cases, related parties provide management and operational services to NSPs. The term "margin" is used to reflect any difference between a contract price and a contractor's actual direct costs. The AER considers that the NER do not create sufficient incentives for NSPs to seek efficient outcomes in regard to capitalised related party margins.[190] An example to illustrate what related party arrangements may look like is provided in Figure 4.5. In addition, the AER considers the NER creates perverse incentives for NSPs to change their approaches to capitalising overheads during a regulatory control period.[191] The AER proposes changes to the RAB roll forward mechanism to deal with these issues.

**Figure 4.5 Example to illustrate related party arrangements**




In this example, Company B provides asset services to NSP1, NSP2, NSP3 and NSP4 . NSPs 1, 2 and 3 are related to the NSP through common ownership and are related parties for the purpose of this rule change. NSP 4 is not. A regulator might be less concerned about margins in regards to NSP1 and NSP2 than NSP3 because the company has less than half of the share of the ownership in these NSPs.

### 4.5.2 Current rules

The NER provide that the AER, in assessing a capex forecast, must have regard to the extent to which the forecast is referable to arrangements with a third party that do not

190 AER, Rule change request, Part B, 29 September 2011, p. 54.

191 AER, Rule change request, Part B, 29 September 2011, p. 53.

reflect arm's length terms.[192] The purpose of this provision is to allow the AER to disregard or give lesser weight to reported costs, where the AER has reason to believe that they were not struck on an arm's length basis.[193]

As noted above, the NER also provide that the previous value of the RAB must be increased by the amount of all capex incurred during the previous regulatory control period.[194] However, this capex is not reviewed before it is rolled into the RAB, even if it is in excess of forecast, or if it was deemed not to be efficient by the AER at the time of the regulatory determination. Similarly, the RAB may also include expenditure that was allowed for as opex in the regulatory determination but gets treated as capex due to changes in the capitalisation policy of the NSP.

### 4.5.3 AER proposal

The AER identifies that there are circumstances where margins paid by NSPs to their related parties do not reflect efficient costs and are excluded from the forecast expenditure. However, it notes that related party margins may, in some circumstances, be capital in nature and therefore meet the requirement of being capex incurred during the previous regulatory control period for the RAB roll forward.[195]

The AER identifies a similar issue where a NSP capitalises opex during a regulatory control period. In this scenario, the AER notes that a NSP is compensated twice for the same expenditure, once in forecast opex, and again through depreciation and return on capital once it is rolled into the RAB.[196]

To solve the related party margin issue the AER proposes that it be able to exclude these margins from the RAB where they were not permitted on an ex-ante basis and where the AER determines (ex-post) that they are not efficient. Similarly, the AER proposes that it be able to exclude capitalised overheads from the RAB where these had not been allowed for by the AER when the capex was determined.[197]

### 4.5.4 AER response to request for further information

To further understand the AER's view on the interaction between the overall capex incentives and the proposals on related party margins the Commission sought further information from the AER. In response to this request the AER suggests that stronger capex incentives would not deal with the related party margin issue because there will still be circumstances where a NSP has an incentive to inefficiently incur related party margins where these inefficient margins are only partly recoverable under the regulatory regime. The AER suggests that the only way to remove the incentive for

192 NER clause 6A.6.7(e)(9) and 6.5.7(e)(9).

193 AEMC, *Economic Regulation of Transmission Services, Rule Determination*, 16 November 2006, p. 118.

194 NER clause S6.2.1(e) and S6A.2.1(f).

195 AER, Rule change request, Part B, 29 September 2011, p. 53.

196 AER, Rule change request, Part B, 29 September 2011, p. 54.

197 AER, Rule change request, Part B, 29 September 2011, p. 55.

NSPs to incur inefficient related party margins in full is to disallow in full the recovery of those inefficient margins.[198]

The AER suggests that the issue is specific to related party margins because the financial position of the NSP's shareholders (and therefore the NSP's incentives) depend not just on the actions of the NSP but also on the actions of the related party. It suggests that from the perspective of the NSP's and related party's parent company, no real financial cost is borne by the shareholders of the NSP in relation to a related party margin. That is, costs incurred by the NSP are offset by the revenue earned by the related party contractor.[199]

The AER suggests that even if only some of the margin is recoverable from consumers (ie where a NSP overspends its allowance) the NSP still has an incentive to pay a margin to its related party because, while the NSP incurs a net loss (portion of margin recoverable through regulated revenues minus whole contract margin incurred) from this transaction, the related party makes a larger net gain (whole contract margin received minus no costs). This leads to an overall net gain to the NSP's and related party's common shareholders. In addition, the AER notes that it is also concerned about the recovery of related party margins (that would not pass its assessment approach) where a NSP underspends its capex allowance noting that, in this circumstance, the benefit to the shareholder would be even greater.[200]

### 4.5.5 Submissions

Stakeholders broadly agree there is a problem.[201] However, NSPs do not support the AER's proposal on the issue. There are concerns that the AER's proposal is ambiguous and that it may unreasonably limit the expenditure that may be rolled into the RAB to the actual amount as determined in the regulatory determination.[202]Jemena is concerned that it creates high powered asymmetric incentives and could raise potential barriers to changes in NSP structures and contracting arrangements.[203] NSPs have different views on the way forward. Jemena sees scope for ex-post reviews of overspends on related party margins and capitalisation policy changes.[204] ETSA, Citipower and Powercor suggest related party margins should be included in the RAB where they would be considered efficient under the AER's framework for determining

198 AER, Response to AEMC queries on AER network regulation rule change proposals, 1 February 2012, p. 7.

199 AER, Response to AEMC queries on AER network regulation rule change proposals, 1 February 2012, p. 8.

200 Ibid.

201 Aurora Energy, Consultation Paper submission, 15 December 2011, p. 9; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 20,84; Victorian DPI, Consultation Paper submission, 8 December 2011, pp. 8-9.

202 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 20, 21, 84, 85.

203 Jemena, Consultation Paper submission, 8 December 2011, p. 55.

204 Id., p. 56.

whether such margins are efficient in the previous regulatory determination. They suggest a similar approach for capitalised overheads.[205]

### 4.5.6 Consultants views

Professor Yarrow considers there is potentially an argument for policy concerns arising from the fact that cost attributions across regulated/unregulated activities boundaries tend to be a persistent source of regulatory problems in that companies tend to have incentives to load costs on to the regulated activities to induce higher allowed prices/revenues. However, he suggests it would be better to address the issue via a more general development of capex incentives rather than by writing specific disallowances into the rules which could greatly increase the risk of unintended outcomes.[206]

### 4.5.7 Analysis

The Commission acknowledges there is an issue in relation to changes in capitalisation policy by NSPs during a regulatory control period because it appears to result in double recovery for the same expenditure. There are no stakeholders that appear to disagree with this. However, the Commission notes that stronger capex incentives, through an EBSS for example, may deal with this issue by removing the incentive to capitalise opex inefficiently.

In respect of related party margins, the Commission seeks submissions on how, and to what extent, the incentive for a NSP to overspend or underspend varies 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. Understanding the magnitude of this issue is necessary to ensure that any solution will address the specific problem and be proportionate. It is also important that any rule change to address this issue provides incentives that are complementary to the other incentives for efficient capex.

The AER states that if a NSP using a related party overspends due to declared higher related party margins then, because the parent company keeps the higher related party margin, the NSP has an extra incentive to overspend compared to other NSPs. In this regard, the Commission would like to understand further the degree to which the parent company would be better off if the higher related party margins are due to genuine higher costs.

The Commission would also like to receive submissions on the relationship between how much goes into the RAB and how much the related party is paid. However, in principle the Commission considers how much the related party is paid is ultimately a matter between the two companies, in the same way that how much any other NSP pays a third party contractor is a matter between the two parties. More relevant, as a

205 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 21, 84, 86.

206 George Yarrow, Preliminary Views for the AEMC, 12 February 2012, p. 19.

matter of principle, is how much consumers pay for the asset that is built or the service that is provided, and whether the incentives are appropriate to ensure that consumers do not pay more than is efficient.

### 4.5.8 Initial position

The Commission's initial view is that there is an issue in relation to changes in capitalisation policy by NSPs during a regulatory control period and that the solution proposed by the AER may be appropriate. However, if stronger capex incentives are applied, such as through an EBSS for capex, this may also address some or all of the problem.

The Commission would like to understand further the strength of the additional incentive for NSPs to not seek efficient outcomes in regard to related party margins than there is for other costs. The Commission proposes to engage consultants to assess the strength of the incentive for a company in theory and in practice, having regard to all the relevant factors that affect the incentive. This is likely to involve some direct discussions with the AER and NSPs to understand the issue from a practical perspective. The Commission will then assess options in the light of the conclusions of the consultant's report. As part of this assessment the Commission will also have regard to how regulators in other countries address this issue.

### 4.5.9 Issues for further comment

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| **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?** |

## 4.6 Other incentive schemes

### 4.6.1 Context

The AER suggests that it should have the power to develop incentive schemes outside of those already provided for in the NER to enable the regulatory framework to keep pace with developments in this area.

### 4.6.2 Current rules

Chapters 6 and 6A of the NER make provision for particular types of incentive schemes. For example, Chapter 6A of the NER requires the AER to develop an EBSS for opex and a STPIS[207]. In addition to an EBSS for opex and a STPIS, Chapter 6 allows the AER to develop an EBSS for capex and distribution losses and a demand management incentive scheme.[208] These schemes are applied to individual NSPs at the time of the regulatory determination. The AER must develop these schemes having regard to a number of principles.[209]

There is no specific power for the AER to develop other incentive schemes.

### 4.6.3 AER's proposal

The AER observes that the practice in incentive schemes is continually evolving. In the absence of provisions in the NER which allow for new schemes, a rule change would be required to implement them, which is cumbersome and overly costly. Although the AER does not currently endorse any particular new incentive scheme, it proposes that it be allowed to introduce new incentive schemes where it considers that there are benefits to consumers arising from the scheme.[210]

The AER proposes that it would have to take into account a number of principles in developing and implementing any new schemes. These are:

- the benefits to consumers likely to result from the scheme are sufficient to warrant any reward or penalty under the scheme;
- that the possible effects of the scheme on incentives for the implementation of non-network alternatives are taken into account;
- that incentives are sufficient to offset any financial incentives NSPs may have to reduce costs at the expense of service levels;

207 NER clause 6A.6.5(a) and 6A.7.4(a).

208 NER clause 6.5.8(b) and 6.6.3(a).

209 See for example, NER clause 6.5.8(c).

210 AER, Rule change request, Part B, 29 September 2011, p. 56.

- that the willingness of the consumer or end user to pay for improvements resulting from the scheme is taken into account; and

- that financial or non-financial targets and service standards set by the scheme do not put the safe and reliable operation of the electricity transmission or distribution networks at risk.[211]

In addition, the AER suggests that it does not have discretion as to whether to apply the existing incentive schemes to NSPs at the time of a regulatory determination in Chapter 6A of the NER (as it does in Chapter 6 of the NER). It proposes to amend Chapter 6A of the NER such that the AER would have discretion as to whether or not to apply the existing schemes at the time of the regulatory determination. This would also make Chapter 6A of the NER consistent with Chapter 6 of the NER.[212]

### 4.6.4 Submissions

NSPs did not agree with the problem identified by the AER or its proposal. Their views are generally reflected by Grid Australia which states that the AER has not identified in what way its existing discretions prevent it from developing new schemes, or any schemes applied internationally that could not be developed within the existing framework. It suggests that if a proposed incentive scheme is sufficiently unique that the current discretions in the NER are insufficient for its development and implementation, then such a change is important enough to be subject to the transparency and rigour of the full rule making process. It considers that doing so, supports the governance framework in the NEM and provides recognition to the discretions afforded to the AEMC and the AER.[213]

In the event that such discretion is given to the AER, ENA suggest that improved guidance will be required to ensure that the development of incentive schemes takes into account such issues as consistency with national access and pricing principles and revenue impact on regulatory risk.[214]

ETSA, Citipower and Powercor suggest that the AER's criteria should be supplemented with the additional following criteria:

- any incentive scheme should be symmetric in nature consistent with the policy objectives underlying the inclusion of this criteria in respect of the development of the EBSS under the NER;

- the desirability of incentive schemes that are simple to administer; and

211 AER, Rule change request, Part B, 29 September 2011, p. 57.

212 Ibid.

213 Grid Australia, Consultation Paper submission, 8 December 2011, p. 52.

214 ENA, Consultation Paper submission, 8 December 2011, p. 37.

- the desirability of ensuring that financial or non-financial targets set by the scheme do not put the safe and reliable operation of the network at risk, and any other regulatory obligation or requirement to which the DNSP is subject.[215]

Grid Australia suggests that the principles proposed by the AER are significantly broader than the current principles for incentive schemes, such that some existing safeguards may be lost. In particular, there are no protections such as revenue at risk or any requirement to consider the risk created by the scheme. [216]

The Victorian DPI supports the AER's proposal suggesting that the economic regulatory regime is not able to continually evolve in line with best practice. [217]

### 4.6.5 Consultants' views

Professor Littlechild is supportive of the AER, suggesting that there is scope for innovation. In addition, he notes that the proposal reflects the way that regulation is developing elsewhere.[218]However, he notes that incentive schemes rely on considerable information and judgement by the regulator to design the schemes and the responses of the companies may not be entirely predictable, nor the resulting levels of profit or loss.[219]

Professor Littlechild also suggests that two of the criteria put forward by ETSA, Citipower and Powercor seem redundant; that is, desirability of simple to administer schemes, and not putting safe and reliable operation of the network at risk. In addition, he notes that the requirement that any scheme be symmetric in nature would be unduly restrictive and likely to stifle innovation.[220]

### 4.6.6 Analysis

There are a number of incentive schemes developed by Ofgem in Great Britain. These include, for example the use of menu regulation (also mentioned earlier in this Chapter of the paper) which aims to give the company an incentive to reveal its true thinking, and to reward those companies that correctly predict what consumers will do and invest accordingly. A more specific example is the distributed generation incentive framework which provides financial incentives on DNSPs to connect to distributed generation.

Given the use of incentive schemes overseas, the Commission considers that there might be value in additional incentive schemes being developed in Australia from time to time. In addition, it considers that the current rule change process creates a big

215 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 22, 90-91

216 Grid Australia, Consultation Paper submission, 8 December 2011, p. 53.

217 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 9.

218 Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 February 2012, p.19.

219 Id., p. 11.

220 Id., p. 19.

hurdle to introduce a new incentive scheme. However, the Commission also notes Professor Littlechild's comments about the difficulties in designing incentive schemes and considers that there is a risk that new incentive schemes could be introduced that lead to unexpected and perhaps unwelcome outcomes.

The Commission considers that one way of mitigating that risk would be to allow the AER to develop small scale pilots or test schemes within an environment that limits the sum of money at risk and the length of time of the scheme prior to the AER submitting a rule change. The test or pilot would also give a much better basis for assessing whether such a proposed rule change would enhance the NEO.

Given that the schemes that the AER might adopt are unknown the criteria that should guide the AER in its development should be reasonably broad. Criteria that are too specific could stifle innovation. One potentially broad criterion that appears to be missing from the AER's proposed criteria is the requirement for the AER to consider the interaction of the scheme with other incentive schemes in the framework.

### 4.6.7 Initial position

The Commission's initial view is that the rule change process may be overly burdensome for introducing new incentive schemes, particularly where these schemes may need to be tested before their true value can be determined.

The Commission is also of the initial view that the NER should allow the AER to develop small scale pilots or test schemes within an environment that limits the sum of money at risk and the length of time of the scheme prior to the AER submitting a rule change.

Finally, the Commission's initial view is that it is appropriate that the AER have discretion to determine whether incentive schemes should apply at the time of a regulatory determination in Chapter 6A of the NER, consistent with Chapter 6.

### 4.6.8 Issues for further comment

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|---|---|
| **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?** |

## 4.7 Shared assets

### 4.7.1 Context

It may be appropriate for the regulatory framework to allow for consumers to be compensated for assets used for providing services which are not regulated, since this may encourage more efficient use of electricity services with respect to price. This issue is likely to become more relevant in light of the potential for electricity network assets (such as poles and pits) to be used to provide access for the National Broadband Network.

### 4.7.2 Current rules

The current rules do not provide for compensation for consumers where an asset is used for providing non-regulated services. An exception to this is in Queensland, where a mechanism developed by the Queensland Competition Authority has been grandfathered in the rules.[221]

### 4.7.3 AER proposal

The AER proposes mechanisms to allow consumers to be compensated where distribution assets are used to provide non-standard control services.[222] One option is for an ex-ante revenue adjustment to the building blocks calculation. Alternatively, there could be a control mechanism adjustment. The AER would signal its decision in the relevant framework and approach paper, with the decision made in the final regulatory determination. No equivalent change is proposed for transmission assets.

### 4.7.4 Submissions

In general, stakeholders support the concept that where assets used to supply standard control services are shared with other services, consumers should receive some compensation. A number of NSPs, however, consider that in order to retain flexibility no mechanism should be provided in the NER.[223]ETSA, Citipower and Powercor state that in order to maintain predictability and transparency the AER should be required to set out its approach to any adjustment in the framework and approach paper, and adhere to this approach unless there are any unforeseen circumstances.[224]United Energy and Multinet Gas (UE and MG) do not support the AER's proposal on the basis that it is tantamount to transferring the value of existing assets out of the RAB, and network prices should be insulated from the profits and losses in non-regulated

221 AER, Rule change request, Part B, 29 September 2011, p. 59.

222 AER, Rule change request, Part B, 29 September 2011, p. 60.

223 Ergon Energy, Consultation Paper submission, 8 December 2011, p. 14, ENERGEX, Consultation Paper submission, 8 December 2011, p. 4.

224 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 98.

activities.[225] Ausgrid comments that alternative control services should be excluded from the uses of assets which would result in additional compensation to consumers.[226]

Submissions also suggest that there should be guiding principles for the exercise of the AER's discretion. These might include: any adjustment should be subject to a positive commercial outcome having been achieved; the level of compensation should take into account the risks involved; incentives should be maintained for NSPs to apply assets to non-regulated activities; and regulatory oversight should only be imposed where benefits exceed costs.[227]

### 4.7.5 Analysis

The Commission considers that consumers should receive some benefit when assets used to supply regulated services are shared with other services, as consumers are funding the assets and bearing the risk if they are under-utilised. Using electricity assets for additional purposes should reduce the (average) costs of providing electricity services since the fixed costs are spread over a larger number of consumers. This promotes efficient use of electricity services with respect to price. This could be seen as a form of innovation, which NSPs should be encouraged to achieve, where it does not have a negative effect on the service provided to electricity consumers. The regulatory framework needs to find the appropriate level of sharing of benefits so NSPs are rewarded for cost-cutting and consumers benefit through lower prices.

These principles apply equally in respect of transmission assets and distribution assets, even though it may be less common in transmission than distribution for regulated assets to be used for unregulated services. On this basis the Commission is of the view that any changes that apply in respect of electricity distribution should also apply to electricity transmission.

In many respects, the changes proposed by the AER at a high level resemble removing the shared assets from the RAB, as UE and MG point out.[228] This is not unlike other rules that relate to the roll forward of the RAB from one regulatory control period to the next. In particular, the effect is similar to the provisions of NER clauses S6.2.1(e)(7) of Chapter 6 (in respect of distribution) and S6A.2.3 of Chapter 6A (in respect of transmission), except that the asset does not actually leave the RAB.

The Commission's initial view is that shared assets should be dealt with by way of a mechanism which is flexible, and that principles should be developed to provide guidance on when compensation should be permitted, and how much that compensation should be.

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225 UE and MG, Consultation Paper submission, 8 December 2011, p. 18.

226 Ausgrid, Consultation Paper submission, 8 December 2011, p. 33.

227 ENA, Consultation Paper submission, 8 December 2011, p. 39; Ausgrid, Consultation Paper submission, 8 December 2011, p. 33.

228 UE and MG, Consultation Paper submission, 8 December 2011, p. 18.

In terms of the appropriate mechanism to be used to provide for the sharing, this should be at the AER's discretion and could include, among other things, adjustment to the revenue requirement or price control mechanism. Changes to the NER, such as the possibility of a revenue decrement under NER clause 6.4.3(a), may be necessary to ensure the AER has the necessary power to implement its chosen mechanism. The relevant mechanism to be applied should be set out in the framework and approach paper.

In terms of the guiding principles, the Commission accepts that any sharing of benefits should ensure incentives remain for NSPs to seek alternate uses for network assets, and that regulatory oversight should only be applied when the benefits exceed the costs. While the extent of sharing should also take account of some of the risks involved to the NSP, the NSP cannot be insulated from all risks, and the requirement of sharing should not be subject to a positive commercial outcome having been achieved.

The Commission notes Ausgrid's comment that alternative control services should be excluded from the uses of assets which would result in additional compensation to consumers. This appears to be appropriate. The Commission invites submissions on the types of uses of an asset which should not result in additional compensation to consumers.

### 4.7.6 Initial position

The Commission accepts that consumers should receive some benefit when assets used to supply regulated services are shared with other services.

The Commission now seeks input on the best form of a solution. The solution will include guiding principles, and may also involve changes to the NER to enable an appropriate mechanism.

### 4.7.7 Issues for further comment

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|---|---|
| **Question 17** | **Should the concept of compensation for consumers for use of shared assets be applied to transmission, as well as distribution?** |
| **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 allocating compensation arising from sharing assets between regulated and unregulated services?** |

# 5 Rate of return frameworks

**Summary**

- The NER and NGR allow for NSPs and gas service providers to earn a return on their investments. There is a different framework for determining the rate of return in electricity transmission, electricity distribution and gas.
- The AER proposes that these three sectors move to a single framework which most closely aligns to electricity transmission. Under this framework, there would be periodic reviews of the rate of return parameters, which are then fixed and apply to revenue/pricing determinations for NSPs under the NER and access arrangement decisions for gas service providers under the NGR.
- The Commission's view is that the current rules in this area are not satisfactory. In particular, the framework to estimate the rate of return for electricity transmission businesses does not provide sufficient flexibility to adapt to changing circumstances. The frameworks for gas and electricity distribution are preferable.
- The Commission's initial preference is for a single framework to be used across all three sectors (not necessarily the same parameter values), but will consider different frameworks for electricity and gas service providers.
- The framework(s) will continue to be based on estimating the WACC for a benchmark efficient firm. A benchmark efficient firm could be different for different electricity transmission, distribution and gas service providers
- The Commission's preliminary view is that the rate of return framework should not prescribe the methodology or values for parameters, but rather provide guiding principles.
- The Commission's view is that the rules should require the regulator to consider using ranges for certain parameter values and linkages between different WACC parameters when it applies them.

## 5.1 Objective

A key component to determining revenues/prices for NSPs and gas service providers is the rate of return on capital. The building block approach applies a rate of return to the RAB or projected capital base (as the case may be) to determine the return on capital allowance to be included in the revenue requirement in each year of a NSP's regulatory determination or access arrangement.[229]

229 See NER clauses 6A.6.2(a) and 6.5.2(a). See also NGR rule 76(a).

In the regulatory context, the return on capital is generally determined using the weighted average cost of capital (WACC). The WACC is an estimate of the return on capital that investors might reasonably expect as compensation for having their capital at risk. The WACC estimates a particular business's cost of capital by estimating the required return on debt and equity for a benchmark efficient firm and weighting these estimated returns by the total value of debt and equity held or expected to be held by a benchmark efficient firm with similar characteristics and risk profile. The consideration of the WACC generally incorporates consideration of the effects of taxation[230]and the dividend imputation system applicable in Australia.[231]

Given the capital intensive nature of electricity and gas networks, the return on capital component of their regulated revenues can account for anywhere between approximately 50 to 70 per cent of their annual aggregate revenue requirement (see Appendix C for some examples of the proportion of revenue components of NSPs and gas service providers). Therefore, relatively small changes to the value of the overall rate of return can have a significant impact on the total revenue requirements of NSPs and gas service providers, and ultimately, consumer prices.

The NEO and NGO contemplate that NSPs and gas service providers undertake efficient investments and ensure prices reflect the efficient cost of providing services to their consumers. In practice, this means that the regulator should set revenue/prices that reflect the efficient cost of providing a particular regulated service.

The principal objective of a WACC estimate is to ensure that a NSP or a gas service provider receives a return on capital allowance that reflects efficient financing costs to ensure appropriate funds can be attracted while minimising the cost to consumers of the investment (assuming the decision to invest is prudent). Therefore, the NEO and NGO is more likely to be met if the NER/NGR allow for the formulation of a rate of return that reflects the efficient financing costs of NSPs and gas service providers.

## 5.2 Current rules

The current frameworks for determining the rate of return for electricity transmission, electricity distribution and gas service providers differ in terms of the level of prescription and flexibility. They are set out in Chapter 6A of the NER for electricity transmission, Chapter 6 of NER for electricity distribution, and in rule 87 of the NGR

230 The corporate tax rate is relevant because the investors' return on capital must be after corporate tax. For this reason, the regulated NSP's revenue requirement is "grossed up" in relation to corporate tax. It is common to adopt the statutory corporate tax rate of 30%. The vanilla WACC formula does not include any adjustment for dividend imputation credits – this comes through the cash flows.

231 Australia has operated in a dividend imputation tax system since 1987 where dividends paid by Australian companies out of profits that have been taxed in Australia have tax franking credits attached to them. Consideration of the dividend imputation credits has an important effect on the grossing up for corporate tax through the "gamma" value. The value of gamma is usually dealt with as part of the WACC considerations, at least in part due to the inter-relationship between the WACC and gamma parameters.

for gas service providers. The following sections provide a summary of each framework.

### 5.2.1 Electricity transmission

The Chapter 6A framework for determining the rate of return for electricity transmission was developed by the AEMC.[232]

Under Chapter 6A of the NER, the rate of return for TNSPs is the cost of capital as measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by a TNSP (the benchmark efficient firm).[233] This means that the rate of return does not provide any compensation for diversifiable risks of TNSPs (ie those that are not related to broad market movements but are specific to a particular firm) and requires the AER to consider returns that would be expected for a benchmark TNSP.

The rules further prescribe the cost of capital to be calculated as a nominal post-tax WACC, with the return of equity determined using the Capital Asset Pricing Model (CAPM).[234] The return on debt is required to be determined as the sum of the risk free rate plus the debt risk premium (DRP), which is defined as the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate with a defined credit rating and term to maturity equal to that of the nominal risk free rate.[235]

The NER locked in some initial parameter values and codified certain methodologies for determining some of the parameter values.[236] However, the rules require the AER to undertake reviews of the methodologies and values for a number of parameters (including credit rating level for DRP) that make up the WACC every five years, starting from 31 March 2009.[237]

A key feature of this WACC approach is that the parameter values determined during the AER's WACC reviews must then be applied to each subsequent determination. There is no ability to depart from the parameter values determined during the review until the next WACC review in five years, except for the value of the nominal risk free

232 AEMC, *Economic Regulation of Transmission Services*, Rule Determination, 16 November 2006.

233 NER clause 6A.6.2(b).

234 Ibid.

235 NER clauses 6A.6.2(b) and 6A.6.2(e).

236 For example, the equity beta of 1.0, the MRP of 6.0% and gearing ratio of 0.6 were explicitly set initially (NER clause 6A.6.2(b)). Parameters methodologies that are codified include the meaning of the nominal risk free rate (NER, clause 6A.6.2(c)) and the meaning of DRP (NER clause 6A.6.2(e)).

237 NER clause 6A.6.2(g). The NER refers to a number of WACC parameters that the AER can review, including the value of the parameter, or the methodology used to determine the value as well as the maturity period and bond rates for determining the nominal risk free rate and the credit rating levels for the DRP. For ease of expression, reference in this chapter to WACC parameters refers to either the value or the methodology used to estimate the value, unless the context requires otherwise.

rate and the DRP which are dependent on being measured using latest observed market data at the time of the determination.

In the Chapter 6A rule determination, the AEMC expressed the view that the rules should enable the AER to review the parameters periodically and make appropriate changes to take account of changes in financial market conditions and developments in finance theory and practice.[238]

The AEMC also included a number of principles and criteria that the AER must have regard to in varying the parameters in its reviews. They include:

- the need for the rate of return to be forward looking and commensurate with prevailing conditions in the market for funds and the risk involved in providing the prescribed transmission services;
- the need for the cost of debt to reflect the current cost of borrowing for comparable debt; and
- the need for the credit ratings levels, values or methodologies should be based on the concept of a benchmark efficient TNSP.[239]

Furthermore, the rules require that where the parameter cannot be determined with certainty, the AER must have regard to the need to achieve an outcome consistent with the NEO and the need for persuasive evidence before adopting a different value, method or credit rating.[240] This test was included so that the AER could satisfy itself that current evidence on the WACC parameters are sufficient to justify a change from the parameter values adopted in the most recent WACC review.[241]

In developing this framework, the AEMC noted, among other things, that there was a high degree of stability in the WACC parameter values adopted by the state regulators in the years leading up to the AEMC's review.[242]

### 5.2.2 Electricity distribution

The Chapter 6 framework for determining the rate of return for electricity distribution was made by the SCER (at the time the MCE) and commenced on 1 January 2008.

The framework in Chapter 6 of the NER was modelled on the Chapter 6A provisions. The cost of capital for DNSPs is to be measured by the return required by investors in a commercial enterprise with a similar nature and degree of non-diversifiable risk as that faced by a DNSP (the benchmark efficient firm).[243] As noted in section 5.2.1 above, this

238 AEMC, *Economic Regulation of Transmission Services*, Rule Determination, 16 November 2006, p. 82.

239 NER clauses 6A.6.2(j)(1)-(3).

240 NER clause 6A.6.2(j)(4)(i) -(ii).

241 AEMC, *Economic Regulation of Transmission Services*, Rule Determination, 16 November 2006, p. 83.

242 Id., p. 82.

243 NER clause 6.5.2(b).

means that the rate of return does not provide any compensation for diversifiable risks of DNSPs and requires the AER to consider returns that would be expected for a benchmark DNSP. The parameters that make up the WACC are also identical to the Chapter 6A requirements.[244]

Consistent with the Chapter 6A framework, there is also a requirement for periodic reviews of parameters that are required for the WACC estimation. In this case, however, the AER can undertake reviews more frequently than every five years.[245] The output of the WACC review is referred to as the Statement of Regulatory Intent (SORI).[246]

The MCE introduced another important difference in the Chapter 6 framework that is absent from Chapter 6A of the NER. The MCE amended the framework to allow the AER to consider persuasive evidence to depart from the SORI determined parameter value, method or credit rating if there was persuasive evidence at the time of making an individual distribution determination.[247]

Also, the MCE decided that decisions by the AER on whether or not persuasive evidence has been established in relation to a particular parameter value, method or credit rating as part of a distribution determination would be subject to merits review. The merits review process in the NEL was introduced at the same time as Chapter 6 commenced.

### 5.2.3 Gas

The gas framework, like the Chapter 6 electricity distribution framework, was made by the MCE and implemented in 2008.[248]

The requirements for determining the return on capital allowance is largely a replication of the predecessor provisions from the *National Third Party Access Code for Natural Gas Pipeline Systems* (the National Gas Code).[249]

The NGR includes three requirements for the estimation of the rate of return for gas service providers.

The first requirement is that the rate of return on capital is to be commensurate with prevailing conditions in the market for funds and the risk involved in providing reference services.[250]

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244 Ibid.

245 NER clause 6.5.4(b).

246 NER clause 6.5.4(f).

247 NER clause 6.5.4(g) and see further MCE SCO, *Response to stakeholder comments on the Exposure Draft of the National Electricity Rules for distribution revenue and pricing*, 1 August 2007, pp. 15-16.

248 See for example, MCE SCO, *Response to issues raised in submissions on the National Gas Rules*, 14 May 2007.

249 See sections 8.30 and 8.31 of the National Third Party Access Code for Natural Gas Pipeline Systems available at http://www.coderegistrar.sa.gov.au.

The second requirement is that in determining the rate of return on capital, two assumptions should be made. The assumptions are that the relevant service provider:

(i) meets benchmark levels of efficiency; and

(ii) uses a financing structure that meets benchmark standards as to gearing and other financial parameters for a going concern and reflects in other respects best practice.[251]

The third and final requirement is that in determining the rate of return on capital, a well-accepted approach that incorporates the cost of equity and debt, such as the WACC, is to be used, and a well-accepted financial model, such as the CAPM, is to be used.[252]

A common feature of the rate of return framework under the NGR and Chapter 6 of the NER is that the return on capital allowance determined in an access arrangement by the AER is subject to merits review. This means that gas service providers can challenge either individual components of the AER's decision on parameters or the entire return on capital allowance.

## 5.3 Rule change requests

This section provides a high level summary of the rule change requests from the AER regarding the rate of return frameworks under the NER and the NGR. The issue of cost of debt is discussed in the next Chapter of this directions paper.

### 5.3.1 AER proposal

**Issues identified**

The AER has raised a number of issues with the current provisions governing the determinations of an appropriate rate of return in the NER and the NGR.

The AER claims that the electricity distribution and gas frameworks have been problematic.[253] The AER claims that both of these frameworks have required the continual assessment of similar arguments and evidence at each regulatory determination and access arrangement process; either in determining the parameter values themselves, or in the case of electricity distribution, determining whether there is persuasive evidence to depart from the conclusions of the WACC review.[254] The AER's contention is that this process creates a high administrative burden, where DNSPs attempt to cherry pick certain parameters and engage in arguments even where evidence is not persuasive, or to repeat and repackage data and theoretical arguments

250 NGR rule 87(1).

251 NGR rules 87(2)(a)(i) and 87(2)(a)(ii).

252 NGR rule 87(2)(b).

253 AER, Rule change request, Part A, 29 September 2011, p. 16.

at each distribution determination.[255] The AER also argues that the ability to depart from the SORI for specific parameters precludes the AER and the Tribunal from assessing the overall reasonableness of the rate of return decision.[256]

The AER has also argued that the ability for the DNSPs to challenge its determinations of WACC parameters has resulted in merit reviews involving a "spurious" level of precision in the context of some parameters.[257]

The AER has raised similar issues in relation to the rate of return framework in the NGR.[258]

The AER also states that the persuasive evidence test in Chapter 6 and 6A is problematic to interpret, and a potentially unnecessary threshold that inappropriately restricts its ability to determine an efficient benchmark rate of return.[259] Furthermore, the AER claims that the current requirement for persuasive evidence in the WACC reviews is unnecessary as it affords undue weight to previous outcomes rather than permitting the regulator to set appropriate methods or values for WACC parameters considering all relevant factors, including previous decisions.[260]

The AER also contends that there is no justification for the divergence in the process for the determination of WACC as between the electricity transmission, electricity distribution and gas sectors.[261] The AER states that the WACC is predominantly based on market and sector wide benchmarks and is, thus, independent of business/industry specific considerations.[262] The AER further states that an unintended consequence of having different WACC frameworks is that they could produce different benchmark parameter values that, in the AER's view, should otherwise be the same across industries.[263] The AER states that different benchmark parameter values are likely to result in investment distortions between sectors.[264]

**Solution proposed**

The AER has proposed rule changes to establish a single process for determining WACC parameters for electricity transmission, electricity distribution and gas. The proposal includes the following features:

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254 Ibid.

255 Id., p. 68.

256 Id., p. 69.

257 Id., p. 65.

258 AER Rule change request, Gas Rules, 29 September 2011, pp. 2-4.

259 AER, Rule change request, Part A and B, 29 September 2011, p. 71.

260 Id., pp. 16, 72-73.

261 AER, Rule change request, Part B, 29 September 2011, pp. 65, 67; AER Rule change request, Gas Rules, 29 September 2011, p 2.

262 AER, Rule change request, Part A and B, 29 September 2011, p. 65.

263 Id., p. 67

264 Ibid.

- the AER would undertake a single WACC review, with the methodologies and parameter values decided in that review, to apply to all three sectors. The outcome of the AER's single WACC review would be applied to all subsequent determinations for NSPs and access arrangements for gas service providers via a "Statement on the Cost of Capital" (SOCC); and

- the timing of these reviews would be determined by the AER, but reviews would be held at least every five years, as is currently the case for Chapter 6 of the NER.

In addition, there would be no persuasive evidence test applying. In its absence, the AER has proposed that it would still have regard to the previously adopted parameters as part of its WACC considerations.[265]

There would be no opportunity for any merits review and consequently, no need for any persuasive evidence test in relation to a specific determination on any WACC parameter.

The AER's proposed gas rule change is for the NGR to mirror the provisions with respect to the development, publication and application of the outcomes of the WACC review as proposed by the AER in its NER rule change request.[266] These reviews would be undertaken outside of the access arrangement decisions made under the NGR.

Under the AER's rule change request, the rate of return that gas service providers include in their access arrangement proposals would need to be consistent with the most recent SOCC published at the end of each WACC review.[267]

As part of its proposal to have a single WACC framework, the AER has also proposed changes to the NGR that would prescribe a nominal post-tax WACC approach to make it consistent with the NER approach, and remove the current flexibility in the NGR by requiring that the cost of equity be calculated using the CAPM (similar to the current provisions in the NER).[268]

## 5.4 Submissions

NSPs and gas service providers are strongly opposed to the AER's proposals. In their view, the problems that the AER asserts in relation to the frameworks under Chapter 6 of the NER and the NGR are not supported by evidence.[269]

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265 Id., p. 72.

266 AER Rule change request, Gas Rules, 29 September 2011, pp. 2-4.

267 Id., p. 5.

268 Id., pp. 7, 11.

269 See for example: APA Group, Consultation Paper submission, 8 December 2011, p. 6; ATCO Gas Australia, Consultation Paper submission, 11 December 2011, p. 7; Aurora Energy, Consultation Paper submission, 15 December 2011, p. 11; Ausgrid, Consultation Paper submission, 8 December 2011, pp. 20-21; DBP, Consultation Paper submission, 9 December 2011, p. 3; ENA, Consultation Paper submission, 8 December 2011, p. 2; Envestra, Consultation Paper submission, 8 December

NSPs argue that merits review is an important aspect of the current rules that provides a "safety valve" to correct for any material errors that may be made by the AER. They also assert that the current level of flexibility in Chapter 6 of the NER to depart from outcomes of the WACC reviews was an important avenue to cope with dramatic changes in financial market circumstances, as evidenced from the global financial crisis (GFC) and its effects in the debt and equity markets.[270]

Gas service providers similarly point out that the flexible nature for determining the rate of return under the NGR is an equally important way to deal with volatile market conditions that can dramatically influence the required return on capital to attract the necessary investment in their sector.[271]

Submissions from some NSPs and gas service providers also note that there are legitimate reasons for the rate of return frameworks to be flexible enough to recognise differences between the electricity and gas sectors, and the difference between assets in the gas sector, in determining appropriate rates of return.[272] Consequently, their position is that the AER's proposal to apply a single framework in determining the rate of return for electricity and gas sectors would not necessarily be appropriate.[273]

Submissions from a number of NSPs and industry associations such as Grid Australia and the ENA, put forward a case that the electricity transmission framework has turned out to be the most problematic. They suggest that TNSPs have found the "lock-in" nature of the WACC reviews to be too inflexible to deal with GFC-type events as well as incapable of responding to any errors found in the AER's WACC methodology and parameter value decisions. Consequently, Grid Australia, the ENA, the Financial Investor Group as well as other NSPs propose that the Chapter 6A framework for determining the WACC should be aligned with the existing Chapter 6 approach by introducing the persuasive evidence test to allow departure at any

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2011, p. 3; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp 25-26; Financial Investor Group, Consultation Paper submission, 8 December 2011, p. 2; Grid Australia, Consultation Paper submission, 8 December 2011, p. 2; Jemena, Consultation Paper submission, 8 December 2011, pp. 78-79; and UE and MG, Consultation Paper submission, 8 December 2011, pp. 19-20.

270 See for example: Ausgrid, Consultation Paper submission, 8 December 2011, p. 21; ENA, Consultation Paper submission, 8 December 2011, pp. 49-51; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 122; Financial Investor Group, Consultation Paper submission, 8 December 2011, p. 36; Grid Australia, Consultation Paper submission, 8 December 2011, p. 63; and UE and MG, Consultation Paper submission, 8 December 2011, p. 20.

271 APA Group, Consultation Paper submission, 8 December 2011, pp. 13-15; ATCO Gas Australia, Consultation Paper submission, 11 December 2011, p. 6; Envestra, Consultation Paper submission, 8 December 2011, p. 5; and UE and MG, Consultation Paper submission, 8 December 2011, p. 20

272 See for example: Ausgrid, Consultation Paper submission, 8 December 2011, p. 20; APIA, Consultation Paper submission, 8 December 2011, pp. 15-17 and 53-70; DBP, Consultation Paper submission, 9 December 2011, p. 4; and ENA, Consultation Paper submission, 8 December 2011, pp. 44 and 53.

273 Ibid.

revenue determination if evidence suggests that the AER should depart from the parameter values determined at a WACC review.[274]

Submissions from small consumer groups generally support the AER's rule change request.[275] The Victorian DPI also supports the AER's proposal.[276]

The WA Office of Energy expressed some concern with the AER's proposals in respect of the NGR. It is of the view that there is no evidence that a five year WACC review will provide greater certainty to deal with market volatility as claimed by the AER.[277]It is also opposed to the prescription of post-tax WACC and CAPM in the NGR, citing the need for the ERA to continue to apply a flexible approach such as that currently afforded by the NGR.[278] On the other hand, the ERA is supportive of the AER's proposal, but suggests that the relevant regulator should have discretion as to whether and when to undertake the periodic WACC reviews.[279] The ERA also supports the post-tax WACC approach and CAPM prescription, noting that its existing pre-tax WACC approach has become problematic in recent years.[280]

## 5.5 Summary of consultant's views

In order to assist the Commission in evaluating the current rate of return approaches under the NER and NGR, the AEMC has asked Professor Stephen Gray and Dr Jason Hall from SFG to provide expert advice on:

- identifying and commenting on the key attributes of a WACC estimation framework that is likely to achieve the NEO and NGO; and
- evaluation of the AER's proposed rule changes having regard to the NEO and NGO.

In summary, SFG concludes that the better, more accurate and more robust a WACC estimate is, the more consistent it will be with the NEO and the NGO. SFG is of the view that the current rules for determining the rate of return for NSPs and gas service providers all have features that prevent the highest-quality WACC estimates from being achieved. SFG has stated that high-quality WACC estimates will come from an approach that:

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274 ENA, Consultation Paper submission, 8 December 2011, p. 52; Grid Australia, Consultation Paper submission, 8 December 2011, p. 63; and Financial Investor Group, Consultation Paper submission, 8 December 2011, p. 38.

275 ACOSS, Consultation Paper submission, 8 December 2011, p. 2; Consumer Action Law Centre, Consultation Paper submission, 9 December 2011, p. 1; COTA Australia, Consultation Paper submission, 8 December 2011, p. 3; CUAC, Consultation Paper submission, 23 December 2011, p. 2; QUT CCCL, Consultation Paper submission, 8 December 2011, p. 2.

276 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 10.

277 WA Office of Energy, Consultation Paper submission, 8 December 2011, p. 1.

278 Id., p. 2.

279 ERA, Consultation Paper submission, 6 December 2011, p. 4.

280 Ibid.

- reflects current market circumstances;
- utilises all of the relevant data;
- considers all relevant estimation methods;
- ensures internal consistency;
- is open and transparent;
- has been subject to scrutiny; and
- can be cross-checked for reasonableness.[281]

In evaluating the AER's rule change requests, SFG concludes that they would not produce the best possible regulatory estimates of WACC, and in some respects are likely to produce estimates that are inferior and more prone to error than the estimates that are produced under the current rules.[282] In SFG's view, more preferred rule changes than those proposed by the AER may produce higher-quality WACC estimates and should be considered further by the AEMC as well as stakeholders in their submissions to this rule change process.

The Commission has also asked SFG for advice on whether there is a case for a common WACC framework across the electricity and gas sectors covered by the NER and the NGR. In its report, SFG has drawn a distinction between having a common WACC framework and having common parameter values applying across the sectors. SFG states that the WACC framework should be defined as being limited to:

(a) the definition of WACC that is to be applied (eg post-tax nominal vs. pre-tax real); and

(b) the approaches that can be adopted to estimate the required return on equity (eg CAPM vs. other approaches).[283]

SFG believes that there are several reasons to support the use of a common WACC framework across all three sectors. It states that:

- adopting a different framework across industries has the potential to lead to allocative inefficiencies. For example, different approaches across industries could lead to materially different allowed returns even though the risk profiles of the industries were not materially different. This, in turn, would lead to relative over-investment in the high-return industry and under-investment in the low-return industry;

281 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, pp. 16-17.

282 Id., p. 2.

283 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, pp. 25, 57-67.

- there is no compelling reason to adopt different frameworks across the three industries. For example, there is no argument that the CAPM works well for NSPs, but not for gas service providers, or that a post-tax nominal WACC is more appropriate for one class of NSPs whereas a pre-tax real approach is more appropriate for others. The differences between the frameworks that currently apply to the three industries under the current NER and NGR appear to be more to do with historical accident than a conscious choice to accommodate any perceived need for different frameworks; and

- although not the determinative consideration, a common approach across industries is likely to result in some administrative cost savings for the AER and for businesses with interests across industries. Having a common approach may also assist in focussing analysis and debate.[284]

With respect to the case for adopting common parameter values as opposed to a common framework, SFG states that a number of WACC parameters are market-wide parameters that do not vary across industries. These parameters include the risk-free rate, the market risk premium (MRP), gamma, and corporate tax rate parameters.[285] According to SFG, parameter values that can vary by firm or industry include equity beta, gearing levels and credit ratings. However, SFG states that estimation of parameter value differences between gas and electricity or between distribution and transmission sectors are impossible to detect.[286]

SFG has also considered a number of specific WACC-related issues raised by the rule change requests. SFG recommends that:

- if a common WACC definition is to be applied, the default should be a vanilla post-tax nominal definition that is currently prescribed under the NER. Alternative proposals would have to justify why that alternative is likely to result in a higher-quality WACC estimate;

- consideration should be given to allowing regulators to consider models other than the CAPM when estimating the required return on equity for all NSPs and gas service providers;

- consideration should be given to allowing regulators the flexibility to adopt WACC parameter values that they believe to be most appropriate for the particular NSP or gas service provider in question rather than being constrained to adopt the same parameter value for all types of NSPs and gas service providers;

- consideration should be given to allowing regulators the flexibility to adopt the parameter value that they believe to be most appropriate at the time of each determination/access arrangement; and

284 Id., p. 26.

285 Id., p. 27.

286 Id., p. 28.

- consideration should be given to allowing a merits review of WACC parameter values for all NSPs and gas service providers on the basis that more scrutiny of WACC parameter values are likely to produce higher-quality WACC estimates.[287]

## 5.6 Analysis

This section provides an overview of the Commission's preliminary analysis of the effectiveness of the existing WACC frameworks in the NER and the NGR as well other key issues raised by the AER's rule change requests.

### 5.6.1 Effectiveness of Chapter 6A framework

When the AEMC made the Chapter 6A rules, the overriding objective was the need to ensure investment certainty and stability for TNSPs. The Chapter 6A rules sought to achieve this objective by providing a framework that delivered a stable and predictable WACC. The AEMC noted that:

> "Providing short term stability regarding the WACC determination reduces an important source of potential variability in regulatory decision making thereby providing a more certain and predictable environment for investment and financing decision making.[288]"

In making these rules, the AEMC recognised at the time that a trade-off is ultimately necessary to provide investment certainty, stability and the need to ensure methodologies for estimating parameter values, and the values themselves, can evolve. However the AEMC also noted that the methodology and parameter values for the WACC are matters that the regulator must be able to review periodically and to exercise discretion and judgement as to whether there is a case for change.[289]

In its report, SFG highlights a number of reasons why the current Chapter 6A framework of the NER is not delivering outcomes consistent with the NEO.[290]SFG states that the fact that WACC parameter values are fixed for a long period results in a WACC that would be applied to TNSPs that may not reflect current market conditions. For example, where a set of WACC parameter values are fixed during a period of financial stability and growth, and if a period of financial crisis occurs during the subsequent five years, the regulatory WACC will no longer be commensurate with current market conditions.[291]

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287 Id., pp. 26-29, 32-33.

288 AEMC, *Economic Regulation of Transmission Services*, Rule Determination, 16 November 2006, p. 82.

289 Ibid.

290 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, pp. 19-22.

291 Id., p. 19.

This issue was evident during the onset of the GFC and its effect both during and since the AER's 2009 WACC review. While this issue could potentially be overcome by conducting a fresh WACC review, that process is currently precluded from being undertaken in Chapter 6A of the NER.

In addition, Chapter 6A of the NER does not allow for WACC parameter values to be adjusted for any errors that are potentially made when estimating the parameter values at the time of each WACC review. This is because the WACC reviews for TNSPs are not subject to merits review under the NEL. The issues created by lack of access to merits review to adjust parameters is evident from the recent Tribunal decision in relation to the gamma parameter in the context of the Chapter 6 WACC framework for DNSPs.[292]

In the merits review appeals sought by DNSPs, the Tribunal has determined that the AER erred in estimating the value of the gamma parameter value in the first electricity distribution determination after the WACC review in 2009. According to the Tribunal, the most appropriate estimate for the gamma value is 0.25, rather than the 0.65 value that the AER applied to DNSPs based on the conclusions from its 2009 WACC review.

Since that Tribunal decision, the AER has decided to depart from the SORI to adjust the gamma value to 0.25 in subsequent electricity distribution and gas access arrangement decisions. The AER is able to make such a change because the Chapter 6 framework and the NGR framework (discussed further below) permits consideration of whether changes should be made to any particular parameter. By contrast, under the current Chapter 6A framework, the AER cannot consider applying the revised gamma value as determined by the Tribunal to any TSNP revenue determinations made after the 2009 WACC review until the next scheduled WACC review. This means that, even if the AER considers that the gamma value determined by the Tribunal in the context of DNSPs is the correct value that should be applied for all NSPs, the AER must continue to apply the gamma value that it had fixed in the 2009 WACC review.

Furthermore, the WACC parameter values established under Chapter 6A of the NER cannot be adjusted to reflect changes in market data availability. Under the Chapter 6A framework, some WACC parameters do not have values locked in at the time of the WACC review, but rather have an estimation method or data source prescribed for use in subsequent determinations (the methodology). For example, this is the case with the risk free rate parameter.[293] In its report, SFG suggests that it is possible that a prescribed data source ceases publishing the relevant data or that a new and possibly even superior data source may become available between WACC reviews.[294] SFG

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292 See Application by Energex Limited (Gamma) (No 5) [2011] ACompT 9 (12 May 2011) and Application by Energex Limited (No 2) [2010] ACompT 7 (13 October 2010).

293 See AER, *Final Decision - Review of the WACC parameters - Electricity transmission and distribution network service providers*, May 2009, pp. iii, xiii, 20-21, 75-77.

294 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, p. 20.

notes that the Chapter 6A framework of the NER does not easily accommodate changes in the estimation methods in such circumstances.[295]

A WACC estimate that is not commensurate with market conditions may make it difficult for the TNSPs to attract the necessary investment capital or could lead to customers paying too much for the service they receive from the TNSP. Both of these outcomes have the potential to be to the detriment of the long term interests of consumers.

In light of these issues, the Commission is of the view that the Chapter 6A framework of the NER has some drawbacks in delivering optimal WACC estimates for TNSPs. The AER's view that the Chapter 6A framework of the NER is working well and ought to form the basis of a single unified WACC framework does not appear to be supported by the evidence to date. The Commission considers that inflexibility of a WACC framework to adjust parameter values should be carefully weighed against consumer interests that TNSPs be provided with a reasonable rate of return that reflects market conditions that are more attuned to allow them to raise the investment capital needed to maintain and upgrade their networks.

Furthermore, the framework should also be flexible enough to allow consideration of new information or data sources that will improve the accuracy of the WACC estimation. The Commission also considers that a rate of return framework that does not allow for merits reviews of WACC parameters can create distortions in the rate of return of TNSPs by not allowing adjustments to be made for any errors, incorrect exercise of discretion and unreasonable decisions made by the AER.

However, the Commission's concerns about the current operation of the Chapter 6A framework do not mean that the Commission considers that any form of periodic WACC review would necessarily fail to deliver appropriate WACC estimates. The Commission welcomes submissions on whether some WACC parameter values are more stable than others, and sufficiently stable to be fixed with a high degree of confidence for a number of years into the future. The Commission also invites submissions on whether it would 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.

### 5.6.2 Effectiveness of Chapter 6 framework

A significant amount of debate on the WACC framework under Chapter 6 of the NER has focussed around three principal issues which, to an extent, are linked.

The first issue is whether the problems identified by the AER in its rule change request are demonstrated by the evidence, particularly in relation to the AER's assertion that for many parameters, the current framework in Chapter 6 of the NER provides for the AER and DNSPs to be in "continual WACC review" mode where considerable

295 Ibid.

resources are spent during each determination process re-examining issues that have been previously considered.

The second issue is about the role of merits review. This issue is primarily focussed around the AER's view that DNSPs engage in "cherry-picking" of certain WACC parameters for merits review. The AER's main contention is that such a selective WACC parameter appeals process detracts from the AER's (and the Tribunal's) ability to adequately consider the resulting overall rate of return for NSPs.

The third issue is focussed around the interpretation of the persuasive evidence test. The AER considers that this test is problematic, in that it is difficult to interpret, and its meaning is uncertain. The AER places emphasis, in support of its view, on differing opinions between the AER and stakeholders in the 2009 WACC review regarding the proper interpretation and application of the test.

The AER's motivation for changing the WACC framework is primarily predicated on these three issues. Each of these issues is discussed in more detail below.

**What is causing the "continual WACC review"?**

Contrary to the AER's assertions, submissions from stakeholders such as Grid Australia, ENA, Jemena, ETSA, CitiPower and Powercor and the Financial Investor Group have strongly argued that DNSPs and the AER have not been in continual WACC review mode. For instance, the ENA and Grid Australia submissions noted that in eight determinations conducted since the 2009 SORI, only two parameters dealt with in the SORI (which, importantly, does not include the DRP) have been subject to any form of review. These included:

- in relation to the gamma value, where the Tribunal held that the AER had erred in determining the value. These appeals were a response to the widespread dissatisfaction with the AER's treatment of gamma during the 2009 WACC review and the absence of a merits review option from that decision; and
- in relation to the MRP, where some DNSPs proposed a higher value in light of new analysis as to the impact of the GFC that was not considered in the SORI by the AER. The AER did not accept this new analysis and all subsequent DNSP proposals have adopted the SORI value of 6.5 per cent.[296]

On the issue of DNSPs re-packaging WACC arguments to the AER, the Commission notes SFG's view that if the arguments have appeared in a previous determination, but the data has been updated, there may be some information content in the new data that should be examined to ensure that the WACC estimate reflects the most up to date information.[297] Additionally, SFG observes that it would only be rational for a DNSP

296 Grid Australia, Consultation Paper submission, 8 December 2011, pp. 60-61, and ENA, Consultation Paper submission, 8 December 2011, pp. 42-43.

297 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, p. 31.

to re-package an argument if it felt that it had not been satisfactorily addressed by the AER and that either the AER or Tribunal may now decide the issue differently.[298]

The Commission accepts that the AER must dedicate a significant amount of resources to undertake the required five-yearly WACC reviews. In addition to this, under the Chapter 6 framework of the NER, the AER must then dedicate resources to consider material put before it by DNSPs as part of their proposals during the regulatory determination process.

While this process inevitably takes time and incurs costs, as noted by SFG, any administrative costs involved in evaluating WACC submissions from DNSPs are likely to be outweighed by the impact that even very small changes in WACC parameter values can have on required revenues for the regulated assets of the DNSP.[299] As illustrated in Appendix C, the return on capital component of the revenue requirements of NSPs forms a significant part of their regulated revenues.

Modelling results from the AER on the sensitivity of WACC parameter values to revenues illustrates the reason why DNSPs may be motivated to argue for departure from the SORI. Table 5.1 below shows the incremental impact of various WACC parameter values and their impact on the revenues of a select number of DNSPs revenues based on the AER's final decisions.

**Table 5.1 Illustrative sensitivity of certain WACC parameters to revenues of DNSPs**

| Impact of each WACC value on total unsmoothed revenue (%) | | | | | |
|---|---|---|---|---|---|
| | *Change in gamma by +/-0.05* | *Change in beta by+/-0.05* | *Change in market risk premium by +/-0.5%* | *Change in debt risk premium by +/-0.5%* | *Change in risk free rate by +/-0.5%* |
| DNSP 1 | 0.6% | 1.0% | 1.3% | 1.8% | 3.4% |
| DNSP 2 | 0.5% | 0.7% | 1.1% | 1.4% | 2.5% |
| DNSP 3 | 0.6% | 1.2% | 1.5% | 2.1% | 3.9% |
| DNSP 4 | 0.9% | 0.8% | 0.9% | 1.3% | 2.5% |

Source: Modelling results provided by the AER.

As shown in Table 5.1 above, some WACC parameter values have a much greater impact on revenues than others. For instance, the DNSP revenues are extremely sensitive to relatively small changes in the value of the risk free rate and the DRP.

Given the sensitivity of the WACC parameter values, it is reasonably conceivable that if the WACC review results in parameter values that are below the efficient financing costs that a DNSP requires at the time of its distribution determination, then the

298 Ibid.

299 Id., p. 30.

DNSP's main motivation would be to ensure that the rate of return the AER ultimately decides upon is *at least* sufficient to ensure that it can attract the funds in the financial markets to undertake investments in its network over its regulatory period.

Having considered the evidence submitted by the AER, NSPs and advice from SFG, the Commission does not consider that the DNSPs are being unnecessarily advantaged from having the ability to engage with the AER on WACC issues at the time of their determinations. Clearly, DNSPs have an inherent incentive to argue for the highest possible WACC estimate. Having said that, there may be circumstances that justify the AER considering whether it should depart from a previously adopted parameter value where the departure would result in a better WACC estimate.

More generally, the Commission considers that WACC parameter values can change and evolve over time as evidence and data change. The Chapter 6 WACC framework provides a mechanism for the values to evolve in a way that the Chapter 6A framework does not.

The Commission also notes that the Chapter 6 framework of the NER does not just envisage DNSPs alone being able to argue for departure from the WACC parameter values in the SORI. The AER has the necessary discretion to symmetrically consider whether or not to depart from a previously adopted parameter value at the time of the regulatory determinations. Indeed, the AER has exercised such discretion in its recent draft determination for Aurora Energy to adjust the MRP.[300] The AER rejected Aurora's proposed MRP value of 6.5 per cent because it considers that there is persuasive evidence justifying a departure from the SORI value which is based on the 2009 WACC review. The AER has adopted a MRP value of 6 per cent for the purposes of calculating Aurora Energy's WACC.[301]

By contrast, under the Chapter 6A rules, the AER is unable to adopt the revised MRP value based on its own evidence for Powerlink's draft transmission determination for 2012-13 to 2016-17 issued at the same time as the Aurora Energy's draft distribution determination.[302] The AER has had to adopt the 2009 WACC review MRP value of 6.5 per cent even though it states that "[T]he MRP is common to all assets in the economy and is not specific to an individual asset or business".[303]

It seems incongruous that the AER considers that it has persuasive evidence to justify departure on the MRP in one case, but cannot use that evidence to change the MRP value in another case even though it considers that parameter value not to be specific to any individual NSP. Clearly, the AER has no choice in the case of Powerlink's determination, and this outcome is the result of the rigidity of the rules in Chapter 6A. On the one hand, the Chapter 6 rules have allowed the AER to respond to changing market circumstances at the time of the distribution determination of Aurora Energy. On the other, under the Chapter 6A rules mean that the AER must overlook market

300 AER, *Draft Distribution Determination Aurora Energy 2012-13 to 2016-17*, November 2011.

301 Id., p. 210.

302 AER, *Draft Decision - Powerlink Transmission Determination 2012-13 to 2016-17*, November 2011.

303 Id., p. 220.

evidence and apply an out-of-date parameter value to Powerlink's revenue determination.

The Commission is of the view that, if the ability to consider the appropriateness of outcomes from a WACC review at the time of making the distribution determinations was removed, then the Chapter 6 framework of the NER would suffer from the same deficiencies of inflexibility in responding to changing market circumstances that the Chapter 6A framework appears to suffer from.

The Commission considers that, if there is likely to be good reason to adjust one or more WACC parameter estimates from that determined in a WACC review, preventing such adjustments would be inconsistent with the goal of obtaining the best possible WACC estimate to reflect the efficient financing costs of DNSPs. Some possible reasons for adjusting parameters may include the availability of new data or estimation techniques, changes to market conditions, and the correction of errors. As noted above, such adjustments are already being made since the AER's 2009 WACC review, for example in relation to the gamma parameter (due to the Tribunal's finding of error) and the MRP (the AER has changed the estimate it employs on the basis that it considers there to have been a change in market circumstances).

**Cherry-picking of parameters in merits review**

NSPs have strongly argued against the AER's contention that they "cherry pick" for appeal those WACC parameters which they consider unfavourable to them. The NSPs have contended that the reason for the numerous appeals to the Tribunal on WACC has resulted from two factors.

The first is that the WACC review itself is not subject to merits review. This means that any errors in either methodology by the AER or selection of a value or data based on out-dated evidence relied on by the AER in the WACC review cannot be scrutinised. The second factor is that each DNSP must then wait until its individual distribution determination to seek the Tribunal's intervention to consider the matter. A clear example of this was the case of the gamma parameter appeals by DNSPs.[304]

NSPs have also suggested that it is difficult to understand the AER's assertion that the merits review by the Tribunal has involved the pursuit of a "spurious" level of precision. Submissions from NSPs noted that the AER has conceded errors in its estimation of WACC in a number of appeals, and that the Tribunal has found errors by the AER in determining WACC parameter values in many reviews of WACC decisions brought to date.[305]

304 Application by ETSA Utilities [2010] ACompT 5 (13 October 2010); Application by Energex Limited (No 2) [2010] ACompT 7 (13 October 2010) and Application by Energex Limited (Distribution Ratio (Gamma)) (No 3) [2010] ACompT 9 (24 December 2010).

305 For example, ETSA, CitiPower and Powercor in its submission state that the Tribunal's reviews of WACC decisions to date disclose the real potential for AER errors in WACC decision making including in particular in WACC reviews and the potential significance of those errors: ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 113-114.

The Commission recognises that the Tribunal's finding of an error by the AER in estimating the gamma value for DNSPs and current concerns with the cost of debt element of the WACC (in particular, the scope of evidence that can be used to inform the DRP estimate which is discussed further in Chapter 6), has contributed significantly to the number of appeals that have occurred. The AER has been seeking to apply a methodology for estimating the DRP for DNSPs that the AER has found difficult to apply given the lack of available information. Given these difficulties with the rules and the sensitivity of WACC parameter values on DNSPs' revenues, it is perhaps less surprising that there have been a significant number of appeals.

If the AER's contention is that the focus of the Tribunal's review on just one parameter in an appeal fails to consider the inter-relationships between other WACC parameters that were considered by the AER in its decision, then it may be the case that the merits review process itself would need to be reviewed. On the other hand, if the AER's contention is that the current rules prohibit it from making offsets to a particular parameter where it has been found to have too low an estimate against another that the AER considers to be generous, then it raises the question why doesn't the AER simply produce the best estimates for all WACC parameters?

The estimates of WACC parameters are subject to uncertainty.[306] To date, the AER has taken the approach of a preferred value for each parameter in the overall calculation of the WACC. One way to explicitly recognise the uncertainty in estimating particular parameters would be for the regulator to use ranges.[307] If ranges are adopted for some parameter values, then it may be possible to estimate a range for the resulting WACC from which the regulator could choose a preferred estimate. The Commission notes that IPART takes such an approach to estimating a number of market dependent WACC parameters for the businesses it regulates in NSW.[308]

However, any regulatory judgement to adopt a range for parameter values also needs to recognise that there may be inter-relationships between some parameters, so that variation of one parameter value may necessitate adjustment of another parameter value. While the Commission recognises that estimating some WACC parameter values requires a certain level of regulatory judgement in weighing up various sources of information and evidence, it is incumbent upon the regulator to identify and explain clearly where and when it has made the necessary trade-offs against precision in its estimates of parameter values and the overall reasonableness of its WACC estimates. To facilitate this, there may be some scope to amend the rules to clarify that the decision on the overall WACC estimate involves decisions about some uncertain and inter-related parameters, so a decision on each parameter value cannot be considered or reviewed in isolation.

306 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, p. 14.

307 This view was also expressed by Michael Cunningham in discussing a number of related judicial decisions: Michael Cunningham, Consultation Paper submission, 8 December 2011, pp. 6-8.

308 See IPART, *IPART's weighted average cost of capital* , Final Decision, April 2010.

The Commission welcomes submissions on the usefulness of amending the rules to better recognise the uncertainty and inter-relationships of various WACC parameters.

**Application of the persuasive evidence threshold**

The AER has highlighted that there is ambiguity and differing views in interpreting the precise meaning of persuasive evidence. The AER further considers that the persuasive evidence test may inappropriately restrict its ability to determine an efficient benchmark rate of return.[309]

The AER states that the persuasive evidence test has the potential (depending on how the relevant provisions are interpreted) for undue weight to be placed on consistency with previous regulatory outcomes at the expense of setting parameters that are appropriate or otherwise in accordance with the interests of stakeholders.[310] It further observes that the removal of the persuasive evidence test to apply at the time of each WACC review will provide more flexibility for the AER to deal with changing market circumstances.

While stakeholders, especially the NSPs, have made considerable comments in relation to the removal of the persuasive evidence threshold test from the NER, their main concern stems from the fact that the AER's proposal would effectively remove their access to merits review on WACC parameters in Chapter 6 of the NER. The applicability of the persuasive evidence threshold at the time of their distribution determination is what provides the DNSPs with access to merits review.

The Commission is interested in understanding further stakeholders' views on how the outcomes with the "persuasive evidence" test might differ from the NGR rate of return framework. In particular, does the "persuasive evidence" test make it less likely that values of WACC parameters will be updated as quickly as under the NGR framework? This question seeks further comment from stakeholders on whether the AER's view that the test risks placing too much weight on consistency with previous parameters is shown through the outcomes for specific parameters.

**Summary of the analysis on the effectiveness of Chapter 6**

Notwithstanding the questions raised above about the interpretation of the "persuasive evidence" threshold, it is clear that as compared to the provisions of Chapter 6A of the NER, Chapter 6 is a more flexible framework, and provides greater scope to react to changes in evidence about parameter values.

Given the original values in the SORI are based on the same framework as the WACC review for Chapter 6A, the concerns about the framework for estimating the WACC parameters under Chapter 6A are also present for Chapter 6. While the Commission has concerns about how some of the parameter values are estimated under Chapter 6, given the flexibility in the approach, the Commission will consider further whether the features of Chapter 6 – a WACC review with scope to update values – may in some

309 AER, Rule change request, Part B, 29 September 2011, p. 71.

310 Id., p. 73.

form be an option to consider for any rule changes the Commission proposes in its draft rule determination.

### 5.6.3 Effectiveness of the gas approach

The main reason for the AER proposing changes to the rate of return framework under the NGR is to provide for a single WACC framework that is consistent with its proposals under the NER. In support of its proposal, it has cited the same reasons as for its NER proposal.

Gas service providers are strongly opposed to any changes to the rate of return framework under the NGR. Their principal argument is that the AER has not made a case that the current framework does not meet the NGO. There has been very limited experience in the application of the NGR provisions that can be used to provide evidence on the effectiveness of the NGR framework. Gas service providers have also highlighted the fact the NGR has only been in operation since 2008 and only about half the gas service providers have had experience under the current NGR framework.

While it is true that the NGR has only operated for limited time, the rate of return framework in the current rules essentially replicates the framework that was in place for many years under the National Gas Code.[311] This means that the NGR framework is not necessarily a new framework for gas service providers.

The Commission's initial view is that there are a number of positive features of the NGR framework. The flexible nature of requiring the rate of return to be determined at the time of each access arrangement decision means that the AER or ERA can effectively have regard to current market circumstances. Indeed, this is precisely what is required from the criteria in rule 87(1) of the NGR that requires the rate of return to be commensurate with prevailing conditions in the market for funds and the risk involved in providing the reference service.

In addition, the NGR framework arguably allows the AER and the ERA to take into account and consider all of the latest available information on estimation techniques, data and methodologies at the time of their decisions. However, evidence suggests that many WACC issues pertinent in the electricity framework have also been an issue in the gas framework. The merits review appeals by gas service providers to date clearly illustrate that issues such as the MRP, gamma and the DRP have been equally as problematic as in the case of the AER's regulatory determinations under the Chapter 6 framework of the NER.

Notwithstanding the flexible nature of the NGR framework, the decision-making criteria on various parameters for determining the rate of return on capital provides for very open-ended debate on what approach would provide the best estimate. For example, there is no guidance in the NGR as to what factors should be considered in determining how the cost of equity is to be estimated, other than to specify a "well accepted approach". While flexibility in the framework appears to provide a number of

311 MCE SCO, *Response to issues raised in submissions on the National Gas Rules*, 14 May 2007, p. 10.

advantages, the Commission is interested to understand whether stakeholders see any value in, or are concerned about, the lack of guidance on how the AER and ERA will approach determinations under the gas framework. Could such guidance provide any benefits without a significant loss of flexibility?

It also appears that in applying the gas framework, the AER and the ERA often make use of the approaches they apply to the electricity businesses they regulate. The Commission welcomes submissions on whether the approach of the regulators in practice means that it is difficult to evaluate the gas framework on a stand-alone basis because its application is being significantly influenced by the approach adopted for the electricity sector.

**Nominal post-tax WACC and CAPM**

Gas service providers were also against the AER's proposal to align the NGR framework with the NER's nominal post-tax WACC definition and use of the CAPM to estimate the cost of equity component.

The NGR does not prescribe whether the rate of return for gas service providers should be determined on pre-or-post tax basis. However, the AER has adopted the nominal post-tax approach to date under the NGR.

Furthermore, while the NER mandates that the required return on equity must be estimated using the CAPM, the NGR only requires that a "well-accepted financial model such as the CAPM" must be used.[312]

As part of recent access arrangement processes, a number of gas service providers have submitted that other models such as the Fama-French three-factor model, the Black CAPM, and the dividend growth model should also be considered. It has been argued that these alternative models can provide estimates of the required return on equity or as a cross-check on the CAPM estimate. To date, the AER (and the ERA) have not accepted that any of the alternative models is well-accepted and have not used any other model. A discussion on alternative approaches to the CAPM is provided in SFG's report.[313]

On the issue of the nominal post-tax approach, the APA Group in its submission states that the AER's preferred position is not shared by the ERA, which maintains a pre-tax approach, applying the corporate tax rate.[314] The APA Group suggests that it was this diversity of approach that led the MCE to allow a diversity of approaches in the NGR at its inception.[315]

312 See NGR, rule 87(2)(b).

313 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, Appendix 1.

314 APA Group, Consultation Paper submission, 8 December 2011, p. 27.

315 Ibid.

By contrast, the ERA in its submission states that its use of the pre-tax CAPM has become problematic.[316] The ERA states that it is considering amending its approach to adopt the post-tax CAPM approach. It notes that prescribing a nominal post-tax approach within the CAPM could:

- address concerns regarding any over-compensation arising from the pre-tax approach;
- reduce the distorting effect in the potential for gas service providers to 'cherry pick' unfavourable elements in the WACC determination;
- generally reduce the administrative cost associated with reviewing the rate of return provisions; and
- allow for a consistent approach, thereby informing the relativity of returns among different regimes.[317]

It is evident that there are divergent views about whether the nominal-post tax WACC definition and the exclusive use of the CAPM is the best way to determine an accurate WACC estimate. If the rules prescribe a particular way, then the regulator would have no option in considering alternative approaches. This is currently the case with the NER frameworks where the AER is required to apply the nominal post-tax WACC definition and use the CAPM.

The flexibility afforded in the NGR on these issues, while not resulting in any changes in the AER's approach to date, has at least allowed alternatives to be considered in light of evolving theoretical and empirical evidence. If evidence continues to mount, a point may be reached where alternative models may be warranted if it is more likely to produce WACC estimates that are of a much better quality than is achieved through the current models. This is evident from the ERA's views on its approach to date. Prescribing a particular model in the rules may unnecessarily restrict the regulator from considering evidence or information that would support using alternatives.

The value in having the flexibility to consider alternative models is also made by SFG. For example, SFG states that if the goal is to produce the highest-quality estimate of the required return on equity – the value that most closely corresponds with what equity investors would actually require from an investment in the benchmark firm – the question is whether restricting the estimation approach to the CAPM only is more likely to produce the highest-quality WACC estimate.[318] More relevantly, SFG concludes that excluding other approaches from consideration is unlikely to assist in achieving the best WACC estimate.[319]

316 ERA, Consultation Paper submission, 6 December 2011, p. 4.

317 Ibid.

318 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, p. 27.

319 Ibid.

The Commission agrees that it is difficult to make the case that allowing the regulator to consider more information would systematically result in a poorer WACC estimate. It is important to recognise that the acceptance and use of financial models evolves over time with experience and research (both theoretical and empirical). The Commission's preliminary thinking on this issue is that a more flexible approach may be more appropriate and considers that the existing approach in the NGR has merit. In general, excluding any relevant information from consideration will lower the quality of any WACC estimate. However, as discussed in the previous section, it may be necessary to provide some guidance to focus the debate on models that would provide the best estimate, rather than resulting in open-ended debates on approaches that may or may not be considered "well accepted".

The Commission intends to do more work on whether such flexibility in the use of pre- and post-tax WACC and alternatives to the CAPM should be considered by the AER for the electricity NSPs under the NER.

### 5.6.4 Is there a case for a common rate of return framework?

At the heart of the AER's proposal for a single rate of return framework across the NER and the NGR is its view that many of the WACC parameters are industry-wide benchmarks and having different frameworks may result in benchmarks that are not consistent, and ultimately, create a divergence in the allowed rates of return.

Stakeholders have not raised a concern about the concept within the NER and NGR of using a benchmark efficient firm as the basis for setting the rate of return. The Commission is not proposing to revisit this issue when considering this rule change proposal. However, the Commission would like to be clear about its understanding and interpretation of the concept of the benchmark firm within the NER and NGR.[320]

The Commission considers that the rate of return frameworks in the NER and NGR should allow the regulator to determine a benchmark efficient firm for the purposes of estimating the rate of return based on the specific characteristics of the NSP or gas service provider that affect the degree of non-diversifiable risk of the network company. Potential examples of factors that may affect the extent of non-diversifiable risk include the demand growth of the NSP/gas service provider, the nature of the customer base, the type of contracts entered into with customers and the ability of the regulated firm to control labour market conditions. This means that the framework would need to allow a regulator to choose a different benchmark efficient firm for different types of electricity transmission, electricity distribution or gas service providers. Whether the regulator in practice chooses different benchmark efficient firms is a matter for the regulator to determine having regard to the relevant evidence, including market evidence from businesses which are considered to be close comparators to the benchmark NSP/gas service provider.

The Commission recognises that even if the regulator considered that it might be appropriate to have a different benchmark efficient firm for different NSPs or gas

320 NER clauses 6.5.2(b), 6.5.4(e)(3), 6A.6.2(b), 6A.6.2(j)(3), and NGR rule 87(2)(a)(i)-(ii).

service providers, the empirical evidence may not allow for sufficient precision in the estimates of some or all WACC parameters to calculate a different WACC for different benchmark efficient firms. Again, it is a matter for the regulator to determine whether, and if so how, evidence of differences between electricity or gas networks would be reflected in different WACC for the relevant benchmark efficient NSP or gas service provider.

In this context, the Commission notes that SFG highlights an important distinction to be made between having a common rate of return framework and having common parameter values applying across electricity transmission, electricity distribution and gas sectors.[321] The Commission considers that having a common rate of return framework does not imply that the same parameter values should always be adopted for each and every NSP or gas service provider. As discussed above, it is preferable to allow the regulator to assess the values of parameter estimates from the perspective of what it considers to be an appropriate benchmark efficient NSP or gas service provider in the circumstances.

Earlier in the Chapter, the potential for the regulator to develop ranges for parameters values was discussed. The use of ranges could also help to allow the regulator to consider different benchmarks.

Given the issues that have been identified in the Chapter 6 and 6A frameworks and the arguments made by SFG, the Commission sees some merit in the idea of a common WACC framework within which the regulator would determine appropriate parameter values from the perspective of an appropriate benchmark efficient NSP or gas service provider in the circumstances. In addition, the Commission notes that submissions from NSPs also seem to favour establishing a common framework, at least for the TNSPs and DNSPs under the NER.

While different frameworks for electricity and gas may be appropriate, the potential consequences of having different frameworks must be considered carefully.

The Commission believes that there is a need to re-think the attributes of a rate of return framework than can produce rates of return that reflect efficient financing costs of NSPs and gas service providers. The Commission's preliminary thinking is that a good rate of return framework is one that:

- is based around estimating a rate of return for benchmark efficient firms;
- allows methodologies for parameters to be driven by principles and reflect current best practice;
- allows flexibility to deal with changing market conditions;
- recognises the inter-relationships between some parameter values; and

321 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, p. 25.

- creates a framework of accountability for both the regulator and the NSP/gas service provider in determining an appropriate rate of return.

The Commission welcomes submissions on whether the rate of return for NSPs and gas service providers can be enhanced by adopting a common framework across the three sectors. The Commission is also interested in views on which current WACC approach best meets the key attributes noted above.

## 5.7 Initial position

The Commission's initial view is that the rate of return framework under Chapter 6A for TNSPs appears to be no longer appropriate. Even though this framework provides stability and certainty by locking in a number of WACC parameter values for five years, this may potentially come at the expense of a decline in the resulting appropriateness of the required rate of return for TNSPs over time.

Since the development of the Chapter 6A framework by the AEMC in 2006, experience suggests that parameter values and views on methodologies for estimating the parameters can and do change and evolve as new evidence or data emerges. A good example of this has been the developments in financial markets since 2008 and the Tribunal's findings on the gamma parameter value. This framework lacks any mechanism to allow the AER to consider whether the parameter values or methods determined for all TNSPs as part of its fixed periodic WACC review remain appropriate at the time of an individual TNSP's revenue determination, even though it may be of the view that there is evidence to suggest a change.

The Chapter 6 framework for DNSPs appears to provide more flexibility compared with the Chapter 6A framework for responding to changes in circumstances, whether it be new evidence to require reconsideration of a particular parameter value, or instability in financial markets.

However, the combined approach in Chapter 6 of requiring the AER to apply WACC parameter methodologies and values established well in advance of their application and then requiring reconsideration at the time of individual revenue/pricing determinations of DNSPs has resulted in significant on-going debate between the DNSPs and the AER about the degree to which there is sufficient evidence to depart from the outcomes of the WACC review. The Commission's view is that DNSPs have an inherent incentive to present evidence to secure the most generous rate of return from the regulator, but it also accepts that there may be genuine circumstances to justify the AER considering whether it should depart from a previously adopted parameter value or methodology where the departure would result in a better overall rate of return. It may be difficult in these circumstances for the AER to determine if there is a genuine need to depart from a particular parameter value or method.

The frequency of appeals for merits review does not necessarily imply that DNSPs are cherry-picking unfavourable parameters. The merits review appears to result more from the fact that DNSPs cannot seek a review of the outcomes of periodic WACC reviews that they consider erroneous until their individual revenue/pricing

determinations. Furthermore, the Commission observes that many of the appeals on the DRP issue have resulted from the fact that the AER has been seeking to apply a methodology that can accommodate changes in market conditions, although, as discussed in the next Chapter, the AER has had some difficulty in settling on an acceptable methodology given the lack of available information.

It is unclear to the Commission whether the persuasive evidence test has been difficult to apply in practice. While the AER has claimed that the test is difficult to interpret, it has recently accepted that there is a sufficient amount of evidence to depart from a previously determined parameter value, such as the MRP. Before the Commission draws any firm views on this issue, it would like to better understand how the outcomes with the persuasive evidence test in the NER might differ from the discretion provided in the NGR framework to consider alternative approaches.

It is also important to recognise that any departure from a parameter may have implications for other parameters. There may be some scope be some scope to clarify that the decision on the overall rate of return estimate involves decisions about a range of inter-related WACC parameters, so a decision on each parameter value cannot be considered in isolation.

In any event, the Commission is more concerned about the effect of removing NSPs' and gas service providers' access to merits review. 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. Ultimately, it is in consumers' interests that NSPs be provided with a rate of return that reflects efficient financing costs required to maintain investment in electricity and gas networks.

In relation to the NGR, the Commission recognises that there are some benefits of flexibility in the current NGR rate of return framework. The Commission considers that it is relevant to consider whether the differences in approach to determining the rate of return on investment are justifiable. The interaction between the different approaches in the NER and the NGR has also led to some concerns that the flexibility afforded to the AER in the NGR framework to consider alternative approaches to post-tax CAPM is not being exercised, even though there may be theoretical and empirical evidence to suggest that a better estimate of the rate of return could be made with alternative models. The Commission would like to better understand how the NGR framework has worked alongside the prescribed approach to post-tax nominal WACC and the use of CAPM in the NER.

The Commission's initial preference is for a single framework to be used across all three sectors, but is open to consider different frameworks for electricity and gas service providers. The framework(s) should ideally continue to be based on estimating the WACC for a benchmark efficient firm, although the benchmark efficient firm could be different for different electricity transmission, distribution and gas service providers.

In addition to considering the NGR and Chapter 6 frameworks further, the Commission will be exploring alternative options for determining WACC based around flexible approaches, while considering the scope to provide some certainty through the use of guidance on methodologies.

## 5.8 Issues for further comment

To assist the Commission in the next stage of its assessment, stakeholders are invited to respond to specific questions as noted below.

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| **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 its proposed methodologies on certain WACC parameters as opposed undertaking periodic WACC reviews that locks in parameter values for future revenue/pricing determinations?** |
| **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?** |
| **Question 23** | **How do the outcomes with 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?** |
| **Question 24** | **How has the rate of return framework under the NGR worked alongside the NER frameworks?** |
| **Question 25** | **Are there any concerns about the 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?** |

| | |
|---|---|
| **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 the 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?** |
| **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?** |

# 6 Cost of debt

**Summary**

- An important component of rate of return decisions is the cost of debt allowance.
- The AER and the EURCC consider that the current approach to the cost of debt in the NER is not optimal.
- The AER proposes that the cost of debt methodology should be left to its discretion in the periodic review of rate of return parameters.
- The EURCC proposes a new benchmark cost of debt for privately-owned NSPs, and that the actual cost of debt should be used for government-owned NSPs.
- The Commission shares the view that the current approach to the cost of debt in the NER is problematic, though it does not agree there should be a different approach depending on whether a NSP is government-owned or privately-owned.
- The Commission's initial view is that the cost of debt methodology should not be detailed in the rules, but should be determined by the regulator.
- The Commission is seeking further comments and analysis on whether the EUCC's proposal to use the trailing average approach to estimate the cost of debt should be an option available to the regulator under the rules.

## 6.1 Objective

The WACC weights the separate costs of equity and debt capital according to the gearing ratio, in order to calculate the average expected return investors of all forms of capital require to facilitate the provision of these funds. The cost of debt can be described as the expected cost to a regulated business for raising debt capital and is therefore an important element in determining the regulated rates of return for NSPs and gas service providers. The importance of ensuring that the WACC reflects efficient financing costs is discussed in section 5.1 of the previous Chapter.

The NER refers to the cost of debt component of the WACC as "return on debt".[322] This discussion paper adopts the more commonly used expression of "cost of debt", unless the context requires otherwise.

322 See NER clauses 6A.6.2(b) and 6.5.2(b).

## 6.2 Current rules

Chapters 6 and 6A of the NER define, for electricity distribution and transmission respectively, the return on debt (cost of debt) to be the nominal risk free rate plus the DRP.[323] No such definition exists in the NGR.[324]

The NER provisions define the nominal risk free rate as the rate determined for a regulatory control period by the AER on a moving average basis from the annualised yield on Commonwealth Government bonds with a maturity of 10 years.[325] The length of the averaging period is not a prescribed component of the NER risk-free rate method, although the AER must not unreasonably withhold its agreement of an averaging period proposed by the NSP.[326]

The DRP for a regulatory control period is defined as the margin between the annualised nominal risk free rate and the observed annualised Australian benchmark corporate bond rate for corporate bonds which have a maturity equal to that used to derive the nominal risk free rate.[327] The only difference between Chapters 6 and 6A is that, in the definition of the DRP, Chapter 6A specifies the initial use of a credit rating of BBB+ from Standard and Poors for the Australian benchmark corporate bonds. Chapter 6, on the other hand, does not specify the credit rating or the credit rating agency.[328]

The specification and the term of the nominal risk free rate and the benchmark credit rating levels for the DRP estimate can be reviewed by the AER under Chapters 6 and 6A of the NER.

In its 2009 WACC review, the AER decided to retain the 10 year term assumption and the use of the yield on 10 year Commonwealth Government bonds as the risk-free rate proxy on the basis that there was no persuasive evidence to justify departure.[329] Consequently, the AER's approach to determining the nominal risk free rate remained consistent with 10 year term assumption and the use of the yield on 10 year Commonwealth Government bonds as was initially specified in Chapters 6 and 6A of the NER.[330]

Given that the NER require that the term-to-maturity to derive the DRP must match the maturity of the nominal risk free rate, the AER's decision to adopt a 10 year term

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323 NER clauses 6.5.2(b) and 6A.6.2(b).

324 While the NGR does not mention the DRP, it does however specify at a broad level that the rate of return on capital for gas service providers is to be commensurate with prevailing conditions in the market for funds and the risk involved in providing reference services: see NGR rule 87(1).

325 NER clauses 6.5.2(c) and 6A.6.2(c).

326 NER clauses 6.5.2(c)(2)(i)-(iv) and 6A.6.2(c)(2)(i)-(iv).

327 NER clauses 6.5.2(e) and 6A.6.2(e).

328 Ibid.

329 AER, *Review of the WACC parameters - Final decision - Electricity transmission and distribution network service providers*, May 2009, p. 172.

330 NER clauses 6.5.2(c) and 6A.6.2(c).

assumption for the nominal risk free rate meant that it only had to consider issues related to the selection of a credit rating for a benchmark efficient NSP in its 2009 review. After considering the evidence available at the time, the AER concluded that the BBB+ credit rating as initially deemed in Chapter 6A remained an appropriate credit rating level for benchmark efficient TNSPs and DNSPs.[331] This means that the approach required to be taken by the AER for the estimation of the cost of debt involves determining the DRP for benchmark Australian corporate bonds with a credit rating of BBB+ and a term-to-maturity of 10 years.

## 6.3 Rule change requests

This section summarises the AER's rule change requests relating to the cost of debt component of the WACC under Chapters 6 and 6A of the NER and the NGR. It also provides a summary of the EURCC's rule change request on cost of debt under Chapters 6 and 6A of the NER.

### 6.3.1 AER proposal

**Issues identified**

The AER claims that the current definition of the DRP significantly constrains its ability to set an efficient cost of debt. In particular, the AER states that the reference to a benchmark bond with a particular term to maturity, credit rating and domicile of the issuer bears little resemblance to the financing practices of NSPs and other behaviours of NSPs to minimise their cost of debt.[332] The AER states that information from market reports shows that the cost of recently issued debt for NSPs and gas service providers has been around 2.5 per cent above the risk free rate, while the AER has approved DRP values of between 3 and 4 per cent above the risk free rate in electricity determinations and gas access arrangement decisions since 2010.[333]

The AER also states that while the NER explicitly defines the benchmark corporate bond rate, it is unclear whether the maturity, credit rating and domicile are an exhaustive list of factors, prompting significant debate including through merits review processes.[334] A further issue raised by the AER is that it has encountered problems in applying the specified DRP benchmark due to a lack of sufficient market data, hindered by the impact of the GFC on bond markets. The AER states that finding information on bonds that match or even approximate the 10 year term and BBB+ credit rating (as determined in the 2009 WACC review) is extremely difficult under current market circumstances.[335]

331 AER, *Review of the WACC parameters - Final decision - Electricity transmission and distribution network service providers*, May 2009, p. 391.

332 AER, Rule change request, Part B, 29 September 2011, p. 77.

333 Id., pp.79-80.

334 Ibid.

335 Id., p. 78.

The AER states that the approach adopted in gas access arrangement decisions to setting the cost of debt under the NGR has also mirrored the formulation and parameters under the current rules (including the DRP). Accordingly, similar issues with respect to the benchmark for measuring the DRP under the NER have been considered by the AER in recent gas access arrangement decisions.[336]

**Solution proposed**

The AER proposes to remove the definition of the DRP for determining the cost of debt from Chapters 6 and 6A. Instead, the AER would set a methodology for calculating the DRP as part the WACC that would occur at least every five years.[337] The AER's rule change proposal would also remove the definition of the nominal risk free rate from Chapters 6 and 6A of the NER.

The AER claims that removing the definition of the DRP from the NER would allow the AER to better determine an efficient cost of debt. The AER states that once a definition and methodology is set out in the SOCC, it will provide clarity and certainty for stakeholders during the life of that statement.[338] The AER states that it will provide a much better outcome than the current situation where it is continually drawn into debating the DRP and the associated methodology/data at every electricity distribution determination and gas access arrangement decision.[339]

### 6.3.2 EURCC proposal

#### Issues identified

The EURCC's proposal also focuses on the cost of debt component of the WACC under Chapters 6 and 6A of the NER.[340]

The EURCC's rule change request states that the benchmark debt term and credit rating determined by the AER in its 2009 WACC review, being 10 year BBB+ rated debt issued by the Australian corporate sector with similar characteristics as the NSPs, are inappropriate benchmarks as there are no corporate bonds issued in Australia that meet this requirement of tenure and credit risk. The EURCC states that, as a result, the AER has had no option other than to develop extrapolation estimates based on short-term bonds and bonds with different credit ratings.[341]

The EURCC claims that as a result of these flaws, the allowed cost of debt in the WACC estimates has been higher than the actual cost of debt, which has resulted in

336 Id., p. 77.

337 Id., pp. 80-81.

338 Id., p. 81.

339 Ibid.

340 EURCC, Rule change request, 17 October 2011.

341 Id., p. 24.

excessive profits to NSPs' shareholders, higher prices for electricity consumers and perverse incentives for over-investment in the electricity networks.

The EURCC argues that the NEO requires that the cost of debt, whether for government or privately-owned NSPs, should reflect what it refers to as the "actual" cost of debt. It further argues that NSPs should, in principle, not profit on the debt they raise.[342]

**Solution proposed**

The EURCC's proposal is to amend Chapters 6 and 6A of the NER to require the AER to determine the cost of debt in a way that the EURCC consider more closely reflects the actual cost of debt of NSPs. It is proposing to require the cost of debt for government-owned NSPs to be determined on a different basis to privately-owned NSPs, as follows:

- *for government-owned NSPs* - the cost of debt allowance for each year during a regulatory period would be based on the average yield to maturity (for the previous calendar year) of all bonds issued by the respective state government, which have between three and seven years to maturity;[343] and
- *for privately-owned NSPs* - the cost of debt allowance for each year of a regulatory period would be established through a five year rolling average of the Fair Market Value (FMV) yield of five year investment grade (broad BBB and broad A rated) corporate debt issued in Australia.[344]

For government-owned NSPs, the EURCC considers that it would be inconsistent to allow them to charge users for a cost of debt as though they were privately owned. It states that such an approach – which currently applies – contravenes the national competition policy principles agreed to by the Council of Australian Governments in 1995 (amended in 2007) and is also unsupported by economic theory.[345]

The EURCC believes that for privately-owned NSPs, the use of an index that reflects FMV estimates of the yield to maturity on investment grade corporate debt issued in Australia would provide appropriate incentives for them to minimise their debt costs.[346]

In addition to proposing rule changes that define the cost of debt so as to give effect to this proposal, the EURCC also proposes amendments to:

- remove the maturity and credit rating levels used in estimating the DRP from the scope of AER's WACC reviews under the current rules; and

342 Id., p. 5.

343 Id., p. 41.

344 Id., p. 42.

345 Id., pp. 30-31.

346 Id., p. 8.

- remove from the considerations to which the AER must have regard in conducting WACC reviews that provide for a forward-looking rate of return commensurate with prevailing conditions in the market for funds and a cost of debt that reflects current borrowing costs, as these considerations are inconsistent with the backward-looking approach to the estimation of the cost of debt proposed by the EURCC.[347]

## 6.4 Submissions

Despite their reservations about the AER's rule change proposal, NSPs and gas service providers agree with the AER that elements of the DRP are difficult to establish due to difficulties encountered in financial markets post-GFC and market data issues that have become apparent due to the current nature of the Australian corporate bond market.[348] However, in contrast to the AER's solution, there was only support for considering incremental changes to ensure flexibility, but with the intent of ensuring increasing investment certainty by giving NSPs a benchmark cost of debt allowance. NSPs did not support the AER's proposal to remove the definitions of DRP from the NER.

Submissions from small consumer groups appeared to support the AER's rule change request in a general sense.[349]

In relation to the EURCC's rule change, NSPs argue that much of the evidence on the extent of the problem the EURCC has identified is flawed. A number of submissions state that the EURCC's analysis of "excessive profits" earned by NSPs is incorrect and based on superficial assumptions that do not reflect the reality of how NSPs raise or manage their debt in the market. In particular, government-owned NSPs such as Ausgrid, Endeavour Energy, ENERGEX and Ergon Energy state that, contrary to the EURCC's assertion, they actively manage their debt in conjunction with their respective treasury agencies and pay government-imposed competitive neutrality fees on their debt to ensure they do not have any material advantages against the private sector in raising debt in the markets.[350]

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347 Id., pp. 49-53.

348 Ausgrid, Consultation Paper submission, 8 December 2011, pp. 21-22; ENA, Consultation Paper submission, 8 December 2011, pp. 51-52 and 54-55.; Essential Energy, Consultation Paper submission, 14 December 2011, p. 7; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 32; Financial Investor Group, Consultation Paper submission, 8 December 2011, pp. 42-45; Grid Australia, Consultation Paper submission, 8 December 2011, pp. 70-72; UE and MG, Consultation Paper submission, 8 December 2011, p. 20.

349 ACOSS, Consultation Paper submission, 8 December 2011, p. 2; Consumer Action Law Centre, Consultation Paper submission, 9 December 2011, p. 1; COTA Australia, Consultation Paper submission, 8 December 2011, p. 3; CUAC, Consultation Paper submission, 23 December 2011, p. 2; QUT CCCL, Consultation Paper submission, 8 December 2011, p. 2.

350 Ausgrid, Consultation Paper submission, 8 December 2011, p. 23; Endeavour Energy, Consultation Paper submission, 8 December 2011, p. 6; ENERGEX, Consultation Paper submission, 8 December 2011, p. 4; Ergon Energy, Consultation Paper submission, 8 December 2011, p. 12.

Regarding the evidence put forward by EURCC and the AER on the difference between the allowed cost of debt and what has been called "actual" cost of debt for some NSPs, a number of submissions argue that the difference between the regulated rate of return and their cost of debt simply reflects refinancing risk.[351] The NSPs argue that the lower yield to maturity available on short-term debt, relative to long-term debt, is more than offset by an increase in the required return to equity holders to compensate for the risk of being unable to refinance debt for the next regulatory period, and this has not been considered by the EURCC. NSPs have also argued that their preference, and their consistent practice prior to the GFC, is to raise long-term debt (because the higher interest rates are more than offset by the reduction in refinancing risk) but that they are simply unable to raise the required amount of long-term debt in the current market circumstances.

While there is considerable disagreement with the EURCC's proposal to determine the cost of debt for government-owned NSPs differently from privately-owned NSPs, there is support from NSPs for further consideration of setting the cost of debt allowance to reflect the cost of a benchmark entity taking into account the cost of embedded debt.[352]

The Queensland Treasury Corporation (QTC) states that the EURCC's proposition that actual cost of debt of NSPs is materially lower than the AER's allowance is incorrect. The QTC states that the fact that NSPs have recently raised shorter-term debt does not account for the higher systematic risk borne by equity providers due to increased refinancing risk when NSPs are unable to raise longer-term funding.[353]

According to the NSW Treasury, the profit margins quoted by the EURCC in support of the excess return to (NSW) government by NSPs is not accurate as it applies to both network and retail operations of the electricity businesses. The NSW Treasury states that the actual return for NSW NSPs was 5.5 per cent when non-regulated returns from the retail businesses are accounted for, compared to 16.5 per cent claimed by the EURCC.[354] Both the NSW Treasury and the Queensland Department of Employment, Economic Development and Innovation (Queensland DEEDI) oppose the EURCC's proposal to treat government-owned NSPs on a different basis to privately-owned NSPs for cost of debt allowance on the grounds that it would breach the Council of Australian Government (COAG) 1995 Competition Principles Agreement (CPA) to which each state is a signatory.[355] The NSW Treasury also states the EURCC's proposal for government-owned NSPs would result in:

- inappropriate discrimination between NSPs based on ownership;

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351 See for example APIA, Consultation Paper submission, CEG Report, 8 December 2011, pp. 42-45; Ausgrid, Consultation Paper submission, CEG Report, 8 December 2011, pp. 11-20.

352 ENA, Consultation Paper submission, 8 December 2011, p. 55; Grid Australia, Consultation Paper submission, 8 December 2011, p. 68.

353 QTC, Consultation Paper submission, 7 December 2011, p. 2.

354 NSW Treasury, Consultation Paper submission, 23 December 2011, p. 2.

355 NSW Treasury, Consultation Paper submission, 23 December 2011, pp. 5-6; and Queensland DEEDI, Consultation Paper submission, 2 December 2011, p. 3.

- taxpayers not receiving appropriate compensation for the risk of lending to the NSPs; and

- a reduction in allocative efficiency as a result of distortions in resource allocation.[356]

IPART also considers that the EURCC's analysis of government-owned NSPs' excessive profit is flawed. In IPART's view, competitive neutrality fees and corporate taxes are legitimate costs to NSPs that should form part of the required cost of debt allowance.[357] However, IPART believes that there is merit in exploring the option of indexing the cost of borrowing of benchmark private sector businesses in determining the allowed cost of debt.[358]

By contrast, large consumers expressed general support for the EURCC's rule change proposal on the basis that the cost of debt allowances given to the NSPs were in excess of their actual cost of debt, thus contributing to higher network prices. [359] They also supported prescribing the cost of debt methodology in the NER rather than being left to periodic reviews as proposed by the AER.[360]

The ERA similarly endorses consideration of the EURCC's proposal for determining the cost of debt for government-owned NSPs differently to privately-owned NSPs.[361] The Victorian DPI also endorses the EURCC's proposal for indexing the cost of borrowing of privately-owned NSPs in setting the required cost of debt allowance.[362]

## 6.5 Summary of consultant's views

In relation to the DRP issues raised by the AER and the alternative proposal of the EURCC, SFG's conclusion is that the AER and EURCC have not presented substantive evidence that the cost of debt component in the rate of returns for NSPs and gas service providers are overstated.[363] However, SFG agrees that the AER and the EURCC have

356 NSW Treasury, Consultation Paper submission, 23 December 2011, p. 4.

357 IPART, Consultation Paper submission, 8 December 2011, p. 13.

358 Id., p. 14.

359 Amcor, Consultation Paper submission, 5 December 2011, p. 1; ACCI, Consultation Paper submission, 2 December 2011, p. 1; Australian Paper, Consultation Paper submission, 8 December 2011, p. 24 ; BCA, Consultation Paper submission, 22 December 2011, p. 2 ; Bellala, Consultation Paper submission, 2 December 2011, p. 1 ; Central Irrigation Trust, Consultation Paper submission, 5 December 2011, p. 1; MEU, Consultation Paper submission, 8 December 2011, p. 22; NSW Business Chamber, Consultation Paper submission, 8 December 2011, p. 1; QMAG, Consultation Paper submission, 8 December 2011, p. 1; SCCA, Consultation Paper submission, 8 December 2011, p. 1; SSROC, Consultation Paper submission, 8 December 2011, p. 3.

360 Ibid. See also, EURCC, Consultation Paper submission, CME Report, 15 December 2011, p. 19.

361 ERA, Consultation Paper submission, 6 December 2011, p. 5.

362 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 14.

363 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, p. 5.

demonstrated that the cost of debt component is above yields on shorter-term debt securities and above yields on debt issued in prior periods.

While NSPs do not dispute that there is an upward-sloping yield curve, that interest rates have risen in recent years, and there has been relatively more short-term borrowing in recent years compared to history, what is not clear, in SFG's view, from the rule change requests is that the DRP component of the cost of debt allows those businesses to earn abnormal rates of return. SFG suggests that this could well be normal compensation for bearing a refinancing risk which is borne by equity holders.[364] SFG advises that NSPs have issued short term debt in recent years as a result of the illiquidity and high premiums required to issue long-term debt.[365] In SFG's view, if there has been a structural break in the manner in which long-lived assets are financed in the debt market (that is, a paradigm shift to the use of short-term rather than long-term debt), then it is arguable that the benchmark should reflect this structural break.[366] However, SFG notes that the rule change proposals have not provided sufficient evidence that current debt market conditions do not simply reflect a high risk premium required by lenders for financing long-lived assets.[367]

SFG discusses criteria to determine the evidence which would establish that:

(a) there is a bias in the current DRP estimates; and

(b) that the rules are the cause of this bias.

SFG recommends that if it can first be established that the current benchmark approach is systematically biased, then further analysis can determine whether either proposal contained in the AER and the EURCC rule change requests provide a useful means of correcting the bias.[368]

The other important conclusion reached by SFG is that the historical trailing average approach proposed by the EURCC will likely result in a cost of debt component in the regulated rate of return which exhibits lower variation over time.[369] However, if adopted, SFG advises that it would represent a fundamental change from setting regulated rates of return as an estimate of the prevailing cost of funds at the time of the determination. SFG states that if this time-series stability promotes a regulatory objective then it should be considered. However, in its view, this approach would not represent an estimate of the prevailing cost of funds at the time of the determination.[370]

364 Ibid.

365 Ibid.

366 Ibid.

367 Ibid.

368 Id., p. 7.

369 Id., p. 4.

370 Id., pp. 19-22.

In respect of the EURCC's proposal for differential treatment of government-owned NSPs, SFG advises that the errors that have been identified by stakeholders in their submissions on the calculations performed for the EURCC are material. Accordingly, the claims about state government owners receiving excessive returns from their investments in regulated NSPs should be discounted.[371]

SFG also concludes that if the EURCC proposals were implemented, the result would be that a government-owned NSP would charge lower prices than an otherwise identical private-sector NSP.[372] SFG states that the consequences of this differential will include:

- *market distortion* - energy-intensive businesses would have an incentive to locate in (or even move to) areas served by government-owned NSPs. The national competition and competitive neutrality policies seek to remedy this kind of distortion; and

- *permanent government ownership* - since the sale of a government-owned NSP would result in an immediate and material increase in prices, it is unlikely that any such sale would ever be politically feasible.[373]

## 6.6 Analysis

In determining the cost of debt allowance, the DRP component has become contentious because of changes in the market for traded corporate debt in Australia. Subsequent to the GFC, there has been a contraction of long-dated corporate debt. Consequently, the AER has had difficulty in estimating the yield to maturity on long-dated Australian corporate debt with a maturity equal to that used to derive the nominal risk free rate, as required by the NER. In part, the issue has been compounded by the AER's decision in its WACC review to set a benchmark yield to maturity of 10 years, which became problematic during and after the GFC when the market for long dated bonds became limited.

The DRP estimation has consequently resulted in significant debate and merits review processes around an appropriate choice of data to satisfy the benchmark definition. None of the approaches in the NER and NGR seem to have solved this issue.[374] This is evident from the fact the AER has sought to implement the benchmark requirements in a number of different ways over a series of regulatory decisions across the three industries. For example, the approach adopted by the AER has included using the:

- Bloomberg fair value estimates;

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371 Id., p. 38.

372 Id., p. 37.

373 Ibid.

374 Although it is important to note that the NGR does not require the AER to adopt the same approach to estimating the cost of debt as under the NER. However, appeals on the application of both sets of rules are made to the same Tribunal.

- CBASpectrum fair value estimates;
- an average of Bloomberg fair value estimates and CBASpectrum fair value estimates (as a result of the Tribunal decision for ActewAGL's gas distribution business appeal);
- a 75%/25% average of Bloomberg fair value estimates and the yield a bond issued by APA Group;
- a 50%/50% average of Bloomberg fair value estimates and the yield a bond issued by APA Group; and
- an average of a set of bond yields (not including any reliance on fair value estimates).[375]

In each case, the NSPs and gas service providers have sought to challenge the AER's approach on the basis that the AER has relied on a narrow selection of data to estimate the DRP.

The AER and the EURCC claim that the requirements in the NER regarding the DRP has resulted in NSPs being over-compensated in relation to their cost of debt.[376]

Submissions from the NSPs have strongly rejected the premise of the AER and the EURCC's proposals that they earn excessive returns from their allowed cost of debt. The need for improvements to the existing definition of the DRP and consideration of alternative approaches to determining the cost of debt is, however, one of the few WACC issues where there is some level of consensus among most stakeholders.[377]

While it may appear clear that there are difficulties with the existing provisions for estimating the DRP component, and hence the cost of debt under the NER, the Commission considers it is important to analyse carefully and understand clearly the nature of the difficulties. Therefore, this section:

- discusses the evidence presented about whether the current cost of debt allowances under the NER are significantly above the actual cost of debt;
- considers whether the benchmark specified in the NER of Australian corporate bonds is appropriate; and
- reviews whether the range of evidence that can or has been used to estimate the DRP component consistent with the benchmark principle is appropriate.

375 A detailed discussion on different DRP methodologies used by the AER to date is provided in APIA, Consultation Paper submission, CEG Report, 8 December 2011, pp. 39-41; Ausgrid, Consultation Paper submission, CEG Report, 8 December 2011, pp. 11-20.

376 AER, Rule change request, Part B, 29 September 2011, pp. 65, 79-80; EURCC, Rule change request, 17 October 2011 pp. 13-16.

377 See for example ENA, Consultation Paper submission, 8 December 2011, p. 51.

Following that analysis, this Chapter then discusses the issues raised by the EURCC's proposal by:

- considering whether a benchmark or an actual cost of debt should be used in the WACC estimate;
- discussing the use of a trailing average to estimate the cost of debt compared to the current forward looking approach; and
- considering the EURCC's proposal to estimate the cost of debt for government-owned NSPs differently from privately-owned NSPs.

### 6.6.1 Evaluation of whether allowed cost of debt is higher than actual cost of debt

The AER submits that the NSPs are earning an abnormal return because the cost of debt component in the regulated rate of return exceeds the yield to maturity on debt which they could issue today.[378] The NSPs dispute this assessment, and argue that the difference between the regulated rate of return and their cost of debt simply reflects their refinancing risk.[379]

The EURCC also submits that the NSPs are earning excessive returns because the cost of debt element in the regulated rate of return exceeds the interest costs on debt previously issued by the NSPs.[380]

The AER and the EURCC submit that recent DRP allowances exceed the interest rates on debt which NSPs borrowed at, prior to significant increases in interest rates coinciding with the GFC. They have also argued the existence of an upward-sloping yield curve, whereby the yield to maturity on 10 year corporate debt exceeds the yield to maturity on shorter term corporate debt.[381]

The AEMC asked SFG to assess the AER and the EURCC's contention. SFG concludes that neither of these pieces of evidence necessarily implies that the cost of debt allowances have been overstated.[382] With respect to the AER and EURCC's comparison of the current yield to maturity on debt and previously-issued debt, SFG states that interest rates at one point in time higher than a previous point in time does not, in itself, provide an incentive for a business to overinvest.[383] SFG also notes that

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378 AER, Rule change request, Part B, 29 September 2011, pp. 79-80

379 See for example APIA, Consultation Paper submission, CEG Report, 8 December 2011, p. 39; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 140.

380 EURCC, Rule change request, 17 October 2011, p. 16, Table 2.

381 AER, Rule change request, Part B, 29 September 2011, pp. 65, 79-80; EURCC, Rule change request, 17 October 2011 pp. 13-16.

382 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, p. 42

383 Ibid.

the fact that debt was historically sourced at a lower cost is independent of any investment decisions that would be made by the businesses in the present.[384]

To better understand the AER and the EURCC's contention, the Commission has also reviewed a number of reports from market analysts on the Australian stock market quoted energy utilities, being the DUET Group, Spark Infrastructure and SP Ausnet. A number of these reports indicate that the recommended valuations placed on these businesses by the equity analysts assume an ability for the NSPs to raise debt at a rate lower than the cost of debt allowed by the regulator. A number of the reports have indicated that a major reason why they value the NSPs at above their RAB is due to their ability to out-perform their cost of debt allowance.[385]

In its recent draft decision on Powerlink's revenue determination the AER also examined evidence from market analysts in determining the DRP.[386] The AER noted that its estimated benchmark DRP of 319 basis points was within the top of the range considered in the market commentary.[387]

The Commission welcomes submissions on further evidence and views on whether the benchmark DRP approach is likely to overstate the cost of debt, having regard to the question raised by SFG about whether the apparent overstatement at the moment is in fact a reflection of shorter maturity debt leading to a higher refinancing risk for NSPs. The Commission also welcomes submissions on the weight that should be placed on the views of market analysts.

### 6.6.2 Evaluation of whether the benchmark used to estimate the DRP is appropriate

Another possible interpretation of the current difference between the term-to-maturity and yield of debt raised by NSPs, and the benchmark DRP estimates under the NER, is that the benchmark is no longer appropriate. In other words, for NSPs an Australian 10 year corporate bond is no longer an appropriate specification of the benchmark because the financing practices of NSPs have changed, such that a benchmark with a shorter term-to-maturity would be more appropriate.

If the cost of debt is consistently above or below the benchmark allowance, it may suggest that the benchmark should be reconsidered. If this is the case, then there may

384 Ibid.

385 See for example Credit Suisse, *Regulated utilities sector review – Debt risk premium at risk in future WACCs*, November 2011; JP Morgan, The Wire - NSW power sell-off…Round 2; APA refinance, November 2011; Macquarie Equities Research, *DUET Group - Limited RAB growth at fair value*, 8 November 2011; Macquarie Equities Research, *Spark Infrastructure Group - AER rule change - a fight brewing*, 5 October 2011; Merrill Lynch, *APA - Not a done deal*, 14 December 2011; Merrill Lynch, *Australian Utilities - Sustainable yield plus growth*, 5 October 2011; Merrill Lynch, *SP Ausnet - Soft volumes off-set by tariff increase*, 9 November 2011; JP Morgan, *The Wire - DUE receives regulatory approval for DQE sale - Results Previews for AGK, ORG, CEN; Focus on debt*, August 2011. This is only a selection of reports that the AEMC has obtained from some of the agencies.

386 AER, *Draft Decision - Powerlink Transmission Determination 2012-13 to 2016-17*, November 2011.

387 Id., p. 225.

be a case to allow flexibility in the NER for the AER to re-specify the benchmark. Such flexibility would help ensure that consumers benefit from reductions in the cost of debt, and NSPs are appropriately compensated for increases in their cost of debt.

A number of other Australian regulators have reconsidered their benchmark in estimating the DRP.

The NSW regulator, IPART, has recently revised its approach to estimating the DRP.[388] IPART's revised benchmark specification is a five-year term to maturity for Australian corporate bonds (to match a five-year estimate of the risk-free rate) with credit ratings within the range of BBB to BBB+. Importantly, the decision to adopt a five-year term to maturity is primarily based on theoretical considerations, with the relatively greater data availability at this tenor a secondary consideration. However, the sample of bonds available for analysis allows consideration of bonds issued in US dollars and with just a two year term to maturity. From this, it can be inferred that IPART considers that estimation of a benchmark Australian corporate bond with a particular term-to-maturity and credit rating does not necessarily preclude analysis of other data in making this estimate.

Similarly, the ERA has also adopted a different approach to the DRP estimate, called the "bond yield approach".[389] Under the bond yield approach, the ERA has opted to estimate the DRP by constructing a weighted sample of shorter-maturity bonds with time-to-maturity of greater than two years and a credit rating of BBB-/BBB/BBB+ range.[390] In addition, it has also revised its assumed term-to-maturity of the nominal risk free rate by matching it with the length of the regulatory period of five years.[391]

Both IPART and the ERA have attempted to address the limited availability of long term Australian corporate bonds by expanding the selection through the choice of the term-to-maturity. In common are the requirements for the bond to be issued by an Australian entity with a term to maturity of at least two years. They have also moved away from the 10 year assumed term-to-maturity of the nominal risk free rate to five years. There is however, some difference in the precise credit rating specification and the types of bonds they include in their sample. It would seem that both regulators are performing essentially the same benchmarking exercise, but have slightly different views on what the precise benchmark should be.

Following on from the discussion in the previous Chapter about the need for flexibility in the rate of return frameworks, the Commission is initially cautious about specifying a DRP benchmark in the NER. However, to inform further consideration, the Commission would welcome submissions on whether there is evidence that the

388 IPART, *Developing the approach to estimating the debt margin*, Final Decision, April 2011.

389 ERA, *Measuring the Debt Risk Premium – A bond yield approach*, Discussion Paper, 1 December 2010, and ERA, *Final decision on proposed revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, 31 October 2011 (as amended on 22 December 2011).

390 ERA, *Final decision on proposed revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline*, 31 October 2011 (as amended on 22 December 2011), pp. 142-151.

391 Id., pp. 142-151.

benchmark in the NER may have changed, and whether the risk of the benchmark changing over time means that the Commission should not specify the benchmark in the NER. Additionally, the Commission also welcomes submissions on whether the AER should specify the benchmark in any periodic reviews or whether it would be more appropriate to specify it at the time of the determinations, having regard to the most up to date market evidence.

### 6.6.3 Evaluation of the range of data used to estimate the DRP

There is evidence that, in recent years, the imprecision of the DRP estimate is likely to have increased, because there are relatively fewer issues of long-dated corporate debt, compared to short-dated corporate debt.[392] However, while NSPs have acknowledged that the AER's task has been made more challenging in recent years, they dispute that the AER is faced with an impossible task and consider that estimation is made more difficult by the regulator's narrow interpretation of the estimation exercise.

The AER has previously used a limited dataset of long-dated Australian corporate bonds in its analysis, while the NSPs have recommended using a more expansive dataset. This issue is discussed in a number of submissions.[393]

The AEMC has asked SFG to comment on whether the current specification of the requirements of DRP makes it impossible to estimate. In its report, SFG advises that the important interpretation question is whether the benchmark specification – an Australian corporate bond with term to maturity equal to that used in estimating the risk-free rate – defines the dataset available for analysis, or whether it represents a benchmark which can be estimated with a more expansive dataset, appropriately analysed.[394]

SFG states that the Tribunal's interpretation appears to be that the benchmark specification in the NER does not prescribe the dataset because the Tribunal allowed analysis of bonds which had credit ratings different from benchmark specification and at terms to maturity below benchmark specification.[395]

As SFG explains, the debate over the appropriate dataset is just one example of the trade-off between relevance and reliability in any benchmarking exercise.[396] Notably, SFG states that corporate bonds issued by the Australian companies in Australian dollars with a maturity of exactly 10 years with a credit rating equal to the benchmark

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392 Ausgrid, Consultation Paper submission, 8 December 2011, pp. 21-22; APIA, Consultation Paper submission, CEG Report, 8 December 2011, p. 49-50; ENA, Consultation Paper submission, 8 December 2011, pp. 45-46; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp 138-140.; Financial Investor Group, Consultation Paper submission, 8 December 2011, p. 42; QTC, Consultation Paper submission, 7 December 2011, p. 21.

393 Ibid.

394 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, p. 43.

395 Id., p. 44.

396 Ibid.

rating will be most relevant for analysis. However, SFG suggests that a strict adoption of these criteria, especially in recent periods, is likely to result in a highly restricted (or even non-existent) sample.[397] In SFG's view, relaxing some criteria to expand the data available for analysis is likely to generate a more reliable dataset in a statistical sense, because firm- or contract-specific features affecting the yield will carry less weight, but the sample is less relevant to the benchmark to be estimated.[398]

More relevantly, SFG concludes that:

> "It is not immediately clear why any source of data is excluded from consideration in order to estimate the benchmark yield on Australian corporate debt. Yields on instruments other than long-dated corporate debt are still likely to contain information which is relevant to estimating the benchmark yield. It is simply a matter of degree. For example, premia on credit default swaps are worthy of consideration for analysis. In the Australian market these securities are quoted on BBB rated corporate debt, but only denominated in US dollars. These are likely to contain information relevant to estimating the debt risk premium on a benchmark corporate bond, albeit with assumptions required about currency conversions.[399]"

With respect to the NER, it is a matter of interpretation as to whether the benchmarking criteria represent a high level principle or prescription. The AER's interpretation is that it is the prescription of the requirement for the DRP to be based on a benchmark corporate bond rate which has resulted in the cost of debt being overstated. The interpretation that the NER permits the use of more reliable but less relevant data for estimation of the benchmark is consistent with the NER being a statement of high level principle. The key point appears to be that the specification of an appropriate benchmark, at a conceptual level, should not be driven by specific data availability issues.

However, there may be practical considerations in the range of data that can be used. The AER can only measure what it can observe, but it does not follow that its conceptual benchmark should fluctuate according to the dataset it uses to observe the DRP benchmark. For example, SFG notes that the practical issue involved with respect to the DRP is that:

> "…we can estimate yields on five-year debt with more precision than yields on ten-year debt. This does not necessarily imply that the term to maturity of an efficient financing structure has changed. It could be the case that borrowers and lenders have simply been able to come to agreement at a short term to maturity, but have been unable to reach agreement at longer terms.[400]"

397 Ibid.

398 Ibid.

399 Id., p. 45.

400 Ibid.

The Commission's initial view is that the NER and NGR should not limit the range of evidence that the AER or the ERA can consider when estimating the DRP for a specific benchmark. It should be for the regulator to consider the appropriate weight that should be given to different forms of evidence. Such ability of the regulator to take into account datasets it deems appropriate has been confirmed by the Tribunal.[401] The Commission welcomes submissions on whether there are any reasons why the regulator should be constrained as to the range of evidence it can consider to estimate the DRP for a specific benchmark.

### 6.6.4 EURCC proposal – actual or benchmark cost of debt

The discussion so far in this Chapter about the cost of debt issues has focussed on the approach adopted to date in the NER and application of the NGR, where the cost of debt is set as a benchmark established through the DRP for the NSP rather than being based on a NSP's historical cost of debt. The EURCC's rule change request moves towards the use of a historical cost of debt and somewhat away from the use of a benchmark. However, in practice the EURCC's rule change request is for the use of actual state government borrowing costs for government-owned NSPs and a trailing average benchmark of debt costs for privately-owned NSPs, on the basis that this will better reflect privately-owned NSPs actual debt costs than the current approach.

As SFG's explains, there is some precedent in other countries, particularly the UK, for the use by regulators of approaches that use a trailing average type approach, similar to that proposed by the EURCC. SFG discusses the approaches used by Ofgem and the England and Wales water regulator Ofwat.[402] However, such an approach would be a significant departure from the practice to date in Australia.

A range of stakeholders have indicated a level of support for some of the concepts put forward in the EURCC's proposal for estimating the cost of debt for privately-owned NSPs. However, many of these comments have been made at a conceptual level and have not considered in detail the compatibility of the EURCC's proposal with the overall framework for estimating the WACC, and how the detailed application of the EURCC's proposal would work in the NER. Discussed below are the key differences between the EURCC's approach and the current approach to estimating the cost of debt. The Commission welcomes more detailed and specific submissions on these issues.

### 6.6.5 Historical trailing average approach versus forward-looking approach to estimating the cost of debt

The EURCC proposal would mean that the cost of debt component of the rate of return would provide NSPs with compensation for interest rates prevailing in the past, rather than compensation for the risk of securing debt finance in the market conditions

401 See para 45 in Application by ActewAGL Distribution [2010] ACompT 4 (17 September 2010) .

402 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, Appendix 2.

prevailing at the time of their regulatory determinations. This proposal represents a fundamentally different approach to determining rates of return than currently required by the NER. Under Chapters 6 and 6A of the NER, the WACC reviews include an explicit requirement for the rate of return to be a forward looking estimate commensurate with prevailing conditions in the market for funds.[403] In addition, the rules also state the cost of debt should to reflect the *current cost of borrowings* for comparable debt [emphasis added].[404]

In its analysis, SFG states that the general approach to estimating the cost of debt is to ask, "if an investment equal to the regulated asset base were made today, what per unit price would allow the investor, on average, to receive cash flows with net present value equal to that regulated asset base?"[405] In SFG's view, this is achieved by setting the regulated rate of return equal to the "true cost of capital" at the time of the regulatory determination.

Fundamentally the EURCC proposes to set the regulated rate of return at something other than the cost of capital at the time of making regulatory determinations for NSPs. SFG states that the cost of capital is the discount rate the market will apply to expected future cash flows.[406]If this view is correct, then if regulated prices are set at a level which reflects a regulated rate of return other than the cost of capital, the present value of expected cash flows would no longer be equal to the RAB. Consequently, as stated by SFG, in any given period regulated prices could be higher or lower than the RAB, and this "present value" relationship will no longer hold.[407]

In SFG's view, the implication of breaking the present value relationship is that investment decisions will be distorted. When regulated rates of return are below the efficient cost of capital the incentive is to delay investment until regulated returns increase; when regulated rates of return are above the cost of capital the incentive is to increase the RAB. As noted by SFG, this does not necessarily rule out the use of a trailing average estimation technique for setting regulated rates of return, but because it would be such a fundamental change, the reasons for making it and the benefits that would flow from it should be clearly articulated.[408]

SFG also states that if it can be demonstrated that the benefits of a regulated rate of return which is less variable over time outweigh the costs associated with investment distortions, then a trailing average should be considered.[409] However, SFG is of the view that the EURCC approach simply demonstrates that the trailing average is less volatile than the cost of capital at each point in time, and that there will be less impact on estimation error of short periods when debt markets are less liquid.

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403 NER clauses 6.5.4(e)(1) and 6A.6.2(j)(1).

404 NER clauses 6.5.4(e)(2) and 6A.6.2(j)(2).

405 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, p. 41.

406 Ibid.

407 Ibid.

408 Id., p. 45.

Given that the EURCC's proposal attracted a significant level of stakeholder support for its concepts, the Commission is keen to ensure that it has fully understood and investigated the approach prior to making a draft rule determination. The EURCC's approach would reduce the estimation error concerns associated with Australian corporate debt data availability. To the extent that forecasting a forward looking cost of debt is particularly challenging, then the use of historical evidence to make the forecast could be argued to be at least as robust as any forward-looking estimate.

However, SFG raises a number of important issues about what the use of a trailing average approach means for the estimation of the cost of capital as the estimate of the cost of debt would no longer be the best available at the time it was made or commensurate with the prevailing conditions in the market. This raises the question whether the EURCC's approach is consistent with the NEO, and in particular would it promote efficient investment and use of regulated assets? The Commission seeks submissions on whether the potential benefits of using a trailing average would be sufficient to outweigh the potential costs if the estimate is less robust at reflecting the prevailing cost of debt for NSPs.

Separate to the views on the merits of the EURCC's proposal, the Commission is also interested in submissions on whether it would be appropriate to require the use of such an approach in the rules. The Commission has raised some concerns about prescription in Chapters 6 and 6A regarding the rate of return more generally in the previous Chapter. In this regard the Commission is initially cautious about prescribing in the NER, whether in the form proposed by the EURCC, or in another form, a detailed approach of this nature. The Commission welcomes submissions on whether, if it considered the EURCC's proposal to have some merit, the rules should permit and facilitate discretionary use of the approach by the regulator without mandating it.

### 6.6.6 Should the cost of debt allowance be determined differently based on ownership?

The EURCC's proposal to require the cost of debt of government-owned NSPs to be determined differently to privately-owned NSPs has been controversially received by many stakeholders. The primary opposition to the EURCC's proposal is that ignores the fact that government-owned NSPs are subject are required to pay competitive neutrality fees (or government guarantee fees) as part of implementation of the CPA, signed by all Australian governments and committing them to, inter alia, applying competition principles to government activities.

However, the EURCC in its proposal claims that the payment of competitive neutrality fees by government-owned NSPs to their jurisdictional government owners is inconsistent with the CPA. The EURCC states that NSPs are monopolies and as such, their captive customers are unable to avail themselves of the services of a competitor.[410] In EURCC's view, there is no reason to imagine that

409 Ibid.

410 EURCC, Rule change request, 17 October 2011, p. 31.

government-owned NSPs are privately-owned on the basis of that they cannot crowd-out non-existent competitors.[411]

**Competitive neutrality policies and principles**

The CPA includes a number of policies and principles that are relevant to the EURCC's contention. They include:

> "3(1) The objective of competitive neutrality policy is the elimination of resource allocation distortions arising out of the public ownership of entities engaged in significant business activities: Government businesses should not enjoy any net competitive advantage simply as a result of their public sector ownership. These principles only apply to the business activities of publicly owned entities, not to the non-business, non-profit activities of these entities.
>
> ...
>
> 3(4)(b) [T]he Parties will impose on the Government business enterprise:
>
> (i) full Commonwealth, State and Territory taxes or tax equivalent systems;
>
> (ii) debt guarantee fees directed towards offsetting the competitive advantages provided by government guarantees; and
>
> (iii) those regulations to which private sector businesses are normally subject, such as those relating to the protection of the environment, and planning and approval processes, on an equivalent basis to private sector competitors.[412]"

The Commission does not agree with the EURCC's views on the application of the competitive neutrality principles to government-owned NSPs.

The objective of competitive neutrality policy, as stated in subclause 3(1) of the CPA, is the elimination of resource allocation distortions arising out of the government ownership of businesses. The rationale behind the implementation of competitive neutrality for government-owned businesses such as the NSPs is that resource allocation distortions can arise where government-owned businesses face different costs or disciplines than private sector businesses. For example, the National Competition Council states that:

> "[I]f a government business is not required to earn a return on the capital invested in the business or even cover operating costs, then it may be able to underprice the goods and services it produces. If this leads to the government business attracting custom from its more efficient competitors,

411 Ibid.

412 Competition Principles Agreement - 11 April 1995 (as amended to 13 April 2007).

> then the community's scarce resources are not being used as well as they might be. The underpricing may also encourage 'overuse' of the good or service, encouraging the business to invest in new plant and equipment that it would otherwise have not required.[413]"

Contrary to the EURCC's view, the fact that there is no competitive pressure in the output markets of monopoly NSPs does not necessarily mean that competitive neutrality principles should not apply. This is because resource allocation distortions are not only limited to outputs of government-owned businesses, but also to input markets. Government-owned businesses that operate inefficient production processes are likely to use more resources such as raw materials, physical capital, management and labour, and technical know-how, than would be necessary to produce a given level of output. This reduces the availability of resources to other sectors of the economy and increases the cost to all consumers. Inefficient production processes also increase costs of production, undermining the government-owned business's financial performance.

Even where there is no actual or potential competition, the adoption of competitive neutrality principles can encourage greater efficiency in resource allocation. It will mean, for example, that governments are better informed about the actual cost of providing goods and services, allowing for improved decisions about how to provide those goods and services. This is particularly relevant to government-owned NSPs that, as the EURCC's points out, do not have any competitors.

In any event, the Commission recognises that each state and territory is a signatory to the CPA and, as such, is required to apply the competitive neutrality principles in a way they consider to meet that obligation. Furthermore, as submissions from the NSW Treasury and the Queensland DEEDI point out, in accordance with the CPA, the respective state governments have moved to corporatise the NSPs they own which requires them to operate in a commercially-oriented manner and compete with the private sector (at least in the resource input markets) on the same basis. These are policy decisions by governments that are outside the scope of NER to deal with.

**Debt neutrality fees**

The EURCC proposal also assumes that state governments provide debt financing to their NSPs at the government's cost of borrowing. However, as noted by Queensland DEEI and NSW Treasury the government-owned NSP are required to pay "competitive neutrality" or "guarantee" fees on the debt raised for the NSPs by the government.[414] Both Queensland DEEDI and NSW Treasury note that the fee that is charged is an estimate of what the business would pay for its debt funding on a stand-alone basis. They contend that these fees must be included in any analysis of the cost of debt funding for government-owned NSPs to reflect the fact that a stand-alone

413 National Competition Council, *Competitive neutrality reform: issues in implementing clause 3 of the Competition Principles Agreement*, January 1997, p. 5.

414 Queensland DEEDI, Consultation Paper submission, 2 December 2011, p. 3; NSW Treasury, Consultation Paper submission, 23 December 2011, p. 6.

NSP would have a lower credit rating and would have to pay an appropriate spread above the state's borrowing rate.[415]

The Commission agrees with the views of Queensland DEEDI and the NSW Treasury. The CPA in subclause 3(4)(b)(ii) clearly requires that the cost of debt of government-owned NSPs is comparable to that of the private sector. Competitive neutrality does not require that government-owned NSPs borrow from the market at a full debt neutral rate. Rather, since they are able to borrow funds at a lower rate than the privately-owned NSPs due to their government ownership, they are required to pay a debt neutrality charge.

The amount of any debt neutrality fees paid by government-owned NSP are therefore legitimate costs that need to be accounted for. Even if government-owned NSPs' cost of debt allowance were to be set in reference to their interest rate cost, the fact they are required to pay debt neutrality charges means that regulator would be required to take into account of this cost as a separate cost category. For example, it is conceivable that government-owned NSPs would require the regulator to include compensation for the competitive neutrality fees or government guarantee fees as part of debt raising costs in the cost of debt allowance.

**Distortions in NEM pricing signals**

The EURCC's proposal, if implements, could also create significant distortions in the upstream and downstream markets of the NEM purely by virtue of ownership. The proposal would give rise to circumstances where NSPs operating in different geographic regions would be required to set prices that are differentiated by ownership rather than by reference to the underlying economic costs of providing those services. This could potentially lead to an artificial incentive for overinvestment in generation and network capacity in the lower price regions, along with under-investment in demand side initiatives, undermining the principles of allocative and dynamic efficiency.

Furthermore, the EURCC proposal also ignores the downstream market that would arise where different network charges result purely on account of ownership. It could create an artificial bias for governments that own network assets to continue to own those assets, given that a material upward impact on prices would occur if assets were sold.

**Government's role as a taxing authority and shareholder**

The EURCC also contends that "the regulatory regime is already providing investment returns to governments that own NSPs that are far in excess of what the AER has anticipated in its price control determinations, or that can be considered to be reasonable.[416] The main basis for this contention is that governments, as owners of the

415 Queensland DEEDI, Consultation Paper submission, 2 December 2011, p. 3; QTC, Consultation Paper submission, 7 December 2011, p. 8; NSW Treasury, Consultation Paper submission, 23 December 2011, pp. 8-9.

416 EURCC, Rule change request, 17 October 2011 p. 38.

NSPs, receive tax payments from government-owned NSPs under the tax equivalents regimes. In its report, SFG advises that this claim by the EURCC appears to confuse the two roles of the government:

- the state [government] is the shareholder and, as for any other shareholder, it is appropriate for the state [government] to earn a return on its equity capital investment (via dividends) that is consistent with the risk of that equity investment; and

- the state [government] is the taxing authority and receives taxation payments from the businesses, where those taxation payments are calculated in the same way as for private sector NSPs.[417]

The EURCC also argues that the dividends paid to the state governments as the shareholder and the taxation payments paid to the state governments as the taxing authority should be added together when calculating the return on equity. On this issue, SFG notes that when taxation revenues are included in this calculation, the resulting estimate of the return on equity would be disproportionate to the risk that is borne by the jurisdictional governments as the shareholder.[418] SFG states that the return received as a shareholder (as dividends) should be compared with the risk borne as a shareholder and taxation revenues received as the taxing authority should have no part in this comparison.[419]

The Commission agrees with SFG's conclusion on this issue. In addition, the Commission notes that the CPA requires governments to apply tax equivalent payment systems to their businesses. Tax equivalent systems already apply to all government-owned NSPs.[420]

## 6.7 Initial position

The Commission's recognises that the requirement in the NER regarding the estimation of the DRP has resulted in significant debate and merits review processes around an appropriate choice of data to satisfy the required benchmark definition. The problem appears to be compounded by the fact that the term-to-maturity and the credit ratings specified by the AER for comparable Australian corporate bonds in its 2009 WACC review no longer appear to be appropriate to match the nominal risk free rate. This is because the number of long-term Australian corporate bonds on issue has contracted significantly since the onset of the GFC.

The Commission accepts that there is evidence to indicate that the DRP allowances determined by the AER appear to exceed the interest rates on debt at which NSPs have

417 SFG Consulting, Preliminary analysis of rule change proposals, Report for the AEMC, 27 February 2012, p. 35.

418 Ibid.

419 Ibid.

420 For example see sections 128 and 129 of the *Government Owned Corporations Act 1993* (Qld); section 15 of *State Owned Corporations Act 1989* (NSW).

historically borrowed. However, the Commission is of the view that the apparent overstatement of debt costs at the moment may be a reflection of shorter maturity debt being raised by NSPs, leading to higher refinancing risks. This precludes the Commission from definitively concluding that the NSPs are currently being over-compensated by the cost of debt allowances. This is because, as SFG advises, the fact that debt was historically sourced at a lower cost is independent of any investment decisions that would be made by the NSPs today.

On the other hand, the views of market analysts suggests that the cost of debt allowances are generous because NSPs that are listed on the Australian Stock Market can raise debt at a rate lower than the cost of debt allowed by the regulator. The Commission seeks further submissions on this issue.

In relation to the DRP benchmark specification, the Commission's initial view is that the regulator should have the flexibility to re-specify the benchmark when it appears that the cost of debt is consistently above or below the benchmark allowances. A number of other Australian regulators have reconsidered their benchmark in estimating the DRP. Such flexibility is likely to ensure that consumers benefit from reductions in the cost of debt, and NSPs are appropriately compensated for increases in their cost of debt. However, the Commission has some concerns with the AER's proposal to include the DRP estimation methodology as part of its periodic WACC reviews. As discussed in the previous Chapter, the Commission is not convinced that determining all parameters in periodic reviews is the most appropriate approach, given the difficulties in making subsequent adjustments to parameter values under the current frameworks. Such an approach risks not delivering a rate of return that reflects efficient financing costs for NSPs.

The Commission believes that the use the trailing average approach to estimate the cost of debt as proposed by the EURCC has merit, although it will require consideration of some fundamental principles that underpin the existing rate of return frameworks. These must be carefully weighed against the benefits a historical benchmark cost of debt approach may provide. However, having regard to the need for need for flexibility in the rate of return frameworks discussed in the previous chapter, the Commission is cautious about prescribing the use of a trailing average approach in the NER. That approach does not provide the level of flexibility that appears to be desirable in a rate of return framework. A methodology such as this included in the rules may not allow the AER to react to change and respond to market conditions in a timely manner. In proposing this methodology, the EURCC does however raise a number of pertinent issues that should be considered by the regulator. The Commission would like to explore the possibility of allowing the rules to permit, but not require the regulator to consider, and if appropriate adopt, an option such as this.

In relation to the EURCC's proposal to determine the cost of debt allowances for government-owned NSPs differently to privately-owned NSPs, the Commission considers that such arrangements would not be appropriate. This is because:

- it fails to recognise that competitive neutrality principles also apply to correct resource allocation distortions that can result in the input as well as output markets of government-owned monopoly businesses;
- it does not recognise autonomy of state and territory governments to make policy decisions in compliance with the CPA to corporatise their NSPs and apply commercial disciplines;
- it does not factor in the role of the debt neutrality fees as required under the CPA and the legitimate impact it has on the debt raising costs of government-owned NSPs;
- it will potentially create artificial geographical market distortions in generation and network capacities across the NEM because the pricing signals that would be created due to network ownership;
- it could remove the option of any future sale or other divestiture of government-owned NSPs; and
- it confuses the roles of shareholder and taxing authority arrangements of governments as owners of NSPs.

## 6.8 Issues for further comment

To assist the Commission in the next stage of its assessment, stakeholders are invited to respond to specific questions as noted below.

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| **Question 30** | **Is the benchmark DRP approach 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?** |
| **Question 31** | **What are the pros and cons of the recent approaches taken by 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?** |

| | |
|---|---|
| **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 of using a trailing average and do they outweigh the potential 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?** |

# 7 Regulatory determination process

**Summary**

- The NER set out, with some prescription, a process by which the AER is to determine revenues (and in some cases, prices) of NSPs.
- The AER has raised a number of issues that relate to the ability of stakeholders to engage effectively in the regulatory determination process. Related to this is whether the AER can adequately consider all material submitted as part of its process.
- The Commission shares some of the AER's concerns but considers that as well as specific amendments to the process it is necessary to consider the process as a whole to ensure stakeholders have sufficient opportunity to provide input and the AER has sufficient time for its decisions.
- Process issues must be considered alongside the other issues raised.

## 7.1 Objective

This Chapter largely concerns the ability of stakeholders to engage effectively in the regulatory determination process. Related to this is whether the AER can consider adequately material submitted to it as part of that process. These matters must be considered in the context of the other issues raised as part of the AER's electricity rule change request, including the capex and opex allowances framework discussed in Chapter 3 of this directions paper.

In the Chapter 6A rule determination, the AEMC stated:

> "... that well designed procedural requirements assist in ensuring that the regulator administers the regulatory regime in an appropriate manner. This includes providing opportunities for regulated businesses and interested stakeholders to make submissions to the regulator and the opportunity for full and thorough analysis of the submissions and the regulator's decisions (including draft decisions). Transparent decision making in this way is conducive to reducing regulatory risk, and the probability of error and decreasing the administrative costs of regulation. Appropriate time constraints within this process also assist in ensuring that regulatory decision-making is timely and efficient.[421]"

While concerned with the regulatory determination procedure for economic regulation of transmission services, this statement sets out objectives that are relevant to regulatory processes more generally. When considering the regulatory processes in the

421 AEMC, *Economic Regulation of Transmission Services*, Rule Determination, 16 November 2006, p. 33; Chapter 6A of the NER relates to electricity transmission.

NER, however, additional factors must also be taken into account.[422] In 2008, the merits review process was introduced into the NEL (and at the same time Chapter 6 was introduced by the MCE).[423] The volume and scope of material being assessed by the AER, and consulted upon with stakeholders, have increased over time. It is therefore opportune to review the current regulatory determination process against the key objectives articulated by the AEMC in 2006.

Chapter 2 sets out an overall framework for assessing the rule change requests. The key objective set out in that Chapter for the purposes of this Chapter is achieving certainty for investors, and efficiency of investment and transparency for investors and consumers. In terms of the regulatory determination process this can be achieved by, among other things:

- consistency of AER decisions over time and appropriate checks and balances on regulatory decisions. Reducing administrative costs will contribute to the overall efficiency of the regulatory framework, and, in turn, to the NEO; and

- enabling stakeholders, in particular consumers, to participate in the regulatory determination process effectively so that their preferences are factored into investment decisions. This will help to ensure that NSPs provide the level of service that consumers demand.

Given the importance of trying to ensure that the regulatory determination process works effectively and as intended, prior to the draft rule determination the Commission is likely to engage with a range of stakeholders, including the AER, NSPs and consumer representatives to discuss options to address the range of issues raised in this Chapter. This is in addition to considering the responses to this directions paper.

The Commission also wishes to make the observation that while the NER can describe in detail how the regulatory determination process is to work, it cannot prescribe every part of the process. In the end, the interaction of the AER, the NSPs and the other stakeholders will also contribute to the success of the regulatory determination process. This might include those parties seeking wider opportunities for engagement. In Great Britain, for example, the Commission understands that there is more informal interaction, and at an earlier stage, between Ofgem and NSPs, particularly on the more technical (engineering) requirements of the network. The Commission invites submissions from stakeholders on any factors or principles that would promote an effective regulatory determination process.

422 In this Chapter, references to "regulatory determination" are to the distribution determination and revenue determination in each of Chapter 6 and 6A of the NER respectively.

423 Chapter 6 of the NER relates to electricity distribution.

## 7.2 NSP submissions received during a regulatory determination process

### 7.2.1 Context

To reduce regulatory error under the current regulatory determination processes, all stakeholders are permitted to provide submissions throughout the process. The AER is concerned 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. This does not provide other stakeholders and the AER sufficient time to scrutinise this material.[424] The AER proposes placing limitations on NSP submissions to address this.

### 7.2.2 Current rules

Generally, 13 months before the expiry of a regulatory determination, NSP submits a regulatory proposal to the AER.[425] Any stakeholder can make submissions on a NSP's regulatory proposal. Submissions must usually be provided within 30 business days after publication of the regulatory proposal.[426]

The AER must then publish a draft regulatory determination. Although not explicit for distribution, for transmission the draft regulatory determination must be published as soon as practicable but no later than six months after a TNSP submits its regulatory proposal.[427] Any stakeholders can make submissions on the AER's draft regulatory determination. Stakeholders have at least 30 business days from the draft regulatory determination in distribution to make submissions, and in transmission at least 45 business days after the predetermination conference (which usually occurs a few weeks after the draft regulatory determination).[428] In practice these submissions are usually due around a month after the revised regulatory proposal is due.

Following the draft regulatory determination, NSPs may submit a revised regulatory proposal not more than 30 business days after the draft regulatory determination has been published.[429] The revised regulatory proposal may only incorporate the substance of any changes required to address matters raised by the draft regulatory determination or the AER's reasons for it.[430] Stakeholders may also make submissions on the revised proposal.

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424 In this Chapter, unless clearly specified, references to "regulatory proposal" are to regulatory proposals in Chapter 6 and revenue proposals in Chapter 6A.

425 NER clauses 6.8.2(b) and 6A.10.1(a)(1).

426 NER clauses 6.9.3(c) and 6A.11.3(c).

427 NER clauses 6.10.2 and 6A.12.2(a).

428 NER clauses 6.10.2(c) and 6A.12.2(c).

429 NER clauses 6.10.3(a) and 6A.12.3(a).

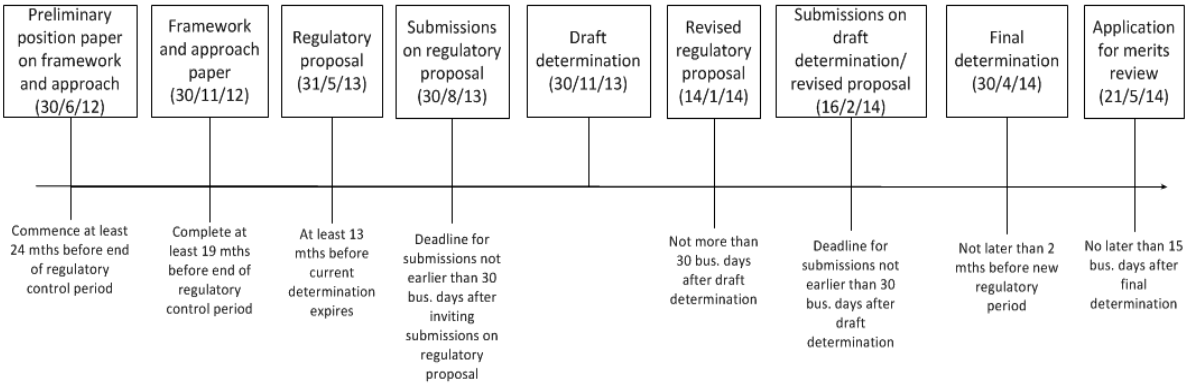
430 NER clauses 6.10.3(b) and 6A.12.3(b).

In making its final regulatory determination, the AER must consider any submissions made on the draft regulatory determination, or on any revised regulatory proposal.[431] The final regulatory determination must be published as soon as practicable but not later than two months before the commencement of the new regulatory control period.[432]

The AER has the discretion to consider late submissions.[433]

Set out below is a sample distribution regulatory determination process time line, with possible dates for Ausgrid included.

**Figure 7.1 Regulatory process time line (with sample dates)**




**Previous Chapter 6A rule determination**

The current arrangements were considered holistically as part of the Chapter 6A rule determination. With respect to the overall framework, the AEMC's intent was to establish well designed procedural requirements that would compel the AER to administer the regulatory regime in an appropriate manner and for TNSPs to put forward complete and thorough initial and revised regulatory proposals.[434] This entailed providing opportunities for all stakeholders to make submissions to the AER.[435] For instance:

- the 13-month time constraint was imposed with the aim to ensure efficient and timely decisions;[436]
- the 30-day time constraint for NSPs to submit their revised regulatory proposals was to provide additional discipline in the submission of compliant regulatory proposals, reflect the constraints placed on the AER for preparation of a draft

431 NER clauses 6.11.1 and 6A.13.1(a).

432 NER clauses 6.11.2 and 6A.13.3.

433 NER clauses 6.14(a) and 6A.16(a).

434 AEMC, *Economic Regulation of Transmission Services*, Rule Determination, 16 November 2006, pp. 110-113.

435 Ibid.

436 Id., pp. 110, 112.

regulatory determination, and be consistent with the relevant constraint on resubmission following a draft regulatory determination by the AER (ie only to address matters raised in the draft regulatory determination);[437] and

- the scope of the revised regulatory proposals was restricted to reduce the possibility of ambit claims at the start of the regulatory determination process.[438]

The above statement can equally be applied to Chapter 6. MCE Standing Committee of Officials (MCE SCO) stated in its amendments to Chapter 6 that Part E of Chapter 6 is equivalent to Part E of Chapter 6A.[439]

### 7.2.3 AER proposal

The AER considers that the objective of the rules was to encourage NSPs to provide complete initial and revised regulatory proposals, reflecting their best available information with enough time for effective consultation and the AER to make timely decisions.[440] However, the AER considers that this objective is not being currently achieved for the following reasons:[441]

- NSPs are undermining the objective of the current rules by effectively providing late initial and revised regulatory proposals in the form of submissions; and

- due to this, the AER and other stakeholders do not have sufficient opportunity to properly assess this further NSP information.

However, the AER notes that there are appropriate circumstances where NSPs can make submissions.[442] This relates to common issues across NSPs' initial or revised regulatory proposals that are being assessed concurrently by the AER, where there are material differences in the methodologies, assumptions or reasons applied across concurrent initial or revised regulatory proposals eg a methodology for forecasting demand.[443]

To address this, the AER proposes that:[444]

- NSP submissions would be limited to material differences with another concurrent NSP initial or revised regulatory proposal;

437 Id., p. 112.

438 Id., pp. 112-113.

439 MCE SCO, *Changes to the National Electricity Rules to Establish a National Regulatory Framework for the Economic Regulation of Electricity Distribution*, Explanatory Material, April 2007, p. 20.

440 AER, Rule change request, Part B, 29 September 2011, pp. 85-87.

441 Ibid.

442 Id., p. 87.

443 Id., pp. 87-88.

444 Id., pp. 88-89.

- NSPs would be unable to make submissions on their own initial and revised regulatory proposals, and the AER's draft decision;
- NSPs would only be able to respond to the AER's draft decision in the form of their revised regulatory proposals;
- NSPs would also be able to make submissions on the AER's proposed negotiated service criteria released concurrently with the NSPs' initial regulatory proposals, and submissions from other stakeholders into the regulatory determination process; and
- the AER would not be permitted to consider late initial or revised regulatory proposals or submissions that do not comply with the above restrictions.

The AER considers that its proposed rules would prevent NSPs from making late initial or revised regulatory proposals in the form of submissions.[445] This would give other stakeholders a proper opportunity to consider all the relevant information prior to making submissions to the AER, and avoid altering the existing timeframes for the AER to assess the NSPs' initial and revised regulatory proposals, and stakeholder submissions.[446]

### 7.2.4 Submissions

NSPs agree with the need for adequate consultation time, but disagree with the AER's characterisation of the problem and proposed solution.[447] NSPs consider there are legitimate reasons for NSPs providing submissions such as material impacts from external circumstances to the regulatory determination process (eg the Victorian Bushfire Royal Commission), inability for NSPs to collect all relevant evidence to respond to AER draft decisions (especially over the Christmas and New Year period), a new AER approach developed or new information relied upon by the AER that was not subject to consultation, and alternative approaches or evidence raised by stakeholders.[448] They consider that without allowing NSPs the ability to provide submissions in such circumstances, the risk of regulatory error could increase and therefore lead to merits reviews, resulting in procedural unfairness and inconsistencies with the NER and NEL.[449]

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445 Id., p. 89.

446 Ibid.

447 ENA, Consultation Paper submission, 8 December 2011, pp. 56-60; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 33-34; Grid Australia, Consultation Paper submission, 8 December 2011, p. 74; Jemena, Consultation Paper submission, 8 December 2011, p. 88.

448 ENA, Consultation Paper submission, 8 December 2011, pp. 57-59; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 162-163; Grid Australia, Consultation Paper submission, 8 December 2011, pp. 74-75; SP AusNet, Consultation Paper submission, 8 December 2011, pp. 21-22.

449 ENA, Consultation Paper submission, 8 December 2011, pp. 57-60; Ergon Energy, Consultation Paper submission, 8 December 2011, p. 16; ETSA, CitiPower and Powercor, Consultation Paper

To improve stakeholder participation and to provide for adequate consultation, the NSPs propose a new process for submissions and cross-submissions following the draft decision and revised regulatory proposal, similar to that currently being utilised by the NZ Commerce Commission.[450] This new process would require an additional two weeks for consultation. In addition to the NSPs' proposed new process, NSPs propose an additional two weeks for the revised regulatory proposal to be submitted.[451]

Most other stakeholders support the AER proposal. However, although the Victorian DPI agrees that voluminous material during a regulatory determination process does not allow for effective consultation, it is concerned that the AER proposal may not allow for due process.[452] The Victorian DPI proposes amending the timeframe for the regulatory determination process to allow for the introduction of an AER issues paper early in the process which may reduce the volume of information from NSPs.[453]

### 7.2.5 Analysis

One reason why the regulatory determination process does not appear to have worked as intended is that a much greater quantity of material has been submitted to the AER by NSPs after the draft regulatory determination, both directly in response to the draft regulatory determination and through subsequent submissions, than was envisaged when the AEMC developed the Chapter 6A provisions in 2006. This may be due in part to the introduction of merits review.[454] As set out above, the existing NER only permit a NSP's revised regulatory proposal to incorporate material required to address matters raised by the draft regulatory determination or the AER's reasons for it.

The Commission accepts that new information may become available to NSPs (such as issues arising from unforeseen events) and that circumstances may change. However, the quantity of information being submitted suggests that it is not just these types of unexpected events that are leading to the additional information being submitted.[455] Further, in circumstances where a restriction is imposed on the revised regulatory

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submission, 8 December 2011, p. 35; ENA, Consultation Paper submission, Attachment D, 8 December 2011, pp. 8-9; Grid Australia, Consultation Paper submission, 8 December 2011, pp. 7, 75-76; Jemena, Consultation Paper submission, 8 December 2011, p. 99; SP AusNet, Consultation Paper submission, 8 December 2011, pp. 21-22.

450 ENA, Consultation Paper submission, 8 December 2011, pp. 59-61; Ergon Energy, Consultation Paper submission, 8 December 2011, p. 16; ENA, Consultation Paper submission, Attachment D, 8 December 2011, p. 10; Grid Australia, Consultation Paper submission, 8 December 2011, p. 76; Jemena, Consultation Paper submission, 8 December 2011, p. 102.

451 ENA, Consultation Paper submission, 8 December 2011, p. 61; Ergon Energy, Consultation Paper submission, 8 December 2011, p. 16.

452 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 12.

453 Id., p. 13.

454 The merits review provisions prevent the Tribunal from considering, at a key stage in the merits review, any material beyond that which was provided to the AER before its final regulatory determination was made.

455 AER, Rule change request, Part B, 29 September 2011, p. 86.

proposal, the NER should not permit this restriction to be circumvented through the use of submissions.

The late submissions provided by NSPs appear to be contributing to a broader problem with the current regulatory determination process in that the process is not providing an opportunity for all stakeholders to effectively scrutinise material provided by NSPs. It also appears that the process does not provide the AER with a clear period of time in which to assess all relevant material and make a decision, without a significant risk that NSPs will submit further information very close to the date on which a final regulatory determination is due to be made.

The Commission also recognises that, as the period for the NSPs to respond to the AER's draft regulatory determinations often falls over the Christmas and New Year period, there is a significant risk that NSPs are unable to engage adequate resources (such as consultants) to respond in a timely manner, which may then lead to some material being submitted as a submission rather than in the revised regulatory proposal. However, the time constraint does not justify NSPs submitting information beyond that required to respond to the AER's draft regulatory determination.

The Commission also considers that the nature of the regulatory determination process leading up to the AER's draft regulatory determination may influence the behaviour of NSPs after the draft regulatory determination has been made. In particular, the greater the dialogue between the AER and the NSP in the lead up to the draft regulatory determination about the likely issues that the AER will raise, the easier it should be for NSPs to respond comprehensively to the draft regulatory determination within the 30 business day period. In making this observation, the Commission recognises that limited time and resources may restrict the AER's ability to engage in greater informal dialogue.

The Commission has considered the AER's proposal. Restricting the scope of NSP submissions in the regulatory determination process may be difficult to implement if it results in inconsistencies between the NEL and NER. For instance, ETSA, CitiPower and Powercor suggest that the AER proposal may result in an inconsistency between sections 16 and 28ZC of the NEL and the NER.[456] The AER does not consider there is any inconsistency between its proposal and the NEL.[457]

It may also be that problems towards the end of the regulatory determination process could be alleviated by further engagement between the relevant NSP and the AER, either on a formal or informal basis, towards the start of it. Such engagement may address issues that the AER has raised regarding capex and opex allowances (see Chapter 3), particularly if the regulatory determination process is extended such that more time is available for the consideration of such allowances. It is important to bear in mind the links between this Chapter and Chapter 3.

456 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 35.

457 AER, Response to AEMC questions, 2 February 2012, p. 7.

### 7.2.6 Initial position

Given the broad nature of the problems that have been identified, the Commission will consider again the overall regulatory determination process with a view to achieving certain objectives, as set out below:

- the AER should have enough time to scrutinise material provided by a 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 prior to making its final regulatory determination;
- the regulatory determination process should provide a reasonable opportunity for a NSP and other stakeholders to comment on and scrutinise material submitted by each party during the regulatory determination process that is on an equal footing;
- NSPs should have sufficient time to prepare their revised regulatory proposals and should submit as much relevant information as possible in their revised regulatory proposal;
- in circumstances where a restriction is imposed on the content of the revised regulatory proposal, the NER 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.

Bearing in mind these objectives, the Commission will be considering a range of options, which are not necessarily mutually exclusive, but include:

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|---|---|
| Option 1 | Creating a new consultation step in the regulatory determination process |
| Option 2 | NSP proposal to extend the period for NSPs to submit revised regulatory proposals |
| Option 3 | Commencing the regulatory determination process earlier |
| Option 4 | Delaying the publication of the final regulatory determination until a specified number of days after the last material submission is received |
| Option 5 | AER proposal to restrict the scope of NSP submissions[458] |

Option 1 entails a submissions/cross-submissions stage, as proposed by NSPs. Or, a mandatory issues paper stage could be included, as proposed by the Victorian DPI. Currently under the NER, the publication of an issues paper is an optional stage, following the regulatory proposal.[459]

458 Section 7.2.5 of this paper discusses the AER proposal.

459 NER clauses 6.9.3(b), 6A.11.3(b).

In respect of the difficulty some NSPs have in preparing their revised regulatory proposals over the Christmas and New Year period, an option (Option 2) is to extend the current 30 business day period by an additional two weeks where it falls in this period. This option would allow for more complete revised regulatory proposals to be scrutinised by the AER and other stakeholders, however late submissions or revised regulatory proposals may not be discouraged.

Taking Options 1 and 2 together, the NSP proposal would appear to have the effect of shortening the time within which the AER must make its final regulatory determination by four weeks. Given that the AER currently has only 11 months to commence and complete the regulatory determination process, this is likely to impose a significant time restriction on the AER, making it harder for it to fully scrutinise NSP and other submissions, and make a high quality regulatory determination.

Given the overall 11 month timeframe for the regulatory determination process, the AER and other stakeholders have a limited time to participate in the process. In theory, this may place a discipline on participants to support an efficient process. However, this timeframe may not be adequate. Option 3 would extend this period by commencing the regulatory determination process earlier. Although Options 1 to 3 may improve the amount of consultation and reduce the volume of material being considered prior to the final regulatory determination, none of these options would necessarily discourage late submissions or revised regulatory proposals.

For distribution, the NER allows for some flexibility for circumstances where there is a period that intervenes between the end of one regulatory control period and the commencement of another.[460] This suggests that if there are late submissions or revised regulatory proposals which the AER and other stakeholders require further time to consider, there may be the potential for the AER to delay the making of the final regulatory determination (and the start of the next regulatory control period) to address these. Option 4 would place the onus on the NSP to decide whether the benefit of providing late submissions or revised regulatory proposals outweighs the detriment in delaying the publication of the final regulatory determination and consequently the next regulatory control period. However, this approach could also have an impact on the annual pricing proposal process (and therefore retailers, as discussed further in section 8.3), which would be delayed as a result. It may also affect the AER's overall reset timetable going forward.

### 7.2.7 Issues for further comment

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|---|---|
| **Question 35** | **What factors or principles would promote an effective regulatory determination process?** |
| **Question 36** | **Which option(s) would be the best way of addressing problems with the regulatory determination process?** |

460 NER clause 6.11.3(b); MCE SCO, *Response to stakeholder comments on the Exposure Draft of the National Electricity Rules for distribution revenue and pricing*, 1 August 2007, p. 47.

**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?**

## 7.3 NSP proposals claiming confidentiality

### 7.3.1 Context

The current confidentiality arrangements were designed to balance the need for stakeholders to have access to the information upon which regulatory decisions are made and the need to protect confidential information, the disclosure of which could commercially harm NSPs or third parties. The AER is concerned that NSPs have been claiming that more information is confidential than is necessary and that this is reducing the scope for other stakeholders to comment on and scrutinise that information. The AER proposes amendments to the NER to address this.

### 7.3.2 Current rules

Under the NER, DNSPs must indicate parts of their regulatory proposal (but not the revised regulatory proposal) they claim to be confidential and wish to have suppressed from publication on that ground.[461] The AER must publish initial and revised regulatory proposals, but is not permitted to disclose confidential information unless disclosure is permitted by the NEL and the NER.[462]

For submissions containing information that has been identified as confidential, the AER may give such weight to confidential information as it considers appropriate.[463] There is no equivalent provision in the NER with respect to confidential information in a NSP's initial and revised regulatory proposals.

Under the NEL, the AER is authorised to disclose information given to it in confidence in a number of circumstances. Some of these include:

- the person who gave the information in confidence, or the person from whom the person received that information, has given written consent to the AER to disclose that information;[464]
- the information is in a form that does not identify the person to whom that information relates eg the information is aggregated;[465]
- the confidential information is already in the public domain;[466] or

461 NER clause 6.8.2(c)(6).

462 NER clauses 6.9.3(a), 6.10.3(d), 6A.11.3(a) and 6A.12.3(f).

463 NER rule 6.14(e) and 6A.16(e).

464 NEL section 28X.

465 NEL section 28ZA.

- the disclosure of information would not cause detriment to the party to whom that information relates, or if the detriment is outweighed by the public benefit in disclosing it.[467] Disclosure under section 28ZB of the NEL is subject to a provision of notice in accordance with that clause.

Also, under common law, the AER is required to consider all information, including confidential information, that is relevant to the required considerations or factors of the administrative decision in question.[468] A failure to do so may result in adverse findings under judicial review on the grounds of considering irrelevant considerations, failure to take into account relevant considerations, or an error of law. The AER may give weight to any aspect of confidential information as it considers appropriate in all the circumstances because the NEL is silent as to how the AER can deal with confidential information in making an administrative decision.[469]

**Chapter 6A rule determination**

In the Chapter 6A rule determination, the AEMC sought to "balance the need for stakeholders to have access to the information upon which regulatory decisions are made with the need to protect confidential information that would commercially harm TNSPs or third parties (such as users)".[470] The AER previously raised the issue of TNSPs being denied the opportunity to respond to contents of a submission to which the AER must have regard.[471] The Commission agreed that ensuring regulatory determinations are subject to an open and transparent consultation process is a fundamental consideration, but was also mindful of the importance of ensuring that participants in the consultation process have access to appropriate confidentiality arrangements.[472] Therefore, the rule was made to give the AER the discretion to give such weight to confidential information in submissions as it considers appropriate, having regard to the fact that such information has not been made publicly available.[473]

**Chapter 6 considerations**

In relation to confidential information provisions during development of Chapter 6, MCE SCO stated:

> "The confidential information provisions will be elevated to the NEL, consistent with the approach taken in the NGL. The NEL (s 28V) will require the AER to consider, when it does not have the consent of the information provider to publish the information, whether to publish

466 NEL section 28ZAB.

467 NEL section 28ZB.

468 See *Minister for Aboriginal Affairs v Peko Wallsend Ltd* (1986) 162 CLR 24.

469 NEL section 18, and see also section 44AAF of the *Competition and Consumer Act 2010* (Cth).

470 AEMC, *Economic Regulation of Transmission Services*, 16 November 2006, p. 113.

471 Id., p. 121.

472 Ibid.

473 Ibid. See also NER rule 6.14(e) and 6A.16(e).

confidential information in an aggregated form, or publish the information when the AER is of the view that:

(i) the disclosure of the information would not cause detriment to the provider; or

(ii) although the disclosure of the information would cause detriment to the provider that provided it, the public benefit in disclosing it outweighs that detriment.[474]"

### 7.3.3 AER proposal

The AER considers that allowing for some information to be claimed as confidential in an initial or revised regulatory proposal given to it denies other stakeholders the opportunity to respond to, make an informed comment upon, and scrutinise all relevant information.[475] The AER is also unable to exercise its judgement and discretion in determining the weight that should be given to confidential information in an initial or revised regulatory proposal.[476] Further, the AER seeks clarification on the meaning of the term "indicate" in the context that the NSP currently has to "indicate" (as opposed to "identify") any parts of its initial regulatory proposal that it claims to be confidential.[477]

The AER proposes amendments to the NER which would:

- require NSPs to identify parts of the initial or revised regulatory proposal given to the AER that are claimed to be confidential; and
- provide the AER with the discretion to give such weight as it considers appropriate to confidential information in an initial or revised regulatory proposal. This discretion would be equivalent to the current discretion given to the AER in weighting confidential information in submissions.[478]

### 7.3.4 Submissions

NSPs do not agree with the AER's proposal and its characterisation of the problem. The following reasons were provided:

474 MCE SCO, *Changes to the National Electricity Rules to Establish a National Regulatory Framework for the Economic Regulation of Electricity Distribution*, Explanatory Material, April 2007, p. 20.

475 AER, Rule change request, Part B, 29 September 2011, p. 90.

476 Ibid.

477 Ibid.

478 Ibid.

- the NER and NEL currently provide the appropriate balance and the AER currently has sufficient discretionary powers to address confidentiality claims in initial and revised regulatory proposals;[479]
- in addition to these options, the AER has not considered other options such as a limited disclosure approach which has been used by the Australian Competition and Consumer Commission (ACCC) in the telecommunications industry;[480]
- the integrity of the regulatory determination process would be undermined if the AER can disregard or give less weight to probative and confidential information;[481]
- the AER has not provided evidence to support that it has had past problems in its ability to test the veracity of confidential information due to confidentiality restrictions or that NSPs have made excessive confidentiality claims;[482] and
- the volume of confidential information in initial and revised regulatory proposals would not reduce as a result of the AER proposal.[483]

Most of the other submissions support the AER proposal, as they agree with the AER's characterisation of the problem. However, the Victorian DPI advises that the AER should take care if it were able to give lesser weight to genuinely commercially sensitive information from NSPs.[484]

### 7.3.5 Analysis

The Commission considers that it is important that the probative value of as much of a NSP's initial or revised regulatory proposal as possible is able to be tested with stakeholders. There will almost always be information included as part of a NSP's initial or revised proposal which is legitimately claimed to be commercially sensitive and confidential. For example, if detailed cost forecasts for different aspects of a project were made public this may hamper a subsequent competitive procurement process. Such information should not be given less weight in the regulatory determination process. However, the Commission considers it unlikely that all aspects of an initial or revised regulatory proposal could legitimately be claimed to be confidential, bearing in

479 ENA, Consultation Paper submission, 8 December 2011, pp. 61-63; ENA, Consultation Paper submission, Attachment D, 8 December 2011, pp. 14-19; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 35-36, 176-179; SP AusNet, Consultation Paper submission, 8 December 2011, p. 22.

480 ENA, Consultation Paper submission, 8 December 2011, p. 62; ENA, Consultation Paper submission, Attachment D, 8 December 2011, pp. 18-19.

481 ENA, Consultation Paper submission, 8 December 2011, p. 62; ENA, Consultation Paper submission, Attachment D, 8 December 2011, pp. 15-19; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 36, 179.

482 ENA, Consultation Paper submission, Attachment D, 8 December 2011, pp. 14-16.

483 ENA, Consultation Paper submission, 8 December 2011, p. 62; Jemena, Consultation Paper submission, 8 December 2011, p. 99.

484 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 13.

mind that NSPs are monopolies and do not therefore compete directly with other businesses. There also appears to be scope for information to be aggregated where concerns about confidentiality for more detailed aspects of information are present.[485] On this basis, it would be expected that only relatively small parts of initial or revised regulatory proposals should be claimed to be commercially sensitive, and therefore confidential.

The NER does not permit the AER to give less weight to confidential information in an initial or revised regulatory proposal. However, the AER appears to have existing powers under the NEL and common law to use discretion in determining the weight to be given to confidential information in initial or revised regulatory proposals. The AER indicates that the current timeframe sometimes makes it infeasible to apply the public benefits test under section 28ZB of the NEL.[486] The AER also indicates that its internal processes are being improved upon to allow it sufficient time to make use of this discretionary power.[487] These powers may represent a possible solution to the issues raised by the AER, and if the issue is primarily that the AER has insufficient time to apply the existing powers, then it may be appropriate to consider an extension to the time period to allow the AER sufficient time to assess claims of confidentiality.

### 7.3.6 Initial position

In further considering this issue, the Commission will seek to ensure the NER provide scope for as much testing and scrutiny of initial or revised regulatory proposals as possible, while upholding legitimate claims of confidentiality by NSPs.

The Commission is seeking detailed analysis from NSPs who have submitted broad claims for confidentiality to explain why these aspects of their initial or revised regulatory proposals were confidential and whether there was scope to aggregate information to a level at which confidentiality concerns would fall away.

The Commission is also seeking examples from the AER of instances where the AER had insufficient time to consider information which was claimed by a NSP to be confidential, and where the AER had difficulty in using its current powers to address such information.

Further, views are also sought on whether the AER should be given a similar degree of flexibility to that which the Commission currently has under the rule making process under section 108 of the NEL. The Commission notes that this would be a matter for the NEL, rather than the NER.

485 Under NEL section 28ZA, information can be aggregated so as to not identify the person to whom the information relates. This could be through combining or arranging with other information provided by the NSP alone or with information from other NSPs.

486 AER, Response to AEMC questions, 2 February 2012, p. 7.

487 Ibid.

### 7.3.7 Issues for further comment

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|---|---|
| **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?** |

## 7.4 Framework and approach stage

### 7.4.1 Context

The framework and approach paper is specific to the distribution regulatory determination process as DNSPs and other stakeholders are provided with an opportunity to be consulted on the AER's likely approach for distribution service classification and incentives, as well as the AER's approach for applying form of control mechanisms. The classification of a service sets out the broad approach to regulation of that service. The control mechanism describes the way in which a distribution regulatory determination controls the price or revenue derived from a service. In respect of incentive schemes, the framework and approach paper sets out how specific schemes, such as the EBSS, will apply to a DNSP. The AER proposes changes to the content of the framework and approach paper, and when it may be departed from in a final regulatory determination.

### 7.4.2 Current rules

Prior to every distribution regulatory determination, the AER must prepare and publish a framework and approach paper.[488] This paper sets out the AER's likely approach to classifying distribution services, application of certain incentive schemes, and any other matters on which the AER thinks fit to indicate its likely approach.[489] Also, the paper has to state the form of control mechanism for each service.[490]

In respect of the classification of services set out in the framework and approach paper, this may be departed from during the regulatory determination process if there are

488 NER clause 6.8.1(a).

489 NER clause 6.8.1(b).

490 NER clause 6.8.1(c).

good reasons for doing so.[491] The AER's application of certain incentive schemes and any other matters the AER thinks fit to set out in the framework and approach paper are not binding on the AER or DNSP.[492] The control mechanisms set out in the framework and approach paper are, however, binding.[493]

Preparation and consultation on the framework and approach paper must commence at least 24 months before the end of the regulatory control period.[494] Publication of the framework and approach paper must be at least 19 months before the end of that regulatory control period.[495]

### 7.4.3 AER proposal

The AER considers that the framework and approach paper creates an inefficient three-stage consultation process on incentive schemes for distribution.[496] This inefficiency is due to limited stakeholder participation. Also, it is not binding in respect of incentive schemes, providing little benefit in the regulatory determination process and no regulatory certainty.[497]

The AER may also wish to change or include a form of control mechanism, including to reflect a change in service classification after the framework and approach paper.[498] However, it is prevented from doing so because the form of control mechanism is set out and fixed in the framework and approach paper, with no ability for the AER to change or develop a new form of control mechanism.[499] The AER also considers that there is too much scope for service classifications to be amended (ie for "good reasons") which does not provide enough investment certainty.[500]

To address its concerns, the AER proposes:[501]

- removing consultation on the application of incentives schemes in the framework and approach paper; and
- allowing the AER to change the form of control mechanism, in addition to service classification, following the framework and approach paper but only if, after the framework and approach paper is published, unforeseen circumstances arise.

491 NER clause 6.12.3(b).
492 NER clause 6.8.1(h).
493 NER clause 6.12.3(c).
494 NER clause 6.8.1(f).
495 Ibid.
496 AER, Rule change request, Part B, 29 September 2011, pp. 92-93.
497 Ibid.
498 Id., p. 93.
499 Ibid.
500 Id., pp. 93-94.
501 Id., pp. 94-95.

### 7.4.4 Submissions

**Need for framework and approach paper**

DNSPs agree that the framework and approach paper could be made more efficient, and with the need to balance flexibility and certainty of service classifications; however, they disagree with the AER's proposal.[502] They consider that greater discretion should be given to the AER and DNSPs to limit the scope of the framework and approach paper or bypass the paper.[503]

The framework and approach paper would still be necessary when an incentive mechanism is changed.[504] DNSPs would require time to prepare a regulatory proposal in response to that determination.[505] DNSPs suggest other circumstances where the framework and approach paper may be published, such as when:[506]

- no previous distribution regulatory determination applies to the NSP;
- the DNSP owns, controls or operates dual function assets (being those transmission assets owned, operated or controlled by a DNSP which provide support to the transmission network); or
- either the AER or DNSP gives notice 25 months before the end of the current regulatory control period that a control mechanism and/or service classification will materially differ from the current control mechanism and/or service classification, or that adjustment for the fair sharing of the profits from the provision of services (other than standard control services using assets forming part of the RAB between DNSP and users) may be required.

The Victorian DPI does not support the removal of consultation on the application of incentive schemes from the framework and approach paper, due to concerns with the level of engagement by stakeholders on these schemes later in the regulatory determination process.[507] Aurora Energy does not consider that the AER has demonstrated the benefit of reducing stakeholder consultation on the incentive schemes that could have large impacts on future DNSP revenues.[508]

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502 Aurora Energy, Consultation Paper submission, 15 December 2011, p. 15; Ausgrid, Consultation Paper submission, 8 December 2011, pp. 34-35; ENA, Consultation Paper submission, 8 December 2011, pp. 63-64; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 37-38, 181, 183; Jemena, Consultation Paper submission, 8 December 2011, pp. 90, 102.

503 ENA, Consultation Paper submission, 8 December 2011, pp. 63-64; Jemena, Consultation Paper submission, 8 December 2011, p. 102; SP AusNet, Consultation Paper submission, 8 December 2011, p. 22.

504 ENA, Consultation Paper submission, 8 December 2011, p. 63; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 37, 182, 184.

505 Ibid.

506 ENA, Consultation Paper submission, 8 December 2011, p. 64; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 38, 183-184.

507 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 13.

508 Aurora Energy, Consultation Paper submission, 15 December 2011, p. 15.

**Changes to form of control mechanism and/or service classification in regulatory determinations**

Ausgrid considers that the AER's proposal limits the DNSP's ability to request, and the AER's discretion to determine, to move away from the service classification and form of control mechanism set out in framework and approach paper.[509] It also considers that the AER's proposal to apply a foreseeability threshold to determine whether to depart from the service classification or form of control mechanism in the framework and approach paper would be too subjective, difficult and not achieve the correct outcomes.[510] It proposes that DNSPs have the ability to seek, and for the AER to consider, a move away from the service classifications in the framework and approach paper, and extend this also to the form of control mechanism if there are persuasive arguments or material reasons to move away.[511]

ETSA, CitiPower and Powercor agree that the AER should have some flexibility to revisit the formulaic expression of the control mechanism for each regulatory determination, which the AER has previously amended in past regulatory determinations.[512] However, they consider that the form of control mechanism that will be applied in the regulatory determination needs to be locked in prior to the lodging of the regulatory proposal.[513] Otherwise, the AER proposal would create an unacceptable degree of regulatory uncertainty for DNSPs, place a prohibitive administrative burden on DNSPs, and may constrain the DNSP's ability to properly assess any new proposed form of control mechanism.[514]

The Victorian DPI agrees with allowing the service classification and form of control mechanism to be amended after the framework and approach paper.[515]

### 7.4.5 Analysis

An analysis of submissions provided during previous framework and approach paper processes is informative as to the extent to which these are used. This analysis is set out below.

509 Ausgrid, Consultation Paper submission, 8 December 2011, p. 35.

510 Ibid.

511 Ibid.

512 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 37.

513 Ibid.

514 Ibid.

515 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 13.

**Table 7.1 Submissions provided during framework and approach paper processes**

| Jurisdiction | Year | Number of submissions | Number of submissions making specific comments on incentive schemes |
|---|---|---|---|
| Queensland | 2008 | 11 (inc 4 from DNSPs) | 2 (only from DNSPs) |
| South Australia | 2008 | 3 (inc 1 from DNSP) | 1 (only from DNSP) |
| Victoria | 2009 | 11 (inc 5 from DNSPs) | 10 (inc 4 from DNSPs) |
| Tasmania | 2010 | 7 (inc 2 from DNSP) | 4 (inc 2 from DNSP) |

This analysis suggests that there has been engagement in the framework and approach paper process, including reasonable stakeholder engagement on incentive schemes.

**Need for framework and approach paper**

In respect of whether the framework and approach paper should be discretionary, if there are no material changes to a particular component of the framework and approach paper, then the framework and approach paper should not be necessary for consultation on that particular component. This is because the consultation on that component(s) would not provide any additional benefit and certainty. This would lead to more flexibility and discretion in the regulatory determination process, as well as reduce administrative costs by making the process more efficient. The Commission seeks comments on the appropriate mechanism to be used to trigger the publication of, and consultation on, a framework and approach paper. It is noted that the ENA, ETSA, CitiPower and Powercor propose a possible mechanism in this regard, as described in section 7.4.4 above. The Commission welcomes submissions on whether stakeholders other than NSPs should have the ability to trigger a framework and approach paper, and in what circumstances.

Given that there has been reasonable stakeholder engagement on incentive schemes in the framework and approach paper process, it does not appear appropriate to eliminate these from the framework and approach paper altogether. The AER's concern with incentive schemes may be alleviated if the framework and approach paper stage is made discretionary.

**Changes to form of control mechanism and/or service classification in regulatory determinations**

In respect of changes to service classification, a trigger that would allow the AER to depart from its framework and approach paper in the event of unforeseen

circumstances appears appropriate. The approach proposed by Ausgrid, which would merely require persuasive evidence, would allow more flexibility but be less certain. It is not clear why a service classification should need to change if nothing unexpected has occurred. If a classification was set on the expectation of one set of circumstances, and then another set of circumstances came to pass (such as following a pending judicial decision), this would appear to meet the test of unforeseen circumstances.

In respect of the control mechanism, the Commission notes the strong argument presented by ETSA, CitiPower and Powercor that it would take a NSP some time to accommodate a change in control mechanism. At the same time, however, Ausgrid's approach, which favours flexibility, appears to assume that there would be sufficient time to adjust to a new control mechanism. Where unexpected circumstances occur, the AER may need the flexibility to adjust the control mechanism. In addition, the trigger for a departure from the control mechanism should, if possible, be the same as that for the service classification. Otherwise, the mismatch between the two triggers may mean an appropriate control mechanism would not be able to be set for an altered service classification. Given the approach taken to service classification, this suggests an "unforeseen circumstances" test for the control mechanism as well.

### 7.4.6 Initial position

The Commission's initial view is that the framework and approach paper stage should be optional, with the appropriate trigger to be considered further. Incentive schemes should remain part of the framework and approach paper. It may be appropriate to include in the paper the proposed sharing mechanism to allow consumers to be compensated where distribution assets are used to provide non-standard control services, which is discussed in Chapter 4 of this paper.[516]

The AER's proposal of using "unforeseen circumstances" as the trigger for allowing changes to a control mechanism or service classification set in the framework and approach paper appears to be broadly appropriate from a policy point of view. The Commission seeks submissions on this, and in particular whether any foreseeability element must be reasonable. More information is also sought on how much time it is likely to take for a NSP to adjust its regulatory proposal for a revised control mechanism set by the AER in a draft regulatory determination.

### 7.4.7 Issues for further comment

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|---|---|
| **Question 41** | **Should the framework and approach paper be a discretionary stage in the distribution regulatory determination process? If so, what is the appropriate approach to triggering it? Should stakeholders other than NSPs have the ability to trigger a framework and approach paper, and in what circumstances?** |

516 See section 4.6 of this paper which discusses this proposed sharing mechanism.

| | |
|---|---|
| **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 a NSP to accommodate an adjustment to a control mechanism in an AER draft regulatory determination?** |

## 7.5 Material errors in regulatory determinations

### 7.5.1 Context

The NER allows the AER to revoke and substitute regulatory determinations where a material error arises. Depending on whether it is a distribution or transmission regulatory determination, there are different types of material errors which allow for revocation and substitution of regulatory determinations. The AER seeks to align these differences by broadening its ability to revoke and substitute for material errors in Chapter 6 of the NER.

### 7.5.2 Current rules

Under the NER, the AER may revoke a regulatory determination during the regulatory control period to correct for material errors.[517]

For transmission, the revocation is possible when the regulatory determination is set on the basis of false or materially misleading information, or where there is a material error (although "material error" is not defined in the NER).[518] Where the AER revokes a regulatory determination, it must be substituted with a new regulatory determination, to apply for the remainder of the regulatory control period.[519] If the revocation is as the result of a material error, the substituted regulatory determination must only vary from the revoked regulatory determination to the extent necessary to correct the relevant error.[520]

For distribution, the material errors or deficiencies for which the AER may revoke and substitute a distribution regulatory determination during a regulatory control period is more prescriptive. In particular, these material errors or deficiencies relate to a clerical error, an accidental slip or omission, a material miscalculation of figure or material mistake in describing any person, thing or matter referred to, a defect in form, or the regulatory determination being based on false or misleading information provided to

517 NER rule 6.13 and 6A.15.

518 NER rule 6A.15(a).

519 NER rule 6A.15(b).

520 NER rule 6A.15(c).

the AER.[521] If the AER revokes a distribution regulatory determination, it must make a new distribution regulatory determination in substitution for the revoked regulatory determination, to apply for the remainder of the regulatory control period.[522] If it is as the result of a material error or deficiency, the substituted regulatory determination must only vary from the revoked regulatory determination to the extent necessary to correct the relevant error or deficiency.[523]

### 7.5.3 AER proposal

The AER raises three areas of concern with respect to revocation and substitution of regulatory determinations as a result of material errors:[524]

- there may be the potential for a material error that is outside the currently prescribed list for distribution regulatory determinations;
- in transmission, uncertainty is created by the power to correct material errors caused by false and misleading information as there is no express limit placed on correcting this type of error only to the extent necessary (noting though that there are provisions in crimes legislation to disincentivise the provision of false and misleading information);[525]and
- there may be circumstances in which it may be more preferable or appropriate to amend a regulatory determination, as opposed to revoking and substituting the entire regulatory determination.

To address its concerns, the AER proposes to replace the prescribed list of material errors in Chapter 6 with a more general reference to material errors or deficiencies.[526] The AER also proposes to limit changes related to false and misleading information under Chapter 6A "only to the extent necessary" (false and misleading information is already limited in Chapter 6 in this way), and expand the circumstances for revoking and substituting regulatory determinations to address deficiencies (in addition to material errors) under Chapter 6A ("deficiency" is already included in Chapter 6).[527] The AER also proposes to have the ability to amend, in addition to revoke and substitute, regulatory determinations in response to material errors.[528]

521 NER rule 6.13(a).

522 NER rule 6.13(b).

523 NER rule 6.13(c).

524 AER, Rule change request, Part B, 29 September 2011, pp. 95-96.

525 Section 137.1 of the *Criminal Code Act 1995* (Cth) and section 4B of the *Crimes Act 1914* (Cth)

526 AER, Rule change request, Part B, 29 September 2011, p. 96.

527 Ibid.

528 Ibid.

### 7.5.4 Submissions

NSPs generally agree with the alignment of Chapters 6 and 6A where it is appropriate to do so, but disagree with the AER's proposal.[529] They consider that the prescribed list of errors under Chapter 6 is not deficient, and provides certainty and finality.[530] There has been no evidence of other errors that would justify expanding this list – instead, there have been instances where the AER should have revoked and substituted regulatory determinations for material errors, but the AER did not do so.[531] Therefore, NSPs state that if there is a need for alignment between Chapters 6 and 6A of the NER, then rule 6A.15 should better reflect rule 6.13.[532]

Specific to transmission, Grid Australia agrees with limiting corrections related to false and misleading information only to the extent necessary to promote finality and certainty.[533] However, it considers the AER's proposed inclusion of the term "deficiency" expands the scope and does not provide for finality and certainty.[534] The AER's proposal in relation to revoking and substituting a regulatory determination is an attempt to align transmission and distribution.[535] Such an alignment should be taken in "full consideration of the implications [sic] such actions and the differences that already exist between the frameworks".[536]

NSPs also generally did not support including the ability for the AER to amend, in addition to the AER's current ability to revoke and substitute, regulatory determinations.[537] This is because the AER proposal for amending regulatory determinations would remove existing safeguards that are available when making a new regulatory determination (eg merits review).[538]

529 ENA, Consultation Paper submission, 8 December 2011, p. 66; Grid Australia, Consultation Paper submission, 8 December 2011, p. 78.

530 ENA, Consultation Paper submission, 8 December 2011, p. 65; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 190-191; Jemena, Consultation Paper submission, 8 December 2011, pp. 99-100, 102-103.

531 ENA, Consultation Paper submission, 8 December 2011, p. 65; ENA, Consultation Paper submission, Attachment D, 8 December 2011, pp. 23-24; Jemena, Consultation Paper submission, 8 December 2011, pp. 94-95.

532 ENA, Consultation Paper submission, 8 December 2011, p. 66.

533 Grid Australia, Consultation Paper submission, 8 December 2011, p. 79.

534 Ibid.

535 Id., p. 78.

536 Ibid.

537 ENA, Consultation Paper submission, 8 December 2011, p. 66; Grid Australia, Consultation Paper submission, 8 December 2011, p. 79; Jemena, Consultation Paper submission, 8 December 2011, p. 90.

538 ENA, Consultation Paper submission, Attachment D, 8 December 2011, pp. 24-25; Grid Australia, Consultation Paper submission, 8 December 2011, pp. 7, 77, 79.

The MEU supported the AER's proposal.[539] The Victorian DPI also supported amending regulatory determinations to correct for material errors to be consistent across distribution and transmission.[540]

### 7.5.5 Analysis

In respect of changes to regulatory determinations, the Commission is generally of the view that after the final regulatory determination is made it should only be able to be changed as a result of merits review outcomes or in very clear and exceptional circumstances. Therefore, the Commission is in favour of keeping the scope of the material error provisions narrow and focussed on "computational" errors or situations where a NSP has submitted false or misleading information. Provisions such as pass throughs, capex reopeners and contingent projects are the appropriate means by which more substantive changes to the regulatory determination should be made.

DNSPs have argued that the AER has not provided evidence of past situations where the AER was unable to revoke regulatory determinations due to the prescribed material errors list under Chapter 6.[541] Instead, DNSPs have offered evidence that the AER had opportunities to apply its discretion but chose not to do so. To consider this issue further, the Commission welcomes submissions on previous situations where the AER has been constrained from correcting regulatory determinations due to the narrower approach to material errors in Chapter 6.

There appears to be a consensus in submissions that correcting material errors in regulatory determinations caused by false and misleading information should be limited to the extent necessary. This is currently possible for distribution regulatory determinations, but is absent from transmission regulatory determinations. It therefore would be reasonable to consider aligning this aspect in Chapter 6A with Chapter 6.

The AER proposes to be able to amend, as an alternative to revoking and substituting, a regulatory determination as a result of a material error or deficiency where it is more preferable or appropriate to do so. The difference in benefits between on the one hand, amending, and on the other hand, revoking and substituting, is not very clear. However the Commission's initial view is that the power to amend regulatory determinations will impact on the NSP's ability to have this reviewed in a merits review.[542]

539 MEU, Consultation Paper submission, 8 December 2011, p. 8.

540 Victorian DPI, Consultation Paper submission, 8 December 2011, p. 13.

541 ENA, Consultation Paper submission, 8 December 2011, p. 65; ENA, Consultation Paper submission, Attachment D, 8 December 2011, pp. 23-24; Jemena, Consultation Paper submission, 8 December 2011, pp. 94-95.

542 ENA, Consultation Paper submission, Attachment D, 8 December 2011, pp. 24-25; Grid Australia, Consultation Paper submission, 8 December 2011, pp. 7, 77, 79.

### 7.5.6 Initial position

The Commission's initial view is that:

- the "only to the extent necessary" limitation should apply to false and misleading information under Chapter 6A - this would align Chapter 6A with Chapter 6 and provide certainty and finality;
- it is unclear how amending regulatory determinations would differ in practice from revoking and substituting - but the Commission agrees that this will impact unfavourably on the availability of merits reviews;
- more support is required prior to broadening the types of material errors or deficiencies under Chapter 6 by which the AER may revoke and substitute regulatory determinations; and
- it may be more appropriate for rule 6A.15 to reflect the narrow scope of material errors in rule 6.13 – this would result in more certainty and finality for the AER and NSPs, although less flexibility for the AER.

### 7.5.7 Issues for further comment

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|---|---|
| **Question 44** | **Should the material error list under Chapter 6A be amended to reflect the current prescribed list under Chapter 6 of the NER?** |
| **Question 45** | **Has the AER been constrained by the wording of Chapter 6 of the NER in its approach to revoking and substituting regulatory determinations as a result of material errors or deficiencies?** |

## 7.6 Timeframes for cost pass through, contingency projects and capex reopener applications

### 7.6.1 Context

When the AER receives an application for either cost pass throughs, contingency projects or capex reopeners, it has a set time to make its decision which varies according to the type of application (except for negative pass throughs which has no set time limit). The AER considers that it does not have enough time for more complex applications, and proposes to have the ability to extend this time to a set maximum period, as well as aligning the current decision-making periods across all types of applications.

### 7.6.2 Current rules

For distribution and transmission, the AER has 60 business days to make a decision on a positive pass through application from when it receives the application.[543] There is currently no set timeframe for the AER to make a decision on negative cost pass through applications.[544]

In addition, for transmission, the AER has:

- 30 business days to make a decision on a contingent project application from when it receives the application;[545] and
- 60 business days to make a decision on a capex reopener application from when it receives it.[546]

In distribution, the AER is required to extend the time for pass through applications if it is satisfied certain circumstances have been met.[547]

### 7.6.3 AER proposal

The AER considers that 60 business days may be adequate for a majority of pass through applications.[548] However, there may be instances where more time would be required for the AER to undertake a thorough assessment or provide for more meaningful stakeholder consultation.[549] These instances relate to applications of greater complexity and detail.[550] The AER suggests similar issues could also arise for contingent projects and capex reopener applications.[551]

To address this, the AER proposes a common default decision-making period of 40 days from the date the application is received for positive pass throughs, negative pass throughs, contingent projects and capex reopeners.[552] For complex or difficult applications or where the AER requires further information from NSPs, the AER proposes to extend this decision-making period by an additional maximum period of 60 business days.[553]

543 NER clauses 6A.7.3(e) and 6.6.1(e).
544 NER clauses 6A.7.3 and 6.6.1.
545 NER clause 6A.8.2(d).
546 NER clause 6A.7.1(c)(2).
547 NER clauses 6.6.1(k).
548 AER, Rule change request, Part B, 29 September 2011, p. 99.
549 Id, pp. 99-100.
550 Ibid.
551 Id., p. 100.
552 Ibid.
553 Ibid.

### 7.6.4 Submissions

NSPs generally agree that the current fixed timeframe for the above applications may not be sufficient in all cases.[554] However, they disagree with the proposed maximum limit of a total 100 business days due to complex applications that may require more time.[555] Instead, they propose a "stop-the-clock" mechanism whereby the AER could exclude from the timeframe such matters as the period for waiting upon information from third parties or NSPs, or the time of a relevant inquiry that would impact on the relevant pass through event.[556]

On the other hand, the MEU and Victorian DPI support the AER's proposal.[557] In contrast, UE and MG are concerned that the ability for the AER to extend its regulatory determination process would be impractical as it delays project approval and may impose significant costs on customers.[558]

### 7.6.5 Analysis

One of the principles set out in Chapter 2 is that a NSP should be able to recover its efficient costs. This should encourage overall investment. However, this needs to be balanced with the need for certainty and finality of AER decisions which is an important contributor to the incentives that make up the current framework.

NSPs have provided evidence of events where the time for making a decision on a cost past through application can be dependent on external inquiries or further information.[559] The AER, in its rule change request, referred to a decision of the Queensland Competition Authority on a cost pass through application in respect of cyclone Larry which took over 15 months from the initial application.[560] Extending the time for the AER to consider the application to a specified period for complex circumstances, as the AER proposes, may be appropriate in some applications and

554 Aurora Energy, Consultation Paper submission, 15 December 2011, p. 16; ENA, Consultation Paper submission, 8 December 2011, pp. 68-69; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 196; Grid Australia, Consultation Paper submission, 8 December 2011, pp. 80-81; Jemena, Consultation Paper submission, 8 December 2011, pp. 91, 100.

555 ENA, Consultation Paper submission, 8 December 2011, p. 68; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 40, 196-197; Grid Australia, Consultation Paper submission, 8 December 2011, pp. 80-81; Jemena, Consultation Paper submission, 8 December 2011, p. 100.

556 ENA, Consultation Paper submission, 8 December 2011, pp. 20, 68-69; ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 40, 196-197; Grid Australia, Consultation Paper submission, 8 December 2011, pp. 7, 80-81; Jemena, Consultation Paper submission, 8 December 2011, pp. 100, 103; SP AusNet, Consultation Paper submission, 8 December 2011, p. 22.

557 MEU, Consultation Paper submission, 8 December 2011, pp. 8-9; Victorian DPI, Consultation Paper submission, 8 December 2011, p. 14.

558 UE and MG, Consultation Paper submission, 8 December 2011, 9.

559 See for example ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, pp. 196.

560 AER, Rule change request, Part B, 29 September 2011, p. 100.

provide a degree of certainty and finality. However, as NSPs note, it does not account for factors that may exceed the maximum period proposed by the AER. The "stop the clock" mechanism proposed by NSPs would better cater for this risk. While this could create uncertainty as to when a decision will be made, it would promote better regulatory outcomes by ensuring that the AER has considered all the relevant and significant information.

With respect to capex reopener applications, there also appears to be merit in making amendments to the timeframes. Capex reopeners involve large events that will affect a significant proportion of the network. There is the likelihood that further information would be required and, for that reason, there may be merit in extending the "standard" timeframe for such applications via the "stop the clock" mechanism as proposed by the NSPs.

Unlike cost pass throughs and capex reopeners, however, there appears to be less likelihood of complex information requirements for contingent project applications, which are considered in advance at the time of the regulatory determination. There has not been sufficient evidence provided to support that such circumstances could arise for contingent project applications that would warrant an extension to the AER's decision-making time.

In addition to the AER and NSP proposals, the Commission is considering the possibility of addressing the time between an event taking place and when the NSP must make an application with respect to that event. This may apply in respect of pass through applications, contingent projects or capex reopeners. Analysis of cost pass through applications made to the AER in distribution to date indicates that of 11 pass through applications, the AER extended the timeframe for submission of the application for five of these. For example, the AER allowed the NSW DNSPs an additional six months to submit cost pass through applications in respect of costs associated with the sale of their respective retail businesses.[561] In respect of Cyclone Yasi, the AER granted Ergon Energy an additional 40 business days to submit an application.[562]

Another option would be to amend the NER so that NSPs could provide a notice of intent for making an application, indicating that the application is contingent on the completion of an external inquiry, or dependent on further information. This could avoid the disruption of the AER's decision-making time once an application has been made, leading to certainty and finality. However, this could depend on the definition of the event which the application is being sought for.

### 7.6.6 Initial position

The Commission's initial view is that the stop the clock mechanism should be explored further. The "stop the clock" mechanism may be appropriate for addressing complex

561 AER, *Extension of the time limit to submit cost pass through applications in respect of the sale of NSW electricity businesses*, July 2011.

562 AER, *Ergon Energy – extension of time to submit Cyclone Yasi cost pass through application*, 10 June 2011.

pass through and capex reopener applications. However, the Commission does not consider that it should also be applied to contingent project applications as it is unclear when complex circumstances could arise for these types of applications. The Commission welcomes submissions on this. Submissions are also sought on the timeframes prescribed for the period between the event and the submission of an application in respect of it, and the possibility of any other options such as a NSP providing a notice of intent for making an application.

The Commission notes that consideration of the time between an event occurring and the submission of an application to the AER in respect of it will require consideration of how an "event" is characterised. This may link to the rule change request on pass throughs, submitted by Grid Australia, which the Commission is also currently considering.[563]

### 7.6.7 Issues for further comment

| | |
|---|---|
| **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?** |

563 Grid Australia, Rule change request, 14 October 2011.

# 8 Other Issues

**Summary**

- Stakeholders in submissions have raised a range of matters which go beyond the broad scope of the rule change requests.
- The Commission summarises these issues and provides views on these matters having regard to the Commission's powers for energy market development under the NEL and the NGL.

Chapters 3 to 7 provide analysis on the main areas identified by the Commission in its Consultation Paper based on the rule change requests from the AER and the EURCC. This Chapter presents other issues raised in submissions which are beyond the scope of the rule change requests. Many of these matters are also outside the broader remit of the AEMC. Therefore this Chapter is primarily intended to summarise the issues that have been raised. It also identifies the bodies that the Commission considers primarily have responsibilities relating to those issues, and provides the Commission's views on those issues having regard to the Commission's powers and functions for energy market development under the NEL and NGL.

This Chapter covers the following:

- consumer involvement;
- AER resources;
- pricing approval process;
- merits review;
- affordability; and
- transitional issues.

## 8.1 Consumer involvement

Stakeholders have identified that more consumer engagement in the regulatory determination process would be beneficial.

### 8.1.1 Submissions

The majority of the consumer groups support changes that would allow consumer groups to more meaningfully engage in the electricity regulatory determinations

process.[564] The Consumer Action Law Centre (CALC) proposes that consumers should be engaged before the NSP makes its regulatory proposals to the AER (as opposed to afterwards), and for the AER and NSPs to be responsible for initiating this engagement process.[565]

NSPs generally agree that more consumer involvement in the regulatory determination process should be considered, and that better resourcing for consumer groups should be addressed. ENA supports consumer participation including the development of a well-funded, national centralised consumer advocacy body.[566] Jemena strongly supports better resourcing for consumer groups so they can play a more meaningful role in the regulatory determination process, have a much deeper level of understanding of regulatory issues, and provide meaningful input into the AER's decisions on consumers' behalf.[567] SP AusNet supports consumer engagement through improved resourcing to groups capable of this level of sophistication or with improved opportunities to interact in the existing regulatory determination framework.[568]

Although it is desirable to also have consumers involved in the merits review process, some submissions argue that it is difficult to do so in practice. The reasons for this include the significant information imbalance and the risks to consumer organisations of having legal costs awards made against them.[569]The difficulty for the consumer groups to fully engage in the price setting process is also identified due to the technical details required to understand the process and the cost drivers.[570]

PIAC also mentions that Rod Sims, the chairman of the ACCC, noted that the regulatory determination processes had become "increasingly technical and impenetrable to outsiders". This complexity gave rise to processes that were dominated by the well-resourced industry participants, who can effectively engage themselves or engage consultants in matters of technical detail. PIAC also submits that the scarce resources of consumer advocates and advocacy grants cannot be used in the most cost effective and efficient manner.[571]

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564 ANZEWON, Consultation Paper submission, 6 December 2011, p. 2; BCA, Consultation Paper submission, 22 December 2011, pp. 1-2; Consumer Action Law Centre, Consultation Paper submission, 9 December 2011, p. 4.

565 Consumer Action Law Centre, Consultation Paper submission, 9 December 2011, p. 4.

566 ENA, Consultation Paper submission, 8 December 2011, p. 7.

567 Jemena, Consultation Paper submission, 8 December 2011, p. 6.

568 SP AusNet, Consultation Paper submission, 8 December 2011, p. 23.

569 Consumer Action Law Centre, Consultation Paper submission, 9 December 2011, pp. 2, 4.

570 ESAA, Consultation Paper submission, 15 December 2011, p. 7.

571 PIAC, Consultation Paper submission, 8 December 2011, pp. 2-3.

### 8.1.2 Consultant's views

In his advice to the AEMC, Professor Littlechild makes a point that the potential role of consumers and users in the regulatory process for determining network price controls is an important factor that needs to be addressed. He states that:[572]

> "Regulators are increasingly taking the view that customers or users of the regulated company have an important role to play in the process of setting price controls. This is partly because customers have a better idea of their own preferences than the regulator. But also, by discussing and/or negotiating with each other, companies and customers may be able to arrive at a mutually preferable alternative to what the regulator might impose, but nonetheless not inconsistent with what the regulator might regard as acceptable. This will enable companies to 'take ownership' of the resulting plan."

In Professor Littlechild's opinion, the regulatory determination process could make greater use of the potential knowledge of consumers in the process of discussing and agreeing a price control, the related investment program, and the level of quality of service. In his opinion, greater input by consumers can be a more preferable solution to the problems raised in the proposals regarding capital expenditure, as negotiation between companies and consumers can allow the parties to arrive at a mutually preferable decision.[573]

However, Professor Littlechild recognises that it is a challenge to identify and/or encourage consumer representatives that will be able and willing to play an active role in the pricing consultation process in some sectors.[574]

### 8.1.3 Commission's views

The Commission notes that more consumer participation is generally supported by consumer groups and NSPs. This is also a major development in Great Britain and many jurisdictions in the United States.[575] The role of consumer representatives in the regulatory determination process is not a key focus of the AER and EURCC's rule change requests. Nevertheless, the Commission considers that it is important to assess whether there are opportunities to better reflect consumers' preferences in the regulatory determination process.

In Chapter 7, the Commission discusses the process for making determinations and the scope for consumers to play a greater formal role in that process. However, the Commission notes that there does not appear to be any barriers in the NER to the AER or NSPs engaging earlier and more pro-actively with consumer representatives at

572 Stephen Littlechild, Advice to the AEMC on Rule Changes, 11 January 2012, p. 11.

573 Id, pp. 3, 11

574 Id, p. 12.

575 Id, pp. 6,11.

various stages in the regulatory determination process. Further, the Commission notes there is also nothing to stop NSPs being clearer in their proposals as to why they believe the investments they are proposing are consistent with consumers' preferences.

The Commission understands that much of the engagement with consumers in regulatory processes in Great Britain occurs without a formal legal requirement for such engagement. The Commission would encourage the AER and NSPs to make use of the flexibility provided by the current rules to engage more effectively with consumer representatives. Indeed there is likely to be merit in reasonable flexibility being provided to the AER and NSPs in this regard, as the most effective form of engagement may vary depending on the type of business (electricity or gas, transmission or distribution) and the location of the NSP (e.g. rural or urban).

The Commission recognises possible constraints on consumer advocacy resources, and the potential complexities of how to effectively engage consumers in the current regulatory process. Network regulation can be resource intensive due to its highly technical and complex nature, which is evidence-based and results in voluminous material. This does not help small consumer groups or even business consumers who do not have the benefit of extensive resources and expertise compared to NSPs and the AER.

The Commission is of the view that a national energy consumer peak body should be established. Such a body would facilitate more effective consumer engagement by improving the capacity of consumers to participate in regulatory processes and the issues covered in those processes. The introduction of the National Energy Customer framework supports further the need for a national peak energy consumer body.

This is consistent with the Productivity Commission's previous recommendation for a peak national consumer body. A major benefit identified is "[h]igher quality consumer input into policy making, including through better access to the views of frontline consumer agencies".[576]

The Commission notes the relevance to the SCER's review of merits review of the submissions received by the AEMC on the ability of consumer representatives to participate in the merits review and the intended interaction between the AEMC's rule change process and that review.

## 8.2 AER resources

In the AER's rule change request, the AER submits that the detailed codification of the methodology of economic regulation in the rule has hindered its ability to effectively regulate the NSPs. By contrast, NSPs submit that if the AER had better resources it could regulate more effectively and efficiently.

576 Productivity Commission, *Review of Australia's Consumer Policy Framework*, Inquiry Report: Volume 1 – Summary, No 45, 30 April 2008, p. 62; Productivity Commission, *Review of Australia's Consumer Policy Framework*, Inquiry Report: Volume 2 – Chapters and Appendixes, No 45, 30 April 2008, pp. 257, 291.

### 8.2.1 Submissions

ENA submits that the provision of stronger AER resources and capacity would potentially provide the regulator with effective means to more completely analyse, assess and weigh information provided to it through existing regulatory information powers.[577]

ESAA also points out that stronger AER resourcing is a consideration for policymakers. Better AER resourcing would minimise the risk that the regulator could make mistakes, thus in turn reducing the resources required for appeals processes for the regulator, the industry and other stakeholders.[578]

### 8.2.2 Commission's views

The Commission has not evaluated the various views on AER resources set out in the submissions. Resourcing of the AER is a matter for the AER Board and the Commonwealth Treasury.

## 8.3 Pricing approval process

Under the current rules, a distribution network is obliged to submit its pricing proposal for the first year of a regulatory control period, for the subsequent years of that period respectively and to post its tariffs within certain timing constraints. Submissions from retailers comment that the current pricing approval process is not workable in terms of the timeliness and consultation. They propose that the Commission needs to consider expanding the scope of the rule change requests put forward by the AER to include these matters.

### 8.3.1 Submissions

The submissions on improving the pricing approval process were mainly received from retailers.[579] Origin argues that the NER do not provide retailers sufficient time to review prices, to model retail prices, and to notify increases in retail prices as required by other laws and the rules are not strictly followed. In addition, the NER do not allow retailers or other industry bodies an opportunity to respond to the proposed prices.

Origin's submission proposes the following rule changes:

- Insert rules to ensure that the AER will have finalised its decision on network revenue with a lead time of at least two months between a "draft decision" on prices and the first day the prices will apply.

577 ENA, Consultation Paper submission, 8 December 2011, p. 2.

578 ESAA, Consultation Paper submission, 15 December 2011, p. 8.

579 ERAA, Consultation Paper submission, 8 December 2011, pp. 1-2; Origin Energy, Consultation Paper submission, 8 December 2011, pp. 1, 4, 5.

- Insert a rule requiring the AER to hold a consultation period on the draft pricing decision, including:
  - one week for users to comment upon new prices; and
  - one week for the AER to consider these submissions.
- Insert a rule requiring the AER to publish the final price decision six weeks prior to the date the new prices will apply.
- Insert a rebalancing constraint to limit rebalancing in the first year of a revenue determination.
- Insert a rule such that where the result of an appeal to the Australian Competition Tribunal becomes known during the last two months before a network tariff increase it cannot be applied until the following year.[580]

### 8.3.2 Commission's views

The Commission recognises that unpredictable network price changes year to year create challenges for retailers in setting future prices, and potentially offering fixed price retail products to their consumers. However, the Commission considers the pricing approval process is outside of the scope of these rule change requests. Changes arising from problems discussed in Chapter 7 may assist to some extent, however if stakeholders consider further rule changes are required, a separate rule change request would need to be submitted.

## 8.4 Merits review

Merits reviews have been mentioned in a number of submissions, both in the context of WACC and generally. The SCER has announced the commencement of a review of the appeals mechanism in 2012.

### 8.4.1 Submissions

ETSA, Citipower and Powercor comments that convergence of the WACC determination framework for transmission and distribution is desirable in principle but should be based on Chapter 6, not Chapter 6A of the NER. It is concerned that the AER's proposed rule change would have the effect of removing the existing flexibility under Chapter 6 of the NER to respond to changes in market conditions.[581]

SP AusNet points out that its positions may change subject to the result of the review of the merits review undertaken by the SCER.[582]

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580 Origin Energy, Consultation Paper submission, 8 December 2011, p. 8

581 ETSA, CitiPower and Powercor, Consultation Paper submission, 8 December 2011, p. 105.

582 SP AusNet, Consultation Paper submission, 8 December 2011, p. 1.

Small consumer group the CALC submits that the report, "Barriers to fair network prices", argues that the merits review process should be abolished and businesses should only be able to pursue judicial review of the AER's economic regulatory decision. The CALC recognises the link between a merits review process and administrative discretion of the AER, and submits that if merits reviews remain then it would be more appropriate that the AER is granted with more discretion.[583]

Consumer Utilities Advocacy Centre (CUAC) also supports that merits review be abolished from the electricity and gas laws leaving judicial review as the only avenue to reopen a regulatory decision.[584] In addition, it submits that the AEMC should consider the interaction that any changes it makes to the rules will have with current and prospective appeals mechanisms that may emerge from the SCER review.

### 8.4.2 Commission's views

The detailed role and structure of merits review is outside the rule change process, as merits review is provided for in the NGL and NEL. This framework is being reviewed by the SCER this year. However, the Commission will have regard to the existing process for merits review in considering the proposed rule changes, and if appropriate may make observations or recommendations to SCER to ensure an effective interaction between the rules and the form of future merits review. Some specific issues related to the application of merits review to the WACC process are addressed by Chapter 5.

## 8.5 Affordability

Increases in energy prices are causing energy hardship to vulnerable groups of customers.

### 8.5.1 Submissions

Consumer groups submit that energy affordability is becoming a key concern for some vulnerable groups of customers.[585]

There have been a number of indicators which show that a growing number of residential consumers are experiencing financial difficulties in paying for their energy and are at risk of fuel poverty.[586] This includes the growing trend in electricity and gas disconnections by residential customers, the increasing number of emergency grants to cover energy costs and complaints to utility ombudsmen as well as the existence of hidden energy hardship.

583 Consumer Action Law Centre, Consultation Paper submission, 9 December 2011, p. 2.

584 CUAC, Consultation Paper submission, 23 December 2011, p. 5.

585 ACOSS, Consultation Paper submission, 8 December 2011, p. 1; ANZEWON, Consultation Paper submission, 6 December 2011, p. 1; Brotherhood of St Laurence, Consultation Paper submission, 8 December 2011, pp. 6-12; COTA Australia, Consultation Paper submission, 8 December 2011, p. 1; IPART, Consultation Paper submission, 8 December 2011, pp. 4-5.

586 Brotherhood of St Laurence, Consultation Paper submission, 8 December 2011, pp. 8-10.

### 8.5.2 Commission's views

Because government is best placed to identify and target assistance to those who need it, affordability is not a consideration of the rules. However, in the interests of all consumers achieving the most efficient cost is the primary objective for the Commission in its consideration of the rule change requests.

## 8.6 Transitional Issues

The AER considers that if the proposed rule changes are implemented, they should apply to the next round of distribution determinations in NSW and the ACT and transmission determinations in NSW and Tasmania.

However, the AER recognises number of areas in which the transitional arrangements are needed due to practical limitations in implementation. For example, the next WACC review is scheduled to be completed by 31 March 2014. The AER considers the WACC review outcomes would not be finalised until approximately one month prior to their final determinations for the DNSPs operating in NSW and the ACT as well as TransGrid and Transend. Given this, the AER considers that a number of transitional arrangements should be in place if the proposed rules are implemented.

### 8.6.1 Submissions

ActewAGL Distribution proposes that the current rules should continue to apply for the 2014 -19 ACT determination. It is concerned by the procedural unfairness caused by the uncertainty about the rules that will apply due to the timing of the proposed changes for the ACT and NSW NSPs.[587]

Ausgrid raises the similar concerns regarding uncertainty and unfairness caused by the transitional arrangements proposed by the AER. For example, Ausgrid submits that the changes proposed to the decision making framework for determining capital and operating expenditure forecasts as well as the process for determining the regulated cost of capital have caused significant uncertainty for Ausgrid in preparing its regulatory proposal for the 2014-19 distribution determination. It argues that it is disadvantaged compared to other NSPs who have full foresight of NER that they are planning towards. It submits that any changes to NER which could prejudice Ausgrid should not apply and instead the AEMC should let the current rules apply to NSW and ACT.[588]

587 ActewAGL Distribution, Consultation Paper submission, 8 December 2011, pp. 2-4.

588 Ausgrid, Consultation Paper submission, 8 December 2011, pp. 1,10, 20.

### 8.6.2 Commission's views

The Commission will consider transitional issues in making its draft rule determinations. The concerns regarding the AER's transitional arrangements will be considered at that time in the context of any rules to be made.

# Abbreviations

| | |
|---|---|
| ACCC | Australian Competition and Consumer Commission |
| ACCI | Australian Chamber of Commerce and Industry |
| ACOSS | Australian Council of Social Service |
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| ANZEWON | Australian and New Zealand Energy and Water Ombudsman Network |
| APIA | Australian Pipeline Industry Association |
| ATCO | ATCO Gas Australia |
| BCA | Business Council of Australia |
| CALC | Consumer Action Law Centre |
| CAPM | Capital Asset Pricing Model |
| COAG | Council of Australian Government |
| COTA | COTA Australia |
| CPA | Competition Principles Agreement |
| CUAC | Consumer Utilities Advocacy Centre |
| DBP | DBNGP (WA) Transmission Pty Ltd |
| DNSP | electricity distribution network service provider |
| DRP | debt risk premium |
| EBSS | efficiency benefit sharing scheme |
| ENA | Energy Networks Association |
| ERA | Economic Regulation Authority |
| ERAA | Energy Retailers Association of Australia |
| ESAA | Energy Supply Association of Australia |

| | |
|---|---|
| EUAA | Energy Users Association of Australia |
| EURCC | Energy Users Rule Change Committee |
| Expert Panel | expert panel on energy access pricing |
| FMV | Fair Market Value |
| GFC | global financial crisis |
| IPART | Independent Pricing and Regulatory Tribunal |
| MCE | Ministerial Council on Energy |
| MCE SCO | MCE Standing Committee of Officials |
| MEU | Major Energy Users Inc. |
| MRP | market risk premium |
| NEM | National Electricity Market |
| NER | National Electricity Rules |
| NGO | National Gas Objective |
| NGR | National Gas Rules |
| NSP | electricity transmission and distribution network service provider |
| PIAC | Public Interest Advocacy Centre |
| QMA | Queensland Magnesia Pty Ltd |
| QTC | Queensland Treasury Corporation |
| Queensland DEEDI | Queensland Department of Employment, Economic Development and Innovation |
| QUT CCCL | Queensland University of Technology - Credit, Commercial and Consumer Law Program |
| RAB | regulatory asset base |
| RIT-T | regulatory investment test for transmission |
| RPP | revenue and pricing principles |

| | |
|---|---|
| SA DMITRE | South Australian Department for Manufacturing, Innovation, Trade, Resources and Energy |
| SCCA | Shopping Centre Council of Australia |
| SCER | Standing Council on Energy and Resources |
| SOCC | Statement on the Cost of Capital |
| SORI | Statement of Regulatory Intent |
| SSROC | Southern Sydney Regional Organisation of Councils |
| STPIS | service target performance incentive scheme |
| TASCOSS | Tasmanian Council of Social Service |
| TEC | Total Environment Centre |
| TNSP | electricity transmission network service provider |
| Tribunal | Australian Competition Tribunal |
| UE and MG | United Energy and Multinet Gas |
| Victorian DPI | Victorian Department of Primary Industries |
| WACC | weighted average cost of capital |

# A Revenue and Pricing Principles

In addition to determining whether the rule change requests will or are likely to contribute to the achievement of the NGO or the NEO, the Commission must take into account the revenue and pricing principles (RPP) in making a rule for or with respect to transmission system revenue and pricing, distribution system revenue and pricing or regulatory economic methodologies. Where the RPP are required to be taken into account, the Commission must consider each of them and determine the weight to be given to them in its decision-making.

The Revenue and Pricing Principles for gas are:

> "(1) The revenue and pricing principles are the principles set out in subsections (2) to (7).
>
> (2) A service provider should be provided with a reasonable opportunity to recover at least the efficient costs the service provider incurs in— (a) providing reference services; and (b) complying with a regulatory obligation or requirement or making a regulatory payment.
>
> (3) A service provider should be provided with effective incentives in order to promote economic efficiency with respect to reference services the service provider provides. The economic efficiency that should be promoted includes— (a) efficient investment in, or in connection with, a pipeline with which the service provider provides reference services; and (b) the efficient provision of pipeline services; and (c) the efficient use of the pipeline.
>
> (4) Regard should be had to the capital base with respect to a pipeline adopted— (a) in any previous— (i) full access arrangement decision; or (ii) decision of a relevant Regulator under section 2 of the Gas Code; (b) in the Rules.
>
> (5) A reference tariff should allow for a return commensurate with the regulatory and commercial risks involved in providing the reference service to which that tariff relates.
>
> (6) Regard should be had to the economic costs and risks of the potential for under and over investment by a service provider in a pipeline with which the service provider provides pipeline services.
>
> (7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a pipeline with which a service provider provides pipeline services."

The Revenue and Pricing Principles for electricity are:

"(1) The revenue and pricing principles are the principles set out in subsections (2) to (7).

(2) A regulated network service provider should be provided with a reasonable opportunity to recover at least the efficient costs the operator incurs in— (a) providing direct control network services; and (b) complying with a regulatory obligation or requirement or making a regulatory payment.

(3) A regulated network service provider should be provided with effective incentives in order to promote economic efficiency with respect to direct control network services the operator provides. The economic efficiency that should be promoted includes— (a) efficient investment in a distribution system or transmission system with which the operator provides direct control network services; and (b) the efficient provision of electricity network services; and (c) the efficient use of the distribution system or transmission system with which the operator provides direct control network services.

(4) Regard should be had to the regulatory asset base with respect to a distribution system or transmission system adopted— (a) in any previous— (i) as the case requires, distribution determination or transmission determination; or (ii) determination or decision under the National Electricity Code or jurisdictional electricity legislation regulating the revenue earned, or prices charged, by a person providing services by means of that distribution system or transmission system; or (b) in the Rules.

(5) A price or charge for the provision of a direct control network service should allow for a return commensurate with the regulatory and commercial risks involved in providing the direct control network service to which that price or charge relates.

(6) Regard should be had to the economic costs and risks of the potential for under and over investment by a regulated network service provider in, as the case requires, a distribution system or transmission system with which the operator provides direct control network services.

(7) Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services."

# B Factors affecting the NGO or NEO

As set out in chapter 2, the proposed rules relate to the electricity and gas transmission and distribution services that are regulated. At a high level, the Commission's view is that investing in and operating the networks in the long term interests of consumers means that network reliability and safety standards are met at efficient long term cost. This outcome will be achieved if a number of conditions are met:

1. Demand is met at lowest total system cost
2. Efficient investment in and use of assets takes place:
    (a) Use of existing assets is optimised[589]
    (b) Network is managed to meet changing demand
    (c) Assets are replaced at the end of their useful life[590]
3. Network service providers recover efficient costs
4. Efficiency and innovation is rewarded

This appendix explains in more detail how the conditions contribute to the achievement of the NGO or NEO, and how the regulatory framework, market conditions, business specific factors such as governance and externalities such as government policy and natural disasters can affect the achievement of the respective conditions.

**1. Demand is met at lowest total system cost**

*How does this condition contribute to the NGO/NEO?*

The main purpose of electricity and gas networks is to transport electricity/gas from sources of production to sources of demand. The total cost to consumers of meeting demand in any period will be affected by a number of factors, such as the location of production sources, the location of demand centres, and the capacity and availability of each part of the network. In general, the further electricity or gas has to travel from the source to the demand, the higher will be the transportation costs. Generators' decisions on where to locate power stations can therefore have an impact on the cost of meeting demand for electricity, and therefore on productive efficiency.[591]

589 We use the term optimise in this context to refer to service providers making optimum decisions regarding the use of their assets.

590 In this context the useful life of an asset is the point up to which it can safely continue to be used to deliver the outputs expected of the asset. In some cases the useful life of an asset may be beyond the regulatory depreciation period for the asset.

591 This is less of an issue in gas, as there is little choice involved in the location of sources of production

*What factors affect this condition?*

In order to minimise the total cost of producing and transporting electricity, generators need to be able to identify the locations on the network where their output is likely to cause the least costs in being transported to demand centres, and in the case of gas-fired generators, the trade-off between the costs of gas and electricity transportation. Service providers may have a role in planning their networks effectively and publishing those plans. This factor is out of scope of the rule change requests.

Planning of the network will be determined largely by expectations of where demand will be located in the future. This will consequently affect the most efficient locations for generation. Good quality demand forecasts are therefore an important factor in improving the outcomes for customers from the network regulation process, but decisions on which major transmission and distribution projects are actually undertaken is determined by a subsequent test (the regulatory investment test for transmission (RIT-T) and the Regulatory Test for distribution) as part of an NSPs planning processes.

Table B1 summarises the main factors that affect this condition, and which are within scope and out of scope.

**Table B1 Summary of factors affecting whether demand is met at lowest total system cost**

| Factor | In scope? | Comments |
|---|---|---|
| Generators can identify where they are most required | No | Part of planning process |
| Demand forecasts accurate | Partly | Demand forecasting to inform the revenue determination process is in scope, the broader accuracy of demand forecasts for planning processes is not. |

**2. Efficient investment in and use of assets take place**

*How does this condition contribute to the NGO/NEO?*

Building sufficient assets to meet reliability and safety standards for the long term benefit of consumers is the key role that a service provider plays in achieving the NGO and NEO. Once an asset is built, optimising its use is the main way a service provider can minimise its costs, promoting productive efficiency.

(a) Use of existing assets optimised

Using the existing infrastructure to its optimal capacity means additional investment is not taking place before the full value of the existing assets has been realised. If assets

are under-utilised or replaced before the end of their useful lives, demand will not be met at efficient long term cost.[592]

(b) Network is managed to meet changing demand

Demand for gas and electricity is changing constantly. New houses, shops and factories are connected each day, and the increased use of technology and appliances in homes and businesses means demand (for electricity in particular) has been growing steadily for a number of years.[593] In order to meet reliability and safety standards, service providers must ensure gas and electricity can flow to new consumers and there is sufficient capacity to transport the higher levels of energy required by existing consumers. They can do this by building new infrastructure, expanding existing infrastructure or finding ways to efficiently manage levels of demand so that network infrastructure does not need to be built or expanded.

(c) Assets are replaced at the end of their useful life

Network assets such as pipes and wires eventually become unfit for use and can no longer safely transport gas/electricity without excessive maintenance costs. In order to (a) prevent dangerous over-use of assets and (b) maintain supplies to consumers at the end of the pipes and wires, old assets need to be replaced. In practice, they must be replaced shortly before they are no longer usable, to ensure continuity of supply.

In practice, a service provider will need to manage its network to meet reliability and safety standards on a dynamic basis. Within the constraints of available funding, it will need to make decisions on a holistic basis about maintenance of existing assets, investment in new assets and other options such as demand side management. Network businesses compete for funding with other businesses in Australia and abroad so that the rate of return needs to be sufficient on a risk adjusted basis to attract funding to the sector to allow investment to take place.

**What factors affect these conditions?**

The incentives applied through the regulatory framework set out in the NER and NGR will be an important determinant of how efficiently service providers invest in and maintain their infrastructure. A number of factors within the regulatory framework will affect whether use of existing assets is optimised, new assets are built to meet changing demand and assets are replaced at the end of their useful life. However, the performance of network businesses will also be impacted by the incentives placed on the management by stakeholders and, in particular, how well these are aligned with the incentives provided by the regulatory regime. As part of this, the shareholders and management of service providers will be conscious of the reputational risk they face from failing to safely maintain, and invest in their network.

592 In this context use of infrastructure to its full capacity means using it within safe operating limits, within the context of maintaining a safe operating environment.

593 However, there is evidence that demand for electricity has stopped rising over the past year or so in some states due to rising prices and energy efficiency measures

While service providers face a number of constraints in making efficient investment and network management decisions, the incentives applied through the regulatory framework set out in the NER and NGR will be a key determinant of how efficiently service providers invest in and maintain their infrastructure. A number of factors within the regulatory framework will affect whether use of existing assets is optimised, new assets are built to meet changing demand and assets are replaced at the end of their useful life. In addition to the regulatory framework, the shareholders and management of service providers will be conscious of the reputational risk they face from failing to safely maintain and invest in their network. This section describes the main factors that affect these conditions, and which are within scope and out of scope.

Service providers need an incentive to use each of their assets to its optimal capacity during its useful life. This requires a charging structure to be in place for use of the assets which reflects the costs of using those assets. Cost-reflective charges would mean that network users utilise the network assets whenever they are willing to pay the costs of doing so. If prices were above cost, there would be times when the asset was not used even though some users may be willing to cover the costs of doing so. Developing efficient network charging structures is often challenging given that the costs of operating networks do not vary significantly with the volume of throughput. Cost-reflective charging is out of scope of the rule change requests.

The incentive for service providers to invest in new assets, and to replace assets at the end of their useful life, will be determined by the reward available - i.e. the expected return on the investment. In order to invest in new assets, service providers need to be confident that they will make a return on their investment. In the long term capital will be provided only if the investment offers an attractive return compared to other potential investments. Notwithstanding there may in practice be constraints in gaining access to capital, where the rate of return allowed on a service provider's investment is higher than the cost at which it can access capital, it will be profitable for the service provider to invest in new or replacement assets. Setting an appropriate rate of return is within scope of the rule change requests.

Decisions on when and how much to invest will also be influenced by the penalty for failing to meet demand (or reliability standards). While building new assets will incur a cost (at least in the short term), failing to build sufficient assets will also result in a cost to the service provider, in the form of a penalty payment. To be effective, the regulatory framework needs to have appropriate penalty regimes. As reliability standards are determined at state level, the penalties currently differ in each jurisdiction (and between transmission and distribution). The penalties for not meeting demand are out of scope of the rule change requests.

Where demand is nearing the capacity of a particular part of the network, a service provider will have a number of options to continue to accommodate the demand. Investing in new capital assets (e.g. new wires or pipes) is just one option. In many circumstances, other options may include expanding the capacity of existing lines, increasing compression capability (in gas), or contracting with some consumers to reduce their demand (demand-side measures). Similarly, service providers will have options when an asset is nearing the end of its useful life. In deciding which option is

most cost-effective, they will need to trade off higher cost, long term solutions with lower cost, shorter term solutions. The relative returns available for each type of expenditure will ultimately determine those decisions. In order to ensure new assets are built when it is efficient to do so (rather than, for example temporarily increasing the capacity of a line in the case of electricity), it is therefore important that the regulatory framework sets rates of return for capital expenditure (capex) and operating expenditure (opex) which reflect the relative risks and values of either type of expenditure.

In order to optimise the use of an asset, service providers should undertake operational expenditure to maintain the asset - but only where this is cheaper in the long term than building a new asset. Where the allowed returns on opex and capex are appropriate, they will have an incentive to make the decision which leads to lowest costs in the long term. Setting appropriate capex and opex incentives is within scope of the rule change requests.

While a service provider will need to be flexible to adapt to unexpected changes in demand, good forecasts of demand also help a service provider to optimise the use of an asset, for example by enabling an appropriately-sized asset to be built in the first place. A decision on when to invest in new network assets will largely depend on future projections of demand in the relevant area of the network. Making high quality demand forecasts can be challenging given the range of factors that influence demand decisions. There is emerging evidence in Australia that the previous trend of demand growing broadly in line with economic growth may no longer be the case.[594] The accuracy of demand forecasts is out of scope of the rule change requests.

The expected return from an investment will be impacted by the certainty and transparency of the regulation which sets that allowed level of return. Network assets have a useful life of many years, and service providers will need to have confidence in the returns they can earn over the life of the asset. Uncertainty creates risk, which will lead service providers to require a higher rate of return in order to invest, and is likely to deter potential future investors. While returns will depend on a number of variables and cannot be forecast perfectly, investors need to know what the variables are so that they can estimate what the risks are and the value of those risks, and employ measures to mitigate those risks. Certainty and transparency for investors are within scope of the rule change requests.

Some risks to the profitability of an investment will come from external sources, over which service providers have little or no control and which they have little or no ability to mitigate. Extreme weather events and other acts of God are not easily insurable, for example. Investors are unlikely to be attracted to the sector if the risk from such events is higher than in other comparable sectors. It can be argued that the level of the allowed rate of return on investment should take account of all types of risk to the business, but in practice it is unlikely to be possible to incorporate all such risks into a single number. Compensation arrangements and other elements of the regulatory

594 See for example IPART, *Research Report - Residential energy and water use in Sydney, the Blue Mountains and Illawarra - Results from the 2010 household survey*, December 2010.

framework should allow for the risks to be appropriately shared between businesses and consumers.[595] The treatment of risks from external events is within scope of the rule changes requests.

In order for service providers to optimise the use of their existing assets, the regulatory framework needs to provide service providers with an appropriate return for the entire useful life of each asset. Under the current framework, the incentive on a service provider to optimise the use of its existing assets would be optimal if a rate of depreciation is assigned to each asset which reflects the true value and lifespan of that asset. If the rate of depreciation is too high, the service provider would stop earning a return on the asset before the end of its useful life. It would then be more likely to build a new asset on which it could earn a return, leaving the existing asset under-utilised. Alternatively, if the rate of depreciation is too low, consumers would be paying for a return on an asset when it is no longer in use. Service providers would then have a lower incentive to spend money in replacing the asset. Although in practice the value of some assets is likely to depreciate at an uneven rate over time - for example, gas tends to be withdrawn from gas fields at a higher rate in earlier years and more slowly as the pressure in the field falls - it is usually not possible to predict the profile of depreciation very accurately. Consequently a linear rate of depreciation is most commonly applied. Setting an accurate rate of depreciation is out of scope of the rule change requests.

Table B2 summarises the main factors that affect these conditions, and which are within scope and out of scope.

595 This issue is being considered further for electricity in the rule change request "Cost pass through arrangements for network service providers".

**Table B2 Summary of factors affecting efficient investment in and use of assets**

| Factor | In Scope? | Comments |
|---|---|---|
| Cost-reflective charges | No | Power of Choice review considering this[596] |
| Allowed rate of return reflects efficient financing costs | Yes | |
| Penalties for not meeting demand appropriate | No | Distribution reliability standards review will consider some related issues[597] |
| Capex and opex incentives appropriate | Yes | Strength of capex incentive in scope - also affects balance of opex and capex |
| Demand forecasts accurate | Partly | Demand forecasting to inform the revenue determination process is in scope; the broader accuracy of demand forecasts for planning processes is not. |
| Certainty and transparency for investors | Yes | |
| Risk from external events appropriately shared | Yes | Cost pass through rule change also considering this issue[598] |
| Rate of depreciation accurate | No | Whether actual or forecast depreciation is used in establishing the RAB is a separate issue, which is within scope. |

**3. Network service providers recover efficient costs**

*How does this condition contribute to the NGO/NEO?*

In trying to attract investment in their businesses, service providers are competing for funds with other possible forms of investment, both in Australia and overseas. While gas and electricity networks are traditionally seen as stable, low-risk sectors, investors still need to expect to make an efficient, risk adjusted return on their investments. In order to promote investment in gas and electricity networks, therefore, service providers must be allowed to recover the costs of owning and operating their networks.

596 http://www.aemc.gov.au/Market-Reviews/Open/Stage-3-Demand-Side-Participation-Review-Facilitating-consumer-choices-and-energy-efficiency.html

597 http://www.aemc.gov.au/Market-Reviews/Open/Review-of-distribution-reliability-outcomes-and-standards.html

598 http://www.aemc.gov.au/Electricity/Rule-changes/Open/Cost-pass-through-arrangements-for-network-service-providers.html

However, the NGO and NEO specify the promotion of *efficient* investment. If service providers are allowed to automatically recover all costs they incur, they will have no incentive to keep those costs down. As set out in section 2.2 above, regulation is intended to achieve similar outcomes to competition for the network monopoly businesses. In a competitive environment, service providers would need to minimise their costs in order to keep their prices competitive. Consequently, regulation should only allow for an "efficient" level of costs to be recovered by service providers (including a reasonable profit), rather than allowing an automatic pass-through of all expenditure. Keeping prices to consumers close to long term costs of production promotes allocative efficiency.

*What factors affect this condition?*

The main determinant of how much service providers recover is the allowed rate of return on investment. The rate of return should trade off providing sufficient return to service providers so that investment is profitable while minimising the cost for consumers. It will do this if it reflects the efficient cost of obtaining finance so that the return on every dollar invested is equal to the costs.

External events such as extreme weather events can cause substantial costs for service providers and put at risk their ability to meet reliability standards. While such events are beyond the control of service providers, and may not be fully insurable, allowing service providers to automatically recover those costs would remove any incentive to seek ways to mitigate the impacts from those events on their network. In a competitive market, it is likely that events which affect a large area would create some costs for all providers, which they can pass onto consumers. But providers will also look at ways they can minimise the costs of external risks, as a way of attracting customers. The regulatory framework should therefore allow for an appropriate sharing of risk from external events between consumers and service providers.

Costs are efficient if they are lower than the value of the benefit they provide. In the case of network investment, the benefit provided is increased reliability of gas or electricity supply. Investment should therefore only take place up to the point where the costs are equal to consumers' value of reliability. While identifying this value would help to ensure efficient costs are recovered, in practice this is unlikely to be achieved with any precision as no practical way of accurately assessing all consumers' value of reliability, and tailoring reliability on a meshed network to meet individual preferences, has yet been identified. Identification of the value of customer reliability is out of scope of the rule change requests.

Table B3 summarises the main factors that affect this condition, and which are within scope and out of scope.

**Table B3 Summary of factors affecting whether service providers recover efficient costs**

| Factor | In scope? | Comments |
|---|---|---|
| Allowed rate of return reflects efficient financing costs | Yes | |
| Risk from external events appropriately shared | Yes | Cost pass-through rule change considering this issue |
| Consumer value of reliability known | No | Distribution reliability standards review will consider this issue |

**4. Efficiency and innovation is rewarded**

*How does this condition contribute to the NGO/NEO*

In addition to providing services at the efficient cost level, businesses in competitive markets have an incentive to try to bring down the level of that efficient cost in the long term by introducing new technologies and methods of providing the service. If they can do this ahead of their rivals, they will be able to make additional profits and/or win more customers by offering lower prices. Reducing over time the level of efficient cost at which network services can be provided promotes dynamic efficiency and is in the long term interests of consumers with respect to price.

However, innovating and using new methods and technologies involves costs and risks. A service provider is only likely to incur such costs and risks if it expects to receive additional rewards in the event it is able to reduce its level of costs.

*What factors affect this condition?*

As described in chapter 2, in a competitive market those companies that can provide a service at lowest cost will earn the highest returns, or gain the highest market share. In order to incentivise service providers to seek efficiencies and innovations, the regulatory framework should allow the service providers to keep a share of any cost-savings they make. There should be a positive relationship between efficiency and reward. The level of reward for efficient companies is within scope of the rule change requests.

Similarly, companies in a competitive environment who are able to innovate and provide products that consumers value will be able to make additional profits, at least in the short term. Service providers should therefore be able to keep a share of any additional income they generate from innovative products and services until those products and services become commonplace. Equally, service providers should bear at least a share of the costs and risks involved in innovation, so that any such costs are prudently incurred. Setting the risks and rewards of innovation is within scope of the rule change requests.

The extent to which service providers innovate and seek efficiencies will depend partly on their ability and incentive to consider a range of alternative options for meeting demand. Building a new pipe and reinforcing an existing line may be standard ways of meeting additional demand, but other options may be available (such as demand side measures) which could achieve the same standard of reliability at lower cost. The relative rewards available for different options should reflect their relative costs and value to consumers. Whilst we note that the ability of the AER to consider alternative options in assessing service providers' investment proposals is potentially within scope of the rule change requests, the RIT-T and regulatory investment test for distribution are the mechanisms through which service providers consider the range of investment options. This factor is therefore out of scope of the rule change requests.

Incentives for service providers to minimise efficient costs, including through innovation is clearly a relevant consideration within the scope of the rule change requests. Indeed service providers striving for efficiency and productivity gains has been a key aspect of incentive based regulation. However, some countries and regulators have recently introduced broader policies to promote innovation, often in the context of achieving wider environmental objectives, such as Ofgem's Low Carbon Network Fund. Such approaches are not in the AEMC's view within the scope of these rule change requests.

Table B4 summarises the main factors that affect this condition, and which are within scope and out of scope.

**Table B4 Summary of factors affecting whether efficiency and innovation is rewarded**

| Factor | In scope? | Comments |
|---|---|---|
| Efficient businesses earn highest rewards | Yes | |
| Businesses bear risk and rewards of innovation | Yes | Sharing assets for use of other services is a form of innovation |
| Businesses consider all investment options | No | RIT-T and regulatory test for distribution are main mechanisms |

# C Examples of building block revenue components

Below are examples of the revenue components that go into the building block revenue requirements of NSPs and gas service providers. The data has been extracted from various AER decisions and where applicable, the allowances have been adjusted following the Australian Competition Tribunal decisions.[599] Most notably, the data shows that the greatest contribution to the revenue requirements of NSPs and gas service providers comes from the return on capital allowance. In all cases of the NSPs and gas service providers represented below, over 50 per cent of their revenue requirement is made up of the return on capital allowance determined by the AER.

**Figure C.1 ENERGEX 2010-11 to 2014-15 distribution determination (Tribunal adjusted)**

| | 2010-11 | 2011-12 | 2012-13 | 2013-14 | 2014-15 | Total | % of Total |
|---|---|---|---|---|---|---|---|
| Regulatory depreciation | 78.5 | 87.2 | 98.1 | 110.3 | 111.6 | **485.7** | 7% |
| Return on capital | 764.5 | 873.6 | 987.3 | 1,101.2 | 1,213.9 | **4,940.5** | 68% |
| Opex | 326.6 | 336.7 | 354.7 | 372.5 | 377.5 | **1,768.0** | 24% |
| Tax allowance | 80.6 | 87.4 | 96.0 | 105.9 | 113.5 | **483.4** | 7% |
| Capital contribitions | - 65.1 | - 69.1 | - 71.5 | - 74.2 | - 76.4 | **- 356.3** | -5% |
| Revenue from shared assets | - 4.0 | - 4.7 | - 5.5 | - 6.1 | - 5.7 | **- 26.0** | 0% |
| **Annual revenue requirements ($ million)** | **1,181.1** | **1,311.1** | **1,459.1** | **1,609.6** | **1,734.4** | **7,295.3** | 100% |

Source: Australian Competition Tribunal Order - *ENERGEX Distribution Determination 2010-11 to 2014-15*, 19 May 2011, Tables 16.10 and 21.

**Figure C.2 CitiPower 2011-2015 distribution determination (not adjusted for Tribunal decision)**

| | 2011 | 2012 | 2013 | 2014 | 2015 | Total | % of Total |
|---|---|---|---|---|---|---|---|
| Regulatory depreciation | 34.7 | 38.4 | 42.3 | 46.5 | 51.8 | **213.7** | 18% |
| Return on capital | 121.0 | 132.3 | 143.5 | 156.3 | 168.9 | **722.0** | 61% |
| Opex | 46.3 | 47.6 | 50.1 | 50.8 | 53.3 | **248.1** | 21% |
| Tax allowance | 6.3 | 6.7 | 7.4 | 7.7 | 8.4 | **36.5** | 3% |
| S factor amounts | - 2.2 | - 4.7 | - 3.6 | - 0.4 | - 4.0 | **- 14.9** | -1% |
| EBSS c/o amounts | 4.5 | - 8.4 | - 6.2 | - 5.5 | - | **- 15.6** | -1% |
| **Annual revenue requirements ($ million)** | **210.6** | **211.9** | **233.5** | **255.4** | **278.4** | **1,189.8** | 100% |

Source: AER, *Final Decision - Victorian electricity distribution network service providers Distribution Determination 2011-2015*, October 2010, Table 37.

**Figure C.3 Ausgrid 2009-10 to 2013-14 distribution determination (Tribunal adjusted)**

| | 2009-10 | 2010-11 | 2011-12 | 2012-13 | 2013-14 | Total | % of Total |
|---|---|---|---|---|---|---|---|
| Regulatory depreciation | 76.0 | 99.6 | 120.2 | 142.6 | 138.7 | **577.1** | 7% |
| Return on capital | 731.3 | 845.2 | 973.7 | 1,117.2 | 1,256.4 | **4,923.8** | 58% |
| Opex | 483.9 | 507.2 | 531.7 | 555.5 | 571.6 | **2,649.9** | 31% |
| Tax allowance | 39.3 | 67.5 | 77.1 | 87.7 | 92.7 | **364.3** | 4% |
| **Annual revenue requirements ($ million)** | **1,330.5** | **1,519.5** | **1,702.7** | **1,903.0** | **2,059.4** | **8,515.1** | 100% |

Source: AER, *Statement on updates for NSW DNSPs Distribution Determination 2009-10 to 2013-14*, March 2010, Table 22.

599 Note that the figures may not add due to rounding.

## Figure C.4 Powerlink 2012-13 to 2016-17 transmission determination (draft regulatory determination)

| | 2012-13 | 2013-14 | 2014-15 | 2015-16 | 2016-17 | Total | % of Total |
|---|---|---|---|---|---|---|---|
| Regulatory depreciation | 40.9 | 62.8 | 76.7 | 73.8 | 83.8 | **338.0** | 7% |
| Return on capital | 546.7 | 590.2 | 627.4 | 669.0 | 708.8 | **3,142.1** | 69% |
| Opex | 184.5 | 193.1 | 201.1 | 211.3 | 222.3 | **1,012.3** | 22% |
| Tax allowance | 15.0 | 15.9 | 18.3 | 18.7 | 20.4 | **88.3** | 2% |
| EBSS c/o amounts | - 4.2 | - 0.4 | - 3.2 | 3.9 | - | - **3.9** | 0% |
| **Annual revenue requirements ($ million)** | **782.9** | **861.6** | **920.3** | **976.7** | **1,035.3** | **4,576.8** | 100% |

Source: AER, *Draft Decision - Powerlink transmission determination 2012-13 to 2016-17*, November 2011, Table 1.2.

## Figure C.5 Jemena 2010/11 to 2014/15 NSW gas distribution networks access arrangement (Tribunal adjusted)

| | 2010-11 | 2011-12 | 2012-13 | 2013-14 | 2014-15 | Total | % of Total |
|---|---|---|---|---|---|---|---|
| Regulatory depreciation | 11.7 | 25.0 | 30.3 | 36.7 | 43.5 | **147.2** | 7% |
| Return on capital | 242.6 | 249.6 | 254.6 | 259.8 | 265.8 | **1,272.4** | 57% |
| Opex | 132.5 | 136.9 | 141.3 | 144.5 | 147.6 | **702.8** | 32% |
| Tax allowance | 12.9 | 17.7 | 19.2 | 22.2 | 25.3 | **97.3** | 4% |
| **Annual revenue requirements ($ million)** | **399.7** | **429.2** | **445.4** | **463.2** | **482.2** | **2,219.7** | 100% |

Source: JGN's NSW gas distribution networks *Access Arrangement 1 July 2010 - 30 June 2015 amended by order of the Australian Competition Tribunal*, 30 June 2011, Table 9-1.

## Figure C.6 Envestra 2010/11 to 2015/16 SA gas distribution networks access arrangement (Tribunal adjusted)

| | 2011-12 | 2012-13 | 2013-14 | 2014-15 | 2015-16 | Total | % of Total |
|---|---|---|---|---|---|---|---|
| Regulatory depreciation | 1.2 | 12.7 | 14.2 | 16.2 | 16.2 | **60.5** | 5% |
| Return on capital | 105.3 | 116.0 | 126.3 | 135.9 | 146.0 | **629.5** | 56% |
| Opex | 70.9 | 71.6 | 72.7 | 72.9 | 72.1 | **360.2** | 32% |
| Tax allowance | 11.2 | 11.7 | 11.4 | 10.9 | 10.4 | **55.6** | 5% |
| EBSS c/o amounts | 10.2 | 1.8 | 1.1 | - 0.3 | - | **12.8** | 1% |
| **Annual revenue requirements ($ million)** | **198.8** | **213.8** | **225.7** | **235.6** | **244.7** | **1,118.6** | 100% |

Source: Australian Competition Tribunal Order - *Envestra, Annexure A (Part 2)*, 10 February 2012, Table 9.1.