Australian Competition & Consumer Commission

Discussion Paper

2003

Review of the

Draft Statement of Principles for the Regulation of Transmission Revenues

Australian Competition and Consumer Commission

Contents

Abbreviations

ABS	Australian Bureau of Statistics
AGSM	Australian Graduate School of Management
βa	Asset Beta
BCA	Business Council of Australia
βd	Debt Beta
βe	Equity Beta
CAPM	capital asset pricing model
COAG	Council of Australian Governments
Code	National Electricity Code
Commission	Australian Competition and Consumer Commission
CPI	consumer price index
DAC	depreciated actual cost of an asset
DORC	depreciated optimised replacement cost of an asset
DRP	Draft Statement of Principles for the Regulation of Transmission Revenues
ESC	Essential Services Commission
ESI	electricity supply industry
ESCOSA	Essential Services Commission of South Australia
EUG	Energy Users Group
Gas Code	National Third Party Access Gas Code
IC	Industry Commission
IPART	Independent Pricing and Regulatory Tribunal, New South Wales
MAR	Maximum allowed revenue
MEE	modern engineering equivalent
MRP	market risk premium
NEC	National Electricity Code
NECA	National Electricity Code Administrator
NECG	Network Economics Consulting Group
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NPV	Net Present Value
ODRC	optimised depreciated replacement cost of an asset
ODV	optimised deprival value of an asset
ORC	optimised replacement cost of an asset
RAB	regulatory asset base
RC	replacement cost
Rf	risk free rate
RPI	retail price index
TFP	total factor productivity
TNSP	transmission network service providers / owners
TPA	Trade Practices Act 1974
WACC	weighted average cost of capital
WDV	written down value

Executive Summary

The Australian Competition and Consumer Commission (Commission) has assumed responsibility for the regulation of transmission revenue in the National Electricity Market (NEM), on a progressive basis, since 1 July 1999. The Commission's power to perform this regulatory role stems from Part IIIA of the Trade Practices Act 1974 (TPA). The National Electricity Code (Code) prescribes the broad form of regulation to be applied to the Transmission Network Service Providers' (TNSPs') revenues. It also grants the Commission the flexibility to use alternate methodologies providing they are consistent with the Code's objectives, principles, broad forms and mechanisms and information disclosure requirement.

The Code requires the Commission to publish a *Statement of Regulatory Intent* which establishes guidelines as to how it will exercise its regulatory powers. The Commission released its Draft Regulatory Principles (DRP) for the regulation of transmission revenues in May 1999. In developing the DRP the Commission drew heavily on Chapter 6 of the Code, in particular the principles and objectives espoused in section 6.2.

The Commission is now reviewing the DRP. The review of the DRP is being conducted now as the Commission has had four years of experience in regulating TNSPs' revenues. This review aims to assess the operation of the DRP and provide all interested parties with an opportunity to influence the future development of the Commission's *Statement of Regulatory Principles*.

The *Statement of Regulatory Principles* is not legally binding and it must be accepted that, in line with achieving best practice regulation, the Commission's position on some issues may change. The Commission expects that the *Statement of Regulatory Principles* will evolve in response to improvements in regulatory models and best practice regulation worldwide.

Issues covered in this discussion paper

For each issue outlined in the executive summary the Commission discusses a number of options and states its preferred position. The Commission invites submissions on the issues raised in this review. The Commission asks that those making submissions explain how their preferred approaches meet the principles and objectives set out in sections 6.2.2 and 6.2.3 of the Code (see Box 1) or other relevant parts of the Code. Details of where to send submissions and when they must be received are provided below.

<u>*Revenue Cap Decision Making Process*</u>

The Commission has found the current 6 month regulatory review period inadequate, in all 5 previous revenue cap decisions. The Commission proposes to extend the regulatory review period to facilitate consultation at all stages of the regulatory review process.

The Commission's preferred position

The Commission proposes to extend the regulatory review period to twelve months.

Revaluation of the asset base versus the merits of roll-forward

In finalising the *Statement of Regulatory Principles* the Commission will need to consider its approach to treating assets in the next revenue re-sets. For all first round revenue caps the Code stipulated the Commission adopt the state regulators valuations of TNSP's asset base value. For the second revenue reset the Code provides for the Commission to revalue the asset base. Nevertheless, the Commission does not have unlimited discretion in determining an asset valuation methodology, as the Code requires the Commission to satisfy a number of principles and objectives.

The Commission believes that there are three main options for considering future reviews.

Option 1 – Periodic revaluation of the asset base

The Commission would revalue assets on a periodic basis (for example each five-year regulatory period) using the Depreciated Optimised Replacement Cost (DORC) methodology. Revaluing the asset base could achieve allocative efficiency in as much as that the regulated tariffs are not set at a level that is inconsistent with competitive market outcomes. In addition, re-valuing the asset base could provide a useful transitional tool from the change of regulatory regimes. If the Commission is not entirely confident of jurisdictional asset values it could re-value at the initial re-set to avoid errors being perpetuated into the future. Finally, re-valuing the asset base of a TNSP could address the potential for over capitalisation.

However, this option generates a high level of uncertainty for the TNSPs and there is a strong possibility it could deter new investment. If the Commission considered revaluing the asset base on a periodic basis, the TNSP might face an unpredictable revenue stream. Volatility of revenue increases the value of the "option to wait" and thus, all else equal slows the rate of new investment. In addition to deterring investment, there is a possibility that the TNSP might lose some value of its capital expenditure. Given the risk that the TNSP might not be compensated for all of its capital expenditure, this might result in the TNSP reducing its capital expenditure. Finally, if the Commission revalues the asset base and implements the regulatory test to augmentations and non-augmentations capex to ensure efficient investment is rolled into the asset base it might be considered too heavy handed.

Option 2 – Lock-in the jurisdictional asset base

In the gas Code the rate base is determined for each regulatory period by adopting the initial jurisdictional valuation and adding in new investment at cost. This option provides a lock-in of the jurisdictional asset base is unlikely to deter new investment. In addition, a lock-in avoids the subjectivity inherent in DORC valuations.

The main problem with this option is that any errors in the jurisdictional asset base would be perpetuated into the future if the existing asset bases are inappropriate (to the extent that they do not generate efficient returns).

Options 3 – One off revaluation of the jurisdictional asset base and then lock-in

The third option being considered is a one off revaluation of the jurisdictional asset base using DORC, however, in subsequent regulatory periods the Commission will simply roll in new investment at cost. The main reason for a one off revaluation of the jurisdictional asset base would be if the Commission considered that the initial asset base was inappropriate.

The Commission's preferred position

The Commission's initial view is to consider each revenue cap on a case by case basis but with the preferred position to lock-in at this stage, as there is no evidence to suggest that there are significant problems with the jurisdictional valuations. The Commission notes that the asset base includes both fixed assets and easements.

The Commission's preferred position is to lock-in the asset base but if option 1 or 3 is adopted a number of questions are raised in regard to the implementation of DORC and the valuation of easements. The issue of easements is discussed in section 3 of the discussion paper.

<u>Capital Expenditure</u>

Capital expenditure (capex) is one of the biggest drivers of a TNSPs' revenue. The code is non-prescriptive in regard to how, methodologically, new or proposed capex should be reflected in the regulatory asset base. However, revenue caps will accommodate new investment if proposed capex programs satisfy the regulatory test, which is the mechanism set out in the code to assess the economic efficiency of investments decisions in regard to augmentations of the network.

The Commission proposes that the regulatory test apply to both augmentation and non-augmentation capex. The Commission cannot compel TNSPs to apply such a test during the regulatory control period. However, the Commission considers that if a TNSP is aware of the criteria that the Commission would employ to assess capex for the purpose of rolling it into the regulatory asset base then it the TNSP would adopt a similar criteria.

The Commission proposes that when assessing revenue proposals associated with new capex programs, it will assess the likelihood of whether or not it will pass the regulatory test. In addition, the Commission proposes at each regulatory reset to review on whether the regulatory test applications were conducted in accordance with the process and methodology outlined in the regulatory test.

The Commission's preferred position

The Commission's preferred position is to adopt the regulatory test when assessing and reviewing revenue proposals associated with augmentation and non-augmentation capex programs.

Operating and Maintenance Expenditure

In setting the TNSP's revenue requirement, the Commission needs to make informed decisions on whether or not the TNSP is acting efficiently to achieve the lowest sustainable cost of delivering electricity.

In relation to ensuring that the TNSP achieves the lowest sustainable cost the Commission is considering a number of options. The first option is the Commission's current approach. The Commission currently receives a proposal from the service provider of its forecasted actual costs. The Commission then uses a combination of performance indicators to assess the efficiency of the firm's costs such as historical performance and forward-looking assessment of cost drivers. The Commission appoints a consultant who inturn assesses the TNSPs' proposal. The Commission relies heavily on the consultants findings when making its own assessment of the TNSPs' costs.

The second option is to continue with the Commission's current approach but to also adopt an efficiency carry-over mechanism. The efficiency carry-over mechanism rewards the TNSP with higher profits when the firm manages to lower its controllable costs.

The third option being considered is to make greater use of external benchmarks, for setting the price and revenue cap parameters. The Commission considers that this may result in more efficient practice, as benchmarking breaks the nexus with the firm's actual costs and revenues.

The Commission's preferred position

The Commission's preferred position is to rely more on benchmarking in the future when assessing the TNSP's opex costs.

Self Insurance and Pass-Through Events

The Commission considers expenditure on insurance by TNSPs to be a rational and prudent part of their risk management strategy and that all insurance options should be open to TNSPs, in appropriate circumstances, to ensure they acquire the most efficient insurance cover available. This is consistent with the Commission's incentive based form of regulation which seeks to recognise and include only efficiently incurred costs in the TNSPs' revenue requirement. Managers are provided with incentives to pursue ongoing efficiency gains through the control of expenditures.

However, some costs are essentially uncontrollable by nature and therefore cannot be subject to the same incentive measures. Consequently, as an alternative to receiving an allowance in their cash flows, arrangements may be put in place whereby TNSPs are able to pass-through the costs of certain designated events directly to the consumer.

As a general matter, TNSPs will endeavour to manage their risks by a number of means including:

- taking out insurance cover with external providers;
- self-insuring for certain other risks; or
- agreeing pass-through rules to pass the cost of designated events on to customers.

The Commission's preferred position

The Commission supports pass-through in limited circumstances. The Commission considers that it is important that the three approaches to cover risks including: taking out insurance with external providers; self-insuring for certain other risks; or agreeing pass-through rules to pass the cost of designated events on to customers are adequately scoped and defined to ensure there is no overlap between them. Guidelines for dealing with these matters have been included in the Commission's GasNet and SPI PowerNet revenue cap decisions issued in 2002.

Incentive Mechanism and Benefit Sharing

An important objective for any regulatory regime is ensuring that the regulatory regime yields continuous incentives for enhancing productive efficiency - that is, producing the required quality and quantity of output at least cost. The extent to which a given regulatory regime yields incentives for efficiency depends, in part, on how quickly and how fully any changes in cost observed by the regulator are reflected in the regulated prices. The common practice of using a five-year regulatory period enhances incentives for efficiency by introducing a lag between the time when the regulated firm exerts effort to lower its costs and the time when those lower costs are reflected in lower prices.

But the five-year regulatory period may also introduce other problems. Specifically, if the future regulated prices depend on the cost out-turn in just one year (the "test year") of the previous regulatory period, the regulated firm may have strong incentives to make cost reductions in some years and weak (or negative) incentives to make a cost saving in the test year. Some regulators have sought to address this issue through the use of a carryover of efficiency gains or losses from the previous regulatory period. However, whether or not such incentives are a problem depends on how future cost benchmarks depend on past costs.

This part of the discussion document invites comment on issues such as whether or not the Commission should adopt a mechanistic process for setting future prices on the basis of past costs? What objectives should the Commission seek in such a mechanism? What are the common characteristics of the class of mechanisms which yield constant incentives for cost efficiencies over time? Should the Commission be concerned about the ability to substitute capex for opex? Is there scope for the Commission to move to higher-powered incentives through greater reliance on external cost factors?

The Commission's preferred position

The Commission's preferred position is to adopt an incentive mechanism that creates constant incentives for efficiency over time.

Benchmarking

The Commission is currently exploring the use of benchmarking more when setting revenue and price caps. The Commission's initial view is that in order to increase the "power" of an incentive scheme greater weight should be placed on "exogenous" measures of cost. This is in contrast to a lower power incentive scheme as proposed by staff which is determined primarily by "endogenous measures of cost".

The discussion paper explores how those exogenous measures of cost are obtained, how they should be used, and how they have been used in practice in the regulation of electricity transmission and distribution companies. The salient points of the paper are: a) nearly all of the regulatory difficulty relating to the use of exogenous cost measures arises from the problem of distinguishing "legitimate" cost differences from differences due to controllable efficiency differences alone, b) establishing a data base of observable costs of a set of comparable firms, c) using this data to estimate a "cost model" which takes as an input different values of the cost-influencing factors and finally, d) obtaining information on the cost factors affecting the regulated firm and feeding them into the cost model to yield an exogenous estimate of the costs of the regulated firm.

The appropriateness of any cost model will, to a certain extent, depend on its ability to reduce or adequately account for "information rent", i.e. the excess return that is earnt by the TNSP as a consequence of its "true" cost falling below the regulated revenue. Exogenous cost measure are more sustainable the lower the information rent.

The Commission's preferred position The Commission's preferred position is to explore the scope for greater reliance on exogenous cost measures (often called "benchmarking") when setting the revenues of regulated TNSPs.

<u>*Weighted Average Cost of Capital*</u>

The TNSPs weighted average cost of capital (WACC) is one of the inputs in to the Commission's revenue cap determination. The WACC for a firm is the average of the costs of its equity, debt or other financing sources. The Code states that in determining a TNSPs revenue cap, the Commission must have regard to the service provider's fair and reasonable WACC.

This discussion paper considers various parameters within the WACC and CAPM framework. Amongst the more contentious parameters are the risk free rate and the equity beta.

The equity beta measures the systematic (non-diversifiable) risk of a particular stock relative to the market portfolio. To date the Commission's method of determining the equity beta has been a benchmarking approach with limited reference to actual market conditions.

The Commission has generally computed an equity beta of one for TNSPs. An equity beta of one implies that the firm has the same level of systematic risk as the market average. Intuitively an equity beta of less than one may be more appropriate for regulated TNSPs in Australia given the level of market risk which they face. These firms are regulated entities with a guaranteed revenue stream and a demand for their essential services that is inelastic.

In this regard the Commission considers that maintaining a benchmarked equity beta of one for TNSPs ignores current available market evidence that points to a lower equity beta for TNSPs. This would also be consistent with the Commission's approach in calculating forward looking estimates of other parameters based on latest market evidence. In order to minimise risk that the equity beta does adequately compensate the TNSPs the Commission propose to adopt the approach of incorporating an upper confidence interval to calculate a proxy for equity beta. This approach will also provide the TNSP with the potential for increased returns as the equity beta may be above one in certain circumstances, depending on the constructed confidence interval. These returns will however be linked to general market conditions.

Having said this, the Commission notes the concerns about the reliability and sample size of the current data. The availability of a limited data set may have implications for a rigorous estimation procedure which incorporate market based measures.

Accordingly the discussion paper welcomes comment from interested parties on the Commissions approach in deriving equity beta from market data. Also given the limited availability of market data, comment is invited on the estimation of the equity beta in the future and in the interim.

Regarding the risk free rate, the Commission prefers the use of a government bond rate, matching the length of the regulatory period, as a proxy for the risk free rate. Conversely TNSPs argue for a 10 year rate as the longer term better reflect its investment horizon and asset lives. The Commission has maintained in the past that the 5 year rate matches the regulatory period and does not reward additional interest rate risk which is not being borne.

The Commission's preferred position

The Commission's initial view is to move towards benchmarking an equity beta from current market evidence and incorporating an upper confidence interval.

In addition, the Commission's preferred position is to adopt a government bond rate that matches the regulatory period as a proxy for the risk free rate.

Other issues relevant to the DRP but not covered by the discussion paper

A number of other issues will be incorporated into the Regulatory Principles 2004 document. These issues have all followed a separate process for review and are in various stages of completion. The issues below have all been subject to a public consultation process.

Ring-Fencing Guidelines

Part G of Chapter 6 of the Code requires the Commission to develop Transmission Ring-Fencing Guidelines. The Commission published its Transmission Ring-Fencing Guidelines on 15 August 2002.

The Transmission Ring-Fencing Guidelines require TNSPs to provide specific financial statements and compliance reports at intervals determined by the Commission and in accordance with any guidelines issued by the Commission.

In addition to the Transmission Ring-Fencing Guidelines, TNSPs are required under clause 6.2.5 of the Code to provide specific financial accounts to the Commission in a form and at intervals determined by the Commission. In June 2002, the Commission released its Information Requirements Guidelines under clause 6.2.5. These Guidelines require the separation of information between the TNSP's regulated and unregulated activities.

The Commission has previously stated in the Transmission Ring-Fencing Guidelines that the Commission does not, at this stage, intend to impose obligations in addition to those already imposed under the Information Requirements Guidelines. Accordingly, the

Commission issued for comment (Draft) Reporting Guidelines under the Transmission Ring-Fencing Guidelines on 15 August 2002. No submissions were received in response to the Draft. As a result the Commission released the (Final) Reporting Guidelines on 23 October 2002.

Information Requirements Guidelines

The (Final) Reporting Guidelines are intended to ensure that a TNSP's obligations under the Transmission Ring-Fencing Guidelines are consistent with its obligations under the Information Requirements Guidelines.

The Commission issued its Information Requirements Guidelines on 5 June 2002. The Commission's objective in issuing these guidelines is to transparency about performance of the TNSPs including costs; profits; investment and allocation of costs between the regulated network business and contestable parts of the business. In particular, the Commission is seeking to ensure that regulated activities do not cross-subsidise contestable activities.

The accounting separation requirements are reflected in the Guidelines which are to be read in conjunction with the Transmission Ring Fencing Guidelines and the Service Standards Guidelines which have recently been released as a draft decision.

Under Part G, Chapter 6 of the Code, TNSPs must maintain a separate set of accounts in respect of ring fenced services which are defined to mean prescribed services (non-contestable services). Consequently, TNSPs must separate out prescribed and non-prescribed services when performing their regulatory accounting. TNSPs are also required to reasonably allocate costs that are shared between prescribed services and any other activities. Clauses 6.2.5(a) and (c) of the Code requires TNSPs to submit to the Commission certified annual financial statements and the information provided by the regulated TNSP will form the basis of the Commission's revenue cap decisions. The Commission will also use the information to annually monitor the TNSP's compliance with its revenue cap.

Service Standard Guidelines

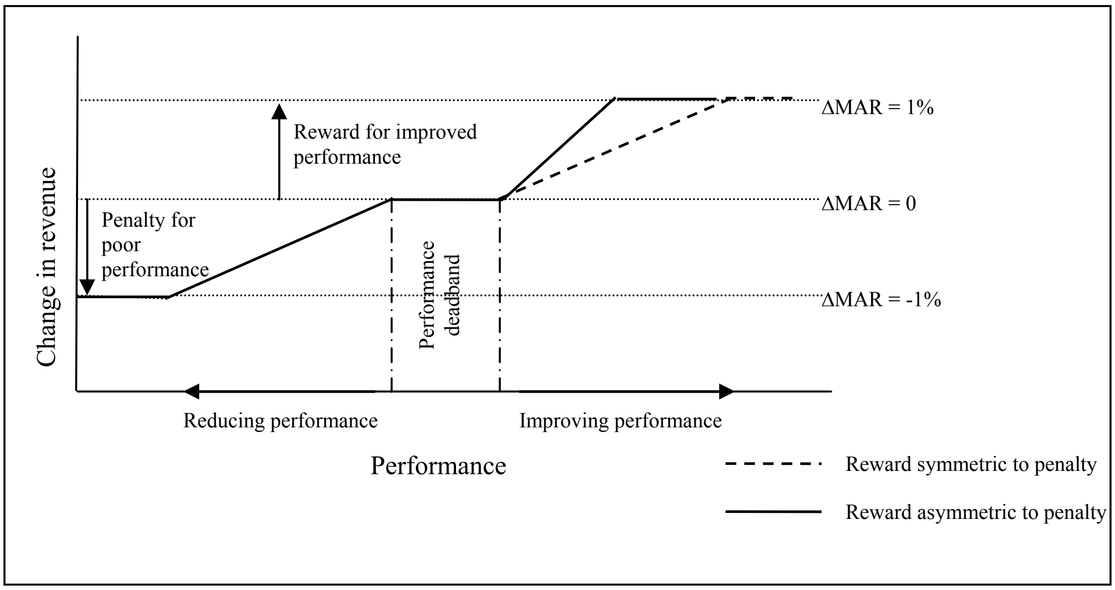
Part B of Chapter 6 of the Code requires the Commission to set revenue caps for TNSPs. As part of each decision the Commission must be satisfied with the level of service that TNSPs will provide in return for its maximum allowed revenue. Therefore it is developing service standards guidelines to outline how service levels will be considered in revenue cap decisions.

The Commission published its draft service standards guidelines on 28 May 2003. These guidelines, when finalised, will inform TNSPs what service standards information to provide to the Commission in their revenue cap applications and in their annual revenue cap compliance statements.

The draft guidelines propose to use a TNSPs own historical performance to set a performance benchmark. Then any improvements or reductions in performance will result in an increase or decrease in the regulated revenue allowed. These increases and decreases in the regulated revenue will be initially capped at 1% of the TNSP's annual regulated revenue. The Commission will explore raising this cap when it is satisfied with the incentives the scheme provides. The building block formula that accounts for service standards is outlined above.

The performance-incentive scheme recommended by SKM has various controls to allow the Commission to ensure appropriate incentives are set. In Figure 1 below it can be seen how the use of asymmetric rewards and penalties can be used to account for poor, or high, quality existing performance levels. Also the performance dead band may be adjusted to ensure minor variations around the historical levels to not result in a reward or penalty.

Figure 1 – Performance Incentives



The measures of performance that the Commission adopted in its draft guidelines are:

- Circuit availability, which is a measure of the percentage availability for service of a given set of assets. For example, transformers may be out of service 1 per cent of time due to outages, hence they are 99 per cent available.
- Outage duration, which is the average time of outages over the year.
- Frequency of loss of supply events, which is the number of outages that occur over the year. These outages may be grouped into outages that last more than 0.1 minutes, 0.2 minute, 1 minute, etc.

- Hours of inter-regional constraints, this is the total time of constraints that limit power flows between regions.

- Hours of intra-regional constraints, this is the total time of constraints that limit power flows within a region.

The Commission held a public forum on 15 July 2003 on its draft service standards guidelines, where various interested parties presented their views on the draft guidelines. The final guidelines are expected to be released in October 2003.

Review of the regulatory test

On 15 December 1999 the Commission, in accordance with Chapter 5 of the Code released its regulatory test. The regulatory test is a cost-benefit analysis test that augmentations to a transmission network must pass in order to gain regulated status.

On 10 May 2002 the Commission released an Issues Paper as part of a commitment to review the regulatory test. The Issues paper highlighted a number of concerns raised by interested parties with the operation of the current regulatory test.

From the submissions to the Issues Paper, the Commission identified three options for the development of the regulatory test. The three options are outlined in the Discussion Paper which was released on 5 February 2003.

- Option one aims to ensure consistency between the regulatory test and the Code.

- Option two addresses concerns that the application of the regulatory test is open to considerable discretion and puts forward a number of definitions to be used by transmission and distribution businesses when applying the regulatory test.

- Option three looks at ways of broadening the scope of the regulatory test to include the benefits of increased competition that can result from improved interstate transmission links.

A Market Review Forum held in July 2003 allowed for discussion of these issues. The Commission is expected to publish a draft determination in 2003.

The Discussion Paper on the review of the DRP does make reference to the Regulatory Test in section 3; however, the discussion focuses more on the Commission's objective to ensure efficient investment rather then the mechanics of the Regulatory Test itself.

Process for the Review

This Discussion Paper should be read in conjunction with the existing DRP.

Interested parties are invited to make written submissions to the Commission on the issues raised in this Discussion Paper. The closing date for submissions is ***28 November 2003.***

This paper does not address, nor seek comment on any issues outside of the requirements identified in chapter 6, Part B of the Code, nor does it provide an exhaustive list of all the matters the Commission will address in its Draft Regulatory Principles 2004.

The Draft Regulatory Principles 2004 will be developed taking into account submissions, expert advice and the Commission's own work in other areas, such as gas and telecommunications and transport. The Draft Regulatory Principles 2004 will be released in the first quarter next year. The Regulatory Principles 2004 is intended to be released later on in the year.

Submissions

Submissions can be sent electronically to: electricity.group@accc.gov.au
Alternatively, written submissions or submissions on disk, in either Word 7.0 or PDF format, can be sent to:

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The Commission particularly asks that those making submissions explain how their preferred approaches for addressing the issues meet the principles and objectives set out in sections 6.2.2 and 6.2.3 of the Code and other relevant parts of the Code. The principles and objectives are summarised in Box 1 above.

1 Introduction

Background

In 1990, as part of the Commonwealth Government's commitment to micro-economic reform, the Industry Commission (IC) was requested by that Government to undertake an inquiry into the efficiency of the generation, transmission and distribution of electricity and the transmission and distribution of gas.

In 1991 the IC produced their Report entitled *Energy Generation and Distribution*. The Report recommended a major restructuring of the Australian electricity and natural gas supply industries to increase competition and thus efficiency.

As an extension of the micro-economic reform agenda, in 1991 the Council of Australian Governments[1] (COAG)[2] agreed to examine a national approach to competition policy. The first step in this process was the establishment in the following year of the National Competition Policy Review by a committee chaired by Professor Fred Hilmer.

On completion of the Hilmer Committee's Report in August 1993, the Commonwealth, State and Territory Governments began extensive negotiations on implementation of its recommendations. The recommendations made by the Hilmer committee were generally accepted by COAG in April 1995 and the processes culminated in the Competition Policy Reform Act 1995.

The Competition Policy Reform Act 1995 when coupled with three inter-governmental agreements (the Competition Principles Agreement, the Agreement to Implement the National Competition Policy and Related Reforms and the Competition Code Agreement), resulted in a number of wide ranging reforms that included the agreement that all State and Territory governments and the Commonwealth would review and, where appropriate, reform legislative restrictions on competition.

The broader competition policy reforms embodied in the three inter-governmental agreements operated in tandem with the COAG reforms to the electricity market. The COAG reforms brought vertical separation of contestable from non-contestable services to the market, introduced competition to generation and retail sectors and brought non-contestable transmission and distribution networks under access and price regulation. The COAG agreements also provided for creation of the NEM and the National Electricity Code (Code).

The NEM is a wholesale market for the supply and purchase of electricity and it commenced operation in December 1998 in southern and eastern Australia.

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1 The role of COAG is to initiate, develop and monitor the implementation of policy reforms which are of national significance and which require cooperative action by Australian governments.

2 Being the Prime Minister, Premiers and Chief Ministers of the Commonwealth, State and Territory Governments

The Code was established under the National Electricity Law enacted in each participating jurisdiction. The Code sets out the NEM rules for participating in the wholesale electricity market and forms the basis of an industry access code for transmission and distribution businesses participating in the NEM.

The Code is administered by the National Electricity Code Administrator Ltd (NECA), and the NEM itself is operated by the National Electricity Market Management Company (NEMMCO).

The Commission's Role as Regulator of Transmission Revenues

The Commission has assumed responsibility for the regulation of transmission revenue in the NEM, on a progressive basis, since 1 July 1999. The Commission's power to perform this regulatory role stems from Part IIIA of the Trade Practices Act 1974 (TPA).

The arrangement for the operation of the NEM is set out in the Code. The Code outlines the general principles and objectives for the transmission revenue regulatory regime to be applied by the Commission. (see Box 1 for more detail).

Box 1: Objectives and principles of the transmission revenue regulatory regime

The Code establishes that:

1. the transmission revenue regulatory regime must achieve outcomes which:
   (a) are efficient and cost effective;
   (b) are incentive based that share efficiency gains between network users and owners and provide a reasonable rate of return to network owners;
   (c) foster efficient investment, operation, maintenance and use of network assets;
   (d) recognise pre-existing government policies on asset values, revenue paths and prices;
   (e) promote competition; and
   (f) are reasonably accountable, transparent and consistent over time;
2. the regulation of aggregate revenue of transmission networks must:
   (a) be consistent with the regulatory objectives (see 1 above);
   (b) address monopoly pricing concerns, wherever possible, through the competitive supply of network services but otherwise through a revenue cap;
   (c) promote efficiency gains and balance supply and demand side options;
   (d) promote a reasonable rate of return to network owners on an efficient asset base where:
      (i) the value of new assets is consistent with take-or-pay contracts or NEMMCO augmentation determinations;
      (ii) the value of existing assets are determined by jurisdictional regulators and must not exceed their deprival value; and
      (iii) any asset revaluations undertaken by the Commission are consistent with COAG decisions;
3. the form of the economic regulation shall:
   (a) be a revenue cap with a CPI-X incentive mechanism;

(b) take into account expected demand growth, service standards, weighted average cost of capital, potential efficiency gains, a fair and reasonable risk adjusted return on efficient investment and ongoing commercial viability of the transmission industry;

(c) have a regulatory control period of not less than five years; and

(d) only apply to those assets not expected to be offered on a contestable basis.

Source: National Electricity Code, clauses 6.2.2 – 6.2.5.

The Code prescribes the broad form of regulation to be applied to each Transmission Network Service Providers (TNSPs) revenues. It also grants the Commission the flexibility to use alternative methodologies providing they are consistent with the Code's objectives and principles. For example the Code requires the Commission to set a revenue cap for TNSPs. However, if the Commission considers there is sufficient competition to warrant a more light handed regulatory approach it may determine and apply such an approach.

The Draft Regulatory Principles (DRP)

The Code requires the Commission to publish a *Statement of Regulatory Intent* which establishes guidelines as to how it will exercise its regulatory powers. The Commission released its Draft Regulatory Principles (DRP) for the regulation of transmission revenues in May 1999. In developing the DRP the Commission drew heavily on Chapter 6 of the Code, in particular the principles and objectives espoused in section 6.2 and as outlined in Box 1 above.

The Commission has adopted the DRP as a guide in setting TNSP revenues. In delivering regulatory outcomes the Commission is conscious of the need to strike a balance between the interests of customers and investors, between service standards and price, and need to provide appropriate incentives for long term efficient investment.

The DRP sets out the Commission's intended approach to setting CPI-X revenue caps for regulated electricity TNSPs in the NEM. In determining a revenue cap the DRP adopts a cost building block approach based on the following expected efficient costs:

- operating and maintenance expenditure;
- capital expenditure;
- a rate of return on the TNSP's regulatory asset base (RAB), including an adjustment for tax liability; and
- depreciation of the RAB.

The building block approach calculates the Allowed Revenue (AR) as the sum of the return on capital, the return of capital, operating and maintenance expenditure and taxes. The building block formula is:

	AR	=	return on capital + return of capital + opex + tax
		=	(WACC * WDV) + D + opex + tax
where:	AR	=	allowed revenue
	WACC	=	post-tax nominal weighted average cost of capital
	WDV	=	written down (depreciated) value of the asset base
	D	=	depreciation
	opex	=	operating and maintenance expenditure
	tax	=	expected business income tax payable

However, in determining the MAR, the Code requires the Commission to take into account the service standards that TNSPs are expected to maintain. Therefore, the Commission will adopt an annual service standard adjustment in the calculation of MAR, that is:

$$\mathrm{MAR}_t = \text{(allowed revenue)} + \text{(financial incentive)}$$

$$= \left(\mathrm{AR}_t\right) + \left(\frac{(\mathrm{AR}_{t-1} + \mathrm{A}R_{t\text{-}2}\ )}{2} \times S_{ct}\right)$$

Where:

MAR	=	maximum allowed revenue
AR	=	allowed revenue
S	=	service standards factor
t	=	regulatory period
ct	=	calendar year

The Review of the Draft Regulatory Principles (DRP)

The review of the DRP is being conducted now as the Commission has had four years of experience in regulating TNSPs' revenues. This review aims to assess the operation of the DRP and provide all interested parties with an opportunity to influence the future development of the Commission's *Statement of Regulatory Principles*.

The *Statement of Regulatory Principles* is not legally binding and it must be accepted that, in line with achieving best practice regulation, the Commission's position on some issues may change. The Commission expects that the *Statement of Regulatory Principles* will evolve in response to improvements in regulatory models and best practice regulation worldwide.

In addition the Commission notes that its preferred position in regard to a number of the Weighted Average Cost of Capital (WACC) parameters may be subject to the Australian Competition Tribunal (Tribunal) findings in relation to GasNet's appeal against the Commission's 2002 access arrangement.

In developing the principles the Commission has used of the following consultants: Kevin Davis in respect to the WACC parameters, Jeff Blachin in respect to the question of revaluation of the asset base and Darryl Biggar in respect to incentive mechanisms and benchmarking.

Process for the Review

This Discussion Paper should be read in conjunction with the existing DRP.

Interested parties are invited to make written submissions to the Commission on the issues raised in this Discussion Paper. The closing date for submissions is ***28 November 2003.***

This paper does not address, nor seek comment on any issues outside of the requirements identified in chapter 6, Part B of the Code, nor does it provide an exhaustive list of all the matters the Commission will address in its Draft Regulatory Principles 2004.

The Draft Regulatory Principles 2004 will be developed taking into account submissions, expert advice and the Commission's own work in other areas, such as gas and telecommunications and transport. The Draft Regulatory Principles 2004 will be released in the first quarter next year. The Regulatory Principles 2004 is intended to be released later on in the year.

Submissions

Submissions can be sent electronically to: electricity.group@accc.gov.au
Alternatively, written submissions or submissions on disk, in either Word 7.0 or PDF format, can be sent to:

Mr Sebastian Roberts
General Manager
Regulatory Affairs – Electricity
Australian Competition and Consumer Commission
GPO Box 520J
Melbourne VIC 3001

The Commission particularly asks that those making submissions explain how their preferred approaches for addressing the issues meet the principles and objectives set out in sections 6.2.2 and 6.2.3 of the Code and other relevant parts of the Code. The principles and objectives are summarised in Box 1 above.

2 Revenue Cap Decision Making Process

2.1 What is the issue?

Clause 6.2.4(b) of the Code requires the Commission to provide a description of the process and timetable for resetting the revenue cap of regulated TNSPs. Subsequently, chapter 2 of the DRP outlined the proposed decision making process. The Commission is now considering possible amendment to this process in order to increase accountability, transparency and achieve best practice regulation.

2.2 How has the revenue process been dealt with to date?

2.2.1 The regulatory review procedure

Chapter 2 of the DRP sets out a six month regulatory review process which is outlined in figure 1.

The regulated TNSP is required to submit an application to the Commission, setting out their required MAR. The application must comply with the Commission's *information requirements guidelines*[3] and must be accompanied with sufficient information to support the MAR which is to apply over the forthcoming regulatory period. The Commission may review the application to ensure that it complies with the *information requirements guidelines.* If the Commission is not satisfied it may provide written notice to the TNSP that the application is unsatisfactory and has not been accepted as an application. The TNSP must then resubmit the application addressing the issues outlined in the notice.

Once an application has been accepted, the Commission will call for submissions commenting on the application, usually allowing four weeks from the publication of the notice for the submissions to be lodged.

Absent any claim of confidentiality, all submissions and relevant documents are placed on a public register.

The Commission assesses the application against the objectives pursuant to clause 6.2.2 of the Code and the principles of best practice regulation, which:

- recognises pre-existing government policies on asset values, revenue paths and prices
- eliminates monopoly pricing
- fosters efficient investment
- provides a fair return to network owners

3 ACCC, *Statement of Principles for the Regulation of Transmission Rev*enues – Information Requirements Guidelines, June 2002.

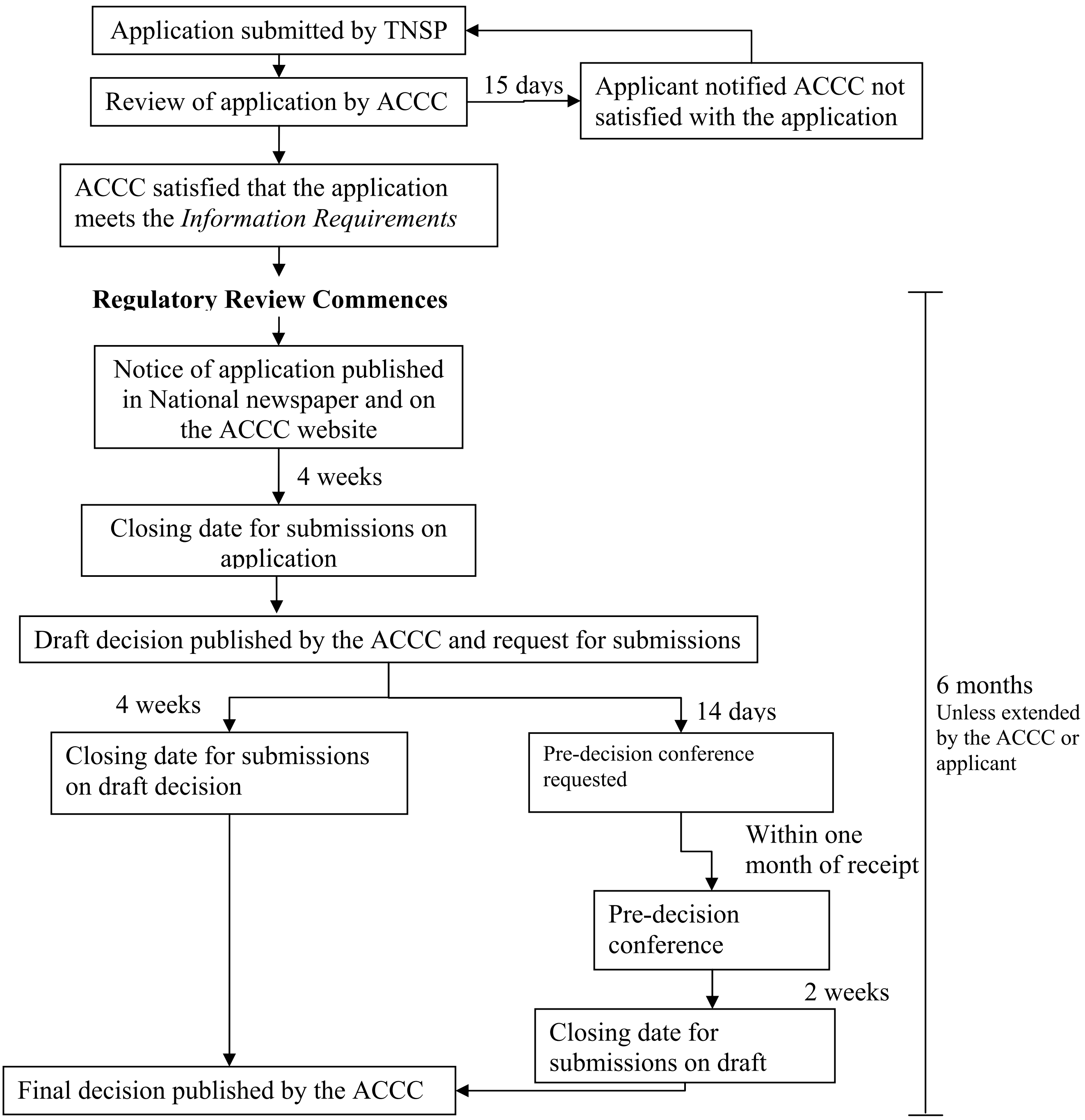
- creates incentives for managers to pursue ongoing efficiencies through cost reductions
- promotes economic efficiency
- provides for a transparent regulatory process which is consistent over time
- minimise compliance costs.

As required by clause 6.2.6 of the Code (outlined below), the Commission publishes full and reasonable details of the basis and rationale for the draft decision, including but not limited to:

- reasonable details of qualitative and quantitative methodologies applied, including any calculations and formulae
- the values adopted for each of the input variables in any calculations and formulae, including a full description of the rationale for adoption of those values
- reasonable details of other assumptions made in any material analysis undertaken in relation to the setting of a revenue cap or related matter
- full reasons for all material judgements and qualitative decisions made and options considered, and all discretions exercised which have a material bearing on the outcome of the Commission's overall decisions.

If no pre-decision conference is called then the Commission will then publish a final decision on the application taking into consideration the additional information presented in any submissions made following the release of the draft decision.

Figure 1: Current ACCC Regulatory Review Procedure



2.2.2 Treatment of late submissions

If a submission cannot be finalised before the closing date, then the interested party must request the Commission grant an extension. In granting an extension the Commission will request a draft submission be lodged by the original closing date, outlining all the key arguments to be presented in the final submission.

2.2.3 Pre-decision conference

After the Commission has published the draft decision, any interested party who wishes to comment on the draft decision may request a pre-decision conference within two weeks of the release of the draft decision. If a pre-decision conference is requested, it will be held within one month of the request date.

Interested parties may make submissions following the release of the draft decision and the pre-decision conference. Submissions must be provided within four weeks of the release of the draft decision or if a pre-decision conference is held, two weeks after the conference.

2.2.4 Confidentiality

Upon receiving an application, the Commission reviews any accompanying requests that all or part of the application remain confidential. Upon review of this request the Commission will place all information and submissions upon a public register, except for that information that the Commission considers to be confidential.

2.3 Should the Commission change the revenue review process?

2.3.1 The regulatory review procedure

Since the release of the DRP the Commission has gained considerable experience through the determination of five revenue cap decisions.[4] The timeline of six months as outlined in the DRP has been inadequate for all five decisions. Previous revenue cap decisions have been completed in an 8-12 month timeframe.

2.3.2 Treatment of late submissions

There is continued criticism from interested parties that the Commission does not allow sufficient time for an adequate response to be made. As a result the Commission has consistently needed to grant extensions to the closing date for submissions.

2.3.3 Pre-decision conference

The operation of the pre-decision conference which is outlined in the DRP requires clarification. Foremost, the pre-decision conference is not convened under section 90A of the TPA, therefore, the Commission has greater flexibility in the manner in which it conducts the conference.

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[4] ACCC, decision-*NSW and ACT Transmission Network Revenue Caps 1999/00-2003/04*, January 2000.
ACCC, decision-*Snowy Mountains Hydro-Electric Authority Transmission Network Revenue Cap 1999/00-2003/04*, February 2001.
ACCC, decision-*Queensland Transmission Network Revenue Cap 2002-2006/07*, November 2001.
ACCC, decision-*South Australian Transmission Network Revenue Cap 2003-2007/08*, December 2002.
ACCC, decision-*Victorian Transmission Network Revenue Caps 2003-2008*, December 2001.

2.3.4 Confidentiality

Confidentiality requests fetter the Commission's ability to provide a clear and transparent process, and to seek input from experts in the industry and industry participants. Therefore the Commission seeks to limit the amount of confidential information that is used in the regulatory review process.

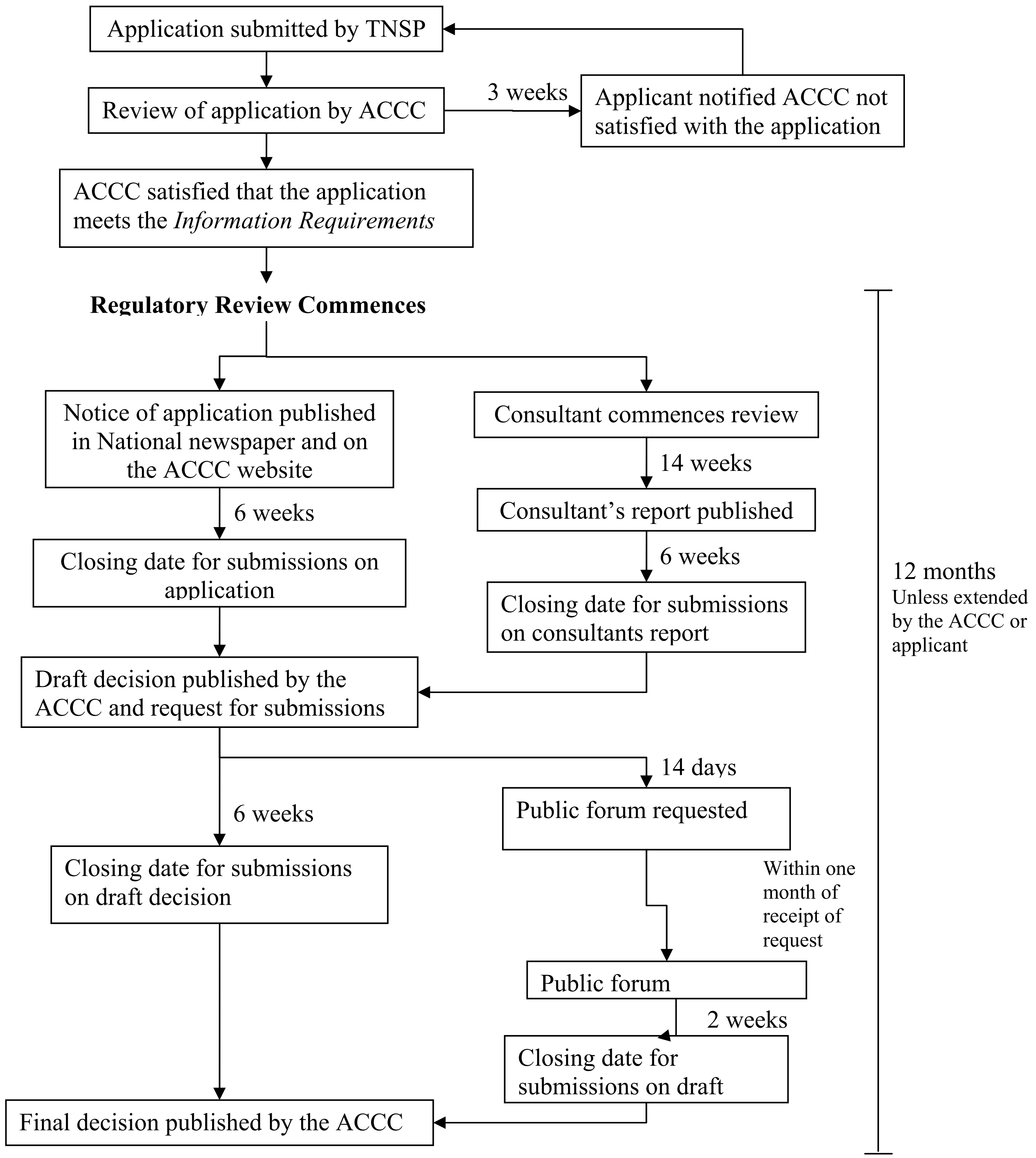
2.4 What is the change?

2.4.1 Regulatory review procedure

The Commission proposes to extend the regulatory review procedure to a twelve month process. This additional time will facilitate consultation by interested parties at all stages of the review process.

The Commission's proposed timetable is set out in figure 2.

Figure 2: Proposed ACCC Regulatory Review Procedure



2.4.3 Treatment of late submissions

By extending the period of time for submissions from four weeks to six weeks, the Commission believes this should provide interested parties adequate time to prepare their submissions.

However, if a submission is received after the closing date then the Commission will adopt a similar process as that adopted by NEMMCO.

Late submissions will only be considered by the Commission at its discretion. Notification must be provided to the Commission before the close of submissions and must include the following for consideration:

- the reason for the lateness
- the detriment to the interested party if the Commission fails to consider the submission.

2.4.4 Public forum

Any pre-decision conference required for the purposes of a revenue cap decision will be termed a public forum.

Public forums will not be convened under s 90A of the TPA; however, the Commission will generally seek to conduct the forum in accordance with those procedures.

The exception is where the Commission receives requests from persons who would not usually be entitled to participate in a pre-decision conference in accordance with s 90A of the TPA. Usually only parties that have a real and substantial interest in the decision may participate. This is designed to ensure that the pre-decision conference remains focussed on the views of parties directly affected by the Commission's decision.

However, given that a public forum is not convened under s 90A of the TPA, the Commission does have the flexibility to allow wider participation by suitably qualified persons who may wish to present their views on the merits of the Commission's draft decision or to speak on behalf of interested parties. The Commission will consider such requests to participate on a case by case basis.

2.4.5 Confidentiality

The Commission seeks to maintain a clear and transparent review procedure. The Commission notes that confidentiality requests by the applicant will impede consultation and industry participation in the revenue cap review. Thus, such requests will be assessed when reviewing the application and only granted where justified by the applicant. Where a request for confidentiality is declined the applicant may withdraw the relevant material from the application.

The Commission will continue with its intention to publicly release information in accordance with clauses 6.2.6(b)-(e), subject to any appeals process initiated by the applicant.

2.5 What will be the effect of the change?

The proposed changes put forward in this paper aim to establish a regulatory review procedure that will facilitate greater consultation, fairness and help achieve a transparent and predictable regulatory regime.

2.6 The Commission's preferred position

The Commission proposes to extend the regulatory review period to twelve months.

Proposed changes to the revenue review process for consideration

Comments are invited on the proposed changes to the:

- regulatory review procedure
- the operations and procedures of a public forum
- treatment of late submissions and
- confidentiality requirements.

3 Asset valuation – review of periodic revaluation versus the merits of lock-in

3.1 What is the issue?

In finalising the *Statement of Regulatory Principles* the Commission will need to consider its approach to treating assets at the next revenue re-sets. It should be noted that this paper defines assets as fixed assets and easements.

A fixed asset is simply an asset that is part of the transmission network system. All of the assets in the asset base are defined as fixed assets except for easements.

An easement is a right to use a portion of land owned by another party. An easement does not necessarily give the holder an exclusive right to the land. The owner of the property over which the easement is held is, however, usually prohibited from using the land in a manner which restricts the use of the easement or creates safety risks. In the case of TNSPs, an easement usually gives the holder of the easement the right to erect transmission lines on an area of land usually defined in terms of size by the land occupied by the transmission tower, and by safety considerations (i.e. certain distance from power lines).

The Commission believes that there are three main options for considering future reviews of the asset base. The first is to revalue assets on a periodic basis (for example each five-year regulatory period) using the Depreciated Optimised Replacement Cost (DORC) methodology. The second option is to set the asset base by adopting the initial jurisdictional valuation and adding in new investment at cost. This approach is based on the gas code. The third option being considered is to conduct a one off revaluation of the jurisdictional asset base using DORC, and roll in new investment at cost in subsequent regulatory periods.

If the Commission decided to lock-in the jurisdictional asset base it would lock-in both the fixed assets and easements. If the Commission decided to revalue the jurisdictional asset base it would revalue the fixed assets using the DORC methodology. However, it might revalue easements using a DORC or historic cost methodology.

Refer to Attachment A – consultancy report by Jeff Balchin for a more detailed discussion in regard to the methodology for updating the regulatory value of electricity transmission assets.

3.2 How has the Commission determined the asset base to date?

Code and institutional requirements

The DRP states that the Commission will adopt a DORC approach when valuing the asset base.

The Code requires the Commission for the first regulatory review to value sunk assets at the value determined by the Jurisdictional Regulator or consistent with the regulatory asset base established in the jurisdiction, provided that this value does not exceed deprival value. The Jurisdictional Regulators determined the value of the TNSPs' sunk assets by using DORC, with the exception of easements in some cases where historic cost was used.

The DRP has adopted a DORC approach when determining asset valuation. This has mainly come about through the code requirements. The Code's provisions regarding calculation of asset values are generally very broad. While there is a wide range of asset valuation methodologies, the Code also requires the Commission to give consideration to the Optimised Deprival Value (ODV). An ODV is the minimum loss that would result if the business were deprived of the asset. For example, where the asset can and should be replaced, the deprival value is the Replacement Cost (RC). If the asset would not be replaced, then the deprival value is the greater of the Net Present Value (NPV) of expected cash flows from continued use of the asset or the net realisable value of disposing the asset.

The Code requires the Commission for the first regulatory review to value sunk assets at the value determined by the Jurisdictional Regulator consistent with the regulatory asset base established in the jurisdiction, provided that this value of the TNSPs' sunk assets by using DORC, with the exception of easements in some cases where it used historic cost.[5]

The Code does provide that for the second regulatory review, existing and new assets can be revalued, on a basis determined by the Commission. Nevertheless, the Commission does not have unlimited discretion in determining an asset valuation methodology, as the Code requires the Commission to satisfy a number of principles and objectives. These include the need to provide a fair and reasonable rate of return as well as the need to have regard to the COAG's preference for deprival value.

The Commission can state its intentions in determining the valuation for future asset bases; however, it cannot simply refuse to give consideration to a particular request. For example, if a TNSP were to request an alternate approach to that settled by the Commission, the Commission may refuse that request, but it must be satisfied that its preferred approach best satisfies the objectives of the Code.

3.2.1 Draft Regulatory Principles

Where valuation is divorced from the competitive market, there is no necessarily correct procedure for valuing assets. Numerous methods of asset valuation are available, and are widely used in differing circumstances by both the private and public sectors for different reasons. However, for determining the value of the underlying regulatory asset base, these methods can be characterised under two main approaches, cost based and value base.

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Cost based approaches such as DORC relate the value of an asset to the cost of purchasing the asset or the service potential embodied in the asset, either at the original cost or the original cost adjusted to reflect its current cost.

Value based approaches such as ODV determine the value of an asset largely from its cash generating capacity. This can be measured by the net present value of future cash flows or the cash generated by selling the asset – the economic value.

The Code requires the Commission to take into consideration the ODV methodology when setting revenues. The main economic principle for assessing the economic value of any asset is that its value to investors is equal to the net present value of the expected future cash flows generated by those assets. However, there is a practical difficulty in making this assessment for regulated monopoly businesses as the future revenue derived from those assets is itself determined by the regulator.

Fixed Assets

The Commission decided to adopt the DORC approach in regard to fixed assets to avoid the problem of circularity that arises when trying to value a regulated asset on the basis of associated regulated revenue. The fundamental intention behind DORC is to divorce the asset valuation from revenue streams. DORC is a *cost based* valuation precisely because there is a degree of arbitrariness about the assumed future level and profile of revenues that an asset may be able to generate.

The DRP states that the underlying economic concept for DORC is that the DORC-based tariffs mimic the discipline of an *efficient* market. More specifically, DORC is held out as the upper limit of the regulated asset base (RAB), above which a new entrant would be attracted, and is therefore the asset base on which a profit maximising asset owner would fix tariffs in a contestable market.

The determination of a valuation for a TNSPs asset base on the basis of DORC involves three stages. The standard approach has been for these steps to compromise:

- Optimisation – determine the optimal configuration and sizing of transmission assets;
- Replacement cost (RC) – a modern engineering equivalent (MEE) is established for each assets in the optimised assets and a replacement cost established; and
- Depreciate those MEE assets (traditionally using straight-line depreciation) using the standard economic life of each existing asset together with an estimate of the remaining life of each existing asset. For example, if the standard economic life of an existing asset is 40 years and its remaining life is 10 years, the asset would be depreciated to 25 per cent of the replacement cost of the MEE.[6]

[6] ACCC, (May 1999), Draft Regulatory Principles (DRP).

Easements

In regard to easements, the DRP states that the normal DORC methodology would assign values to such assets reflective of their market value. Given the strong link with real estate values there is a likelihood that the value of easements will escalate continuously over time, at times in excess of the rate of increase in CPI. The question is how to introduce such assets into the regulatory framework in a consistent way.

The DRP states that one consistent would require:

- The contribution to the RAB is based on the actual cost to the TNSP of obtaining the easement rights updated periodically in line with what would be the DORC based valuation of easements. On the basis of legislated mechanisms for purchase of easements both of these valuations would normally be in line with what was considered the loss of amenity to the previous owner of conceding the easement right (that is its social costs).

- To the extent that easement valuations are judged to vary over time, the variations in value should be reflected in depreciation allowances linked with the assets in precisely the same way as other assets. If the easement appreciates in value over time then the allocated depreciation would be negative in nominal terms and serve to offset the higher capital returns associated with an appreciating asset value.

- If the easement right is resold, the RAB value should be close to the sale price given the basis for valuation updates. Hence, the issue of return associated with possible capital gain, and its effect on overall regulatory return, disappears. Should there be a residual capital gain or loss it will be hopefully small enough in magnitude to be accommodated by depreciation adjustments to the regulatory asset base at the start of the next review period in a way similar to that used to account for errors in depreciation associated with forecast capital expenditure that does not take place as planned.[7]

Re-valuations of the asset base

The DRP discusses the issue of revaluation. It notes that revaluations of DORC are made up of two components:

- the replacement of the asset with an asset providing a similar service to the asset in question (technological change i.e. RC); and

- the removal from the RAB of assets that no longer contribute to the delivery of services (redundant assets i.e. optimisation).

As discussed, revaluing the asset base based on DORC has a number of benefits, in particular, it would ensure that the regulated tariffs are never set at a level that is consistent with an asset value above DORC – this ties in with the definition of DORC i.e. that it represents the maximum value that would be reflected in prices in a competitive market. At the same time optimisation removes from the asset base assets that are no longer in service.

[7] *Ibid*.

> Changes in either of the two components i.e. changes in the replacement costs or an increasing redundancy of assets, may trigger a revaluation of the asset base.[8]

The DRP further states that the Commission's reasons for revaluing the asset base include:

- a major advance in technology such as the development of new materials;
- mergers or change of ownership of transmission assets;
- major expansions or contractions of the network such as may arise due to the development of a by-pass option;
- evidence that the TNSP is unable or unwilling to recover the full cost of service calculated for some sub-system; and
- a request by the TNSP facing a by-pass for a significant economic write-down of part of its asset base.[9]

Treatment of revaluations of the asset base

There are two main methods in treating revaluations. The Commission could choose to revalue the asset base and any rise or fall in the value of the asset base could be accounted for by positive or negative depreciation. The Commission considers that if the regulator revalued the asset base and provided compensation it would neutralise the affect of the revaluation.

In contrast the Commission could choose to revalue the asset base and any rise and fall of the asset base would not be accounted for by depreciation. The Commission considers that this is a more appropriate treatment of revaluations.

The regulator could do this for example if it judged that an original asset valuation and the revenue stream derived from it were inaccurate in some way and the Commission did not have the necessary information to correct the inaccuracy. For example a TNSP's asset base might include an easement valuation that did not reflect the TNSP's expenditure on that easement or there was an optimisation process carried out and now the assets are back in service.

3.3 Should the Commission change its approach to valuing assets?

As noted there are a number of options the Commission will need to consider in treating assets in the next revenue re-set. The Commission believes that there are three main options for considering future reviews.

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8 *Ibid*.
9 *Ibid*.

3.3.1 Option 1 – Revaluation of assets on a periodic basis

Reasons to revalue the asset base on a periodic basis

There are a number of reasons as to why the Commission might wish to re-value the asset base:

- unsure of the rigour and correctness of the valuation it has adopted from the jurisdiction;
- periodic revaluation could provide superior allocative economic efficiency outcomes; and
- periodic revaluations address concerns in regard to possible over investment i.e. gold plating and Averch/Johnson affect.

Unsure of the rigour and correctness of the valuation

In the first regulatory period the Commission was constrained by the Code and had to adopt the jurisdictional valuation. For the second revenue reset the Code provides the Commission the power to revalue and correct for mistakes at the initial regulatory reset. All of this arises from the Code's aim to transfer responsibility from the Jurisdictional Regulator to the National Regulator.

The Commission has never commissioned a *full valuation* of any of the TNSPs' assets. However, to simply assume that the jurisdictional valuations are appropriate (to the extent that they generate an efficient rate of return) would be to neglect one of the Commission's main responsibilities under the Code. If the Commission is not confident that the jurisdictional asset values generate efficient returns it could re-value at the initial re-set to ensure that errors in the asset base are not perpetuated into the future.

Allocative efficiency

Allocative efficiency occurs when firms employ resources to produce goods and services that provide the maximum benefit to society. An important condition for allocative efficiency is that prices for services reflect the opportunity cost of resources used in their production. Allocative efficiency is best achieved through competitive markets, or where such competition is not possible, through effective regulation.

As stated in the DRP the underlying economic concept for DORC is that the DORC-based tariffs mimic the discipline of an *efficient* market. Hence, re-valuing the asset base could ensure allocative efficiency to the extent that the regulated tariffs are never set at a level that is inconsistent with competitive market outcomes.

Gold plating/Averch-Johnson

A final reason for choosing to re-value the asset base of a TNSP is to help address over investment. It's argued that rate of return regulated firms have an incentive to over-capitalise which could encourage gold plating and result in the Averch-Johnson affect. The Averch-Johnson affect occurs when the regulated firm determines its input mix by considering both the productivity per dollar of capital and the effect that an expansion of the capital stock will have on the rate base. Increasing capital use has the additional beneficial effect of raising allowable profits. The profit maximising mix of inputs for a regulated monopolist is thus skewed towards capital goods when compared to its unregulated counterpart, because capital is made relatively cheaper.

It should also be noted that if the Commission gets the WACC and other costs right revaluation of the asset base is the best solution in addressing the problem of over-capitalisation.

Reasons not to revalue the asset base on a periodic basis

There are a number of consequences with revaluing the asset base on a periodic basis:

- investment could be deterred as there is a possibility that the TNSP might lose some value of its capital expenditure;

- it may slow down the rate of new investment as it generates uncertainty;

- the TNSP might be encouraged to manipulate the information available to the regulator, so that the expected revaluation is systematically higher than the end-of-period RAB;

- revaluation in the aim of addressing gold plating may be considered too heavy handed when instruments such as the Regulatory Test is already in place; and

- revaluation can result in a number of subjective choices being made. Refer to section 3.3.2 for issues in relation to the number of subjective choices embodied in DORC.

Capital expenditure may not be compensated

A further potential in deterring investment is that the asset base revaluation may result in the TNSP losing some value from its capital expenditure. Capital expenditure can be divided into two categories: (a) capital expenditure which creates enhances or extends the regulated firm's asset, and (b) capital expenditure which merely maintains, renews or refurbishes an existing asset.

In the case of capital expenditure which creates, enhances or extends the asset, since the expenditure is changing the scale or facilities of the underlying asset the expenditure will have some impact on the corresponding replacement cost of an equivalent asset. However, factors such as technological change might have an impact on the replacement cost over time, i.e. technology may increase which results in a downward loss for the TNSP when the asset is revalued. The TNSP would not be compensated for the downward loss through depreciation.

Capital expenditure which merely renews or refurbishes an existing asset, although a legitimate capital expenditure, does not necessarily affect the cost of buying a modern equivalent asset – replacing the engine in a used car may be necessary expenditure but it does not change the cost of buying a new car.

Given the risk that the TNSP might not be compensated for all its refurbishment capex, the TNSP will either significantly reduce its refurbishment capex or to the extent possible, reclassify its refurbishment capex as opex. Expensing the refurbishment capex can result in a lumpy revenue profile and bypass the intention of allocating capital costs across the period of usefulness of the expenditure. This would result in allocative inefficiency between customers who might use the asset over different periods in the asset's life.[10]

Deterrence of new investment

Revaluation on a periodic basis could potentially lead to significant variations in the value of the asset base from one period to the next. Hence, the TNSP could face an unpredictable revenue stream. Volatility of revenue increases the value of the "option to wait" and thus slows the rate of new investment.

The reasoning underlying this argument is as follows. Once an apparently acceptable investment has been identified, the firm must decide whether to invest immediately or wait. In the case of revaluation the firm might wait to invest under the threat of its assets being optimised. Balchin elaborated on this by stating:

> "Whether a transmission business would expect to recover the cost of continuing to provide the service – or expected to earn returns much larger than that required to justify its continued financing of the business – would depend upon the accuracy of the estimated ODRC value, for which substantial statistical uncertainty will be inevitable. The inevitable error reflects the level of uncertainty inherent in each of the steps undertaken to estimate an ODRC value – including, amongst other things, the appropriate extent of optimisation and pre-building of the network, the cost of constructing the hypothetical assets given the unique characteristics of each network, the cost of purchasing equipment

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10 The Commission already has recognised the risk of refurbishment expenditure not being fully compensated for when the asset base is re-valued. In the Victorian Transmission Network Revenue Cap Decision (SPI PowerNet) and the South Australian Transmission Network Revenue Cap Decision (ElectraNet), both TNSPs stated that in the absence of an indication from the Commission as to how it intends the RAB to be set from 2008, it must request that all refurbishment capex in its application be reclassified as opex. Each TNSP stated it would take this measure as a means of protecting its investment.

The Commission stated that it intended to preserve its options regarding the treatment of the RAB from 2008 and was therefore not in a position to give a binding undertaking at this time. However, it did recognise the need for SPI PowerNet and ElectraNet to manage its risks, including the risk of optimisation. Therefore, the Commission quarantined the amount against optimisation for 10 years and depreciated the amount over the same period, recognising that its value may be extinguished well before the life of the original asset.

The quarantining of capex was subject to the condition that SPI PowerNet and ElectraNet undertakes appropriate regulatory evaluation procedures similar to those for other new investments before spending (for example, the regulatory test) and maintains records in such a way that the refurbishment can be identified.

which may fluctuate substantially over time, and the prediction of the future cost of operating, maintaining and renewing the optimal asset".[11]

The cost of waiting is the immediate net cash flows foregone, but the benefit is the extra information arising while waiting and thus a better based (more likely correct) decision. In theory, investment should occur only when the expected benefits from waiting are exceeded by the expected cash flows foregone (both measured in PV terms). The greater the volatility of earnings, the greater the expected (average) benefits from waiting, and thus the slower the rate of investment. From this perspective, asset owners should be wary of re-valuing the asset base. It adds to the risk of their investments and causes them to forego cash (returns on capital) while waiting for successful investments to reveal themselves as sufficiently certain.

Revaluation creates uncertainty not just for the TNSP but also the end user. The end user has no ability to control or mitigate the risks of price shocks that could result from revaluation. These risks are spread across the end user and the future user. A revaluation might result in a windfall gain or downward loss for the TNSP. If for example the benefit of new technology resulted in a downward valuation for the TNSPs' asset base, the reduction in costs would be seen by future users whereas existing users would pay for the reduction in value of assets via depreciation charges over five years.

Information Asymmetry

The revaluation process does not just involve downside risk for the TNSP. The revaluation process might encourage the regulated firm to manipulate the information available to the regulator, so that the expected revaluation is systematically higher than the end-of-period RAB. It would be logical for these factors to create a systematic bias in the valuation assessment towards the TNSPs' interests. More frequent revaluations could compound the impact of any such systematic bias that existed.

Balchin highlighted the information asymmetry problem associated with revaluations:

"A further consideration for the Commission when assessing the relative merits of the two methodologies for updating assets over time is the extent to which the application of the relevant methodology is dependent upon information that is held by the regulated entity. The development of external benchmark models – like engineering cost estimation models – was driven by a concern to overcome the asymmetry of information between the regulator and regulated entity. However, the practical application of the ODRC methodology as discussed above implies that the Commission would be dependent upon information that is held by the regulated entity.

"To date, the estimates of the ODRC value of regulated assets in both the electricity and gas industries have been produced by owners of the regulated assets (or their representatives), and the regulators' analyses typically has been limited to a desk-top analysis of the main assumptions reflected in those estimates. If regulatory values for regulated electricity transmission assets are to be reset at

11 Jeff Blachin , August 2003, Methodology for updating the Regulatory Value of Electricity Transmission assets, Attachment A to the Discussion Paper, pp 38.

their estimated ODRC value over time, it would be expected that the Commission would need to take on a more active role in the derivation of the ODRC estimates".[12]

Regulatory Test for capital expenditure

The Commission relies on the TNSP applying the regulatory test which is a cost/benefit analysis test used by regulated transmission and distribution networks to assess the economic efficiency of an investment. If the Commission were to revalue the asset base and apply the regulatory test in order to determine the revenue cap it might be considered too heavy handed.

As noted if the Commission gets the WACC and other costs right revaluation of the asset base is the best solution in addressing the problem of over-capitalisation.

3.3.2 Option 2 – Lock-in jurisdictional asset base

Reasons to lock-in the jurisdictional asset base

There are a number of reasons as to why the Commission might wish to lock-in the jurisdictional asset valuation and roll in new investment at cost:

- this approach is consistent with the Commission's approach in gas;
- addresses the potential risk to investment of periodic revaluation;
- it would avoid subjectivity. The DORC valuations embody multiple subjective choices; and
- allocative efficiency might not be a concern in the electricity industry.

Approach is consistent with the Commission's approach in gas

If the Commission adopted the approach to lock-in the jurisdictional asset base it would provide consistency with the approach in gas. The Commission has endeavoured to maintain a certain amount of consistency between gas and electricity. This is evident in the choice of financial parameters, treatment of opex and most other elements of the building block. In saying this however it is important to note that the Commission cannot set in stone a particular approach to valuation. The Commission in unable to do this, as the Code provides it with the discretion to re-value the asset base at the next regulatory re-set. This is quite distinct from the National Third Party Access Code for Natural Gas Pipeline Systems (the gas code) which actually prohibits revisions to the initial capital base.

[12] Jeff Blachin , August 2003, Methodology for updating the Regulatory Value of Electricity Transmission assets, Attachment A to the Discussion Paper, pp 24.

Does not deter new investment

As noted in section 3.3.1 revaluation of the asset base on a periodic basis might deter new investment. This uncertainty is not generated when the regulator simply rolls in new investment at cost which is subjected to the application of the regulatory test.

Avoids subjectivity

In locking-in the jurisdictional asset base, the TNSP avoids the multiple of subjective choices that embody DORC. Decisions about replacement costs, depreciation schedules, estimates of useful life, engineering criteria and asset aggregation, amongst others will all impact on the DORC valuation.

Allocative efficiency

If the Commission locked in the jurisdictional asset base indefinitely there might be allocative efficiency concerns. For example if there were changes over time with technology in the electricity industry regulated tariffs would be set at a level above the value that would be reflected in an *efficient* market.

However, such changes can be addressed where the Commission uses its discretion by adopting an annuity depreciation scheme to take account of the technological changes resulting in prices that mimic the behaviour of a competitive market.

Further, there is a question regarding how stable factors such as technological change, costs and environment might be in the electricity industry.

Sinclair Knight and Merz (SKM)[13] stated that factors such as technological change in the electricity market have not significantly decreased the optimised replacement cost of the network. Technological changes have resulted in the asset owners being able to work existing assets harder and hence delay network reinforcement rather than significantly reducing the cost of new assets. As a consequence of the increased utilisation of the network, use of these new technologies will not necessarily result in a significantly lower cost of an optimised network.

Further, SKM[14] considered that the risk of "bypass" is minimal in the electricity industry. The cost of bypass assets might in fact become more expensive than the existing network historic costs because of the impact of external constraints making new installations in urban/CBD areas difficult. Such an outcome counters the trend to lower costs due to cheaper raw materials and labour productivity gains. On this basis, a revaluation of assets in the future could be expected to result in a more expensive outcome (in real terms) than historically for urban/CBD assets and a cheaper outcome for rural assets. Over time, these differences will compound and become significant.

13 Sinclair Knight Merz, May 2002, Review of Re-valuation versus Roll-Forward, ACCC website.
14 *Ibid.*

"Averaging Price Affect"

Even if allocative efficiency is a concern it might not be an issue given that the very nature of the TNSPs' asset base results in a smooth price path. This smooth price path occurs as new investment is rolled into the asset base at optimised replacement costs, while sunk assets drop out of the asset base.

Reasons not to lock-in the asset base

There are a number of consequences with locking-in the jurisdictional asset base and rolling in new investment at cost:

- as mentioned the Commission has never undertaken a full valuation of any of the TNSP's assets. If the Commission did not revalue the asset base it would mean any errors in the asset base will be perpetuated into the future. Hence, the Commission would be neglecting one of its main responsibilities under the Code, which is to ensure that an efficient rate of return is generated;

- allocative efficiency concerns arise where changes in technology in the electricity industry may result in regulated tariffs being set at a level above the value that would be reflected in an *efficient* market; and

- with a lock-in approach there is a tendency for firms to choose a capital/labour ratio which is higher than efficient for the level of output produced by the firm.

It is important to note that if the Commission were to lock-in the asset base, it would lock-in both the fixed assets and the easements.

3.3.3 Option 3 – One off revaluation of the asset base and then lock-in

The main reason why the Commission would conduct a one off revaluation of the jurisdictional asset base and then lock-in would be if the Commission considered that the jurisdictional asset base inappropriate. For the more detailed arguments as to why the Commission would or would not lock-in the jurisdictional asset base see section 3.3.2.

As noted, the Commission if it were to revalue the asset base would revalue the fixed assets using a DORC methodology but might revalue the easements using either the DORC or historic cost methodology. Further, if the Commission were to lock-in the asset base, it would lock-in both the fixed assets and easements.

3.4 The Commission's preferred position

The Commission recognises that the Code gives it discretion to revalue the asset base in the next regulatory reset. The Commission's initial view is to consider each revenue cap on a case by case basis but with the preferred position to lock-in at this stage, as there is no evidence to suggest that there are significant problems with the jurisdictional valuations. The Commission points out that the asset base includes both fixed assets and easements.

The Commission's preferred position is supported by Balchin, who stated:

> "Having regard to the merits of the ODRC methodology relative to rolling forward the asset base, we do not consider revaluations based on ODRC to be feasible in the short-term nor does it provide appropriate incentives for regulated transmission providers over the longer term. A preferred approach is for the regulatory asset base to reflect the level of capital expenditure undertaken and return of funds received over the regulatory period – that is, the rolling forward methodology".

The Commission's preliminary view is that there doesn't appear to be a strong case for conducting a one off revaluation of the asset base. At the outset there are no obvious reasons as to why the jurisdictional asset base would be inappropriate. Further, the Commission's preliminary view is that there are no compelling arguments for re-valuing the asset base in the near future. For example, there does not appear to be any major allocative efficiency concerns.

In contrast, the Commission's initial view is that there are a number of positive outcomes from locking-in the jurisdictional asset base. The main reasons are that a lock-in does not generate the uncertainty and deter investment as a revaluation might. In addition, the Commission avoids the multiple of subjective choices that is embodied in the DORC valuation.

The Commission's preferred position

The Commission's initial view is to consider each revenue cap on a case by case basis but with the preferred position to lock-in at this stage, as there is no evidence to suggest that there are significant problems with the jurisdictional valuations. The Commission notes that the asset base includes both fixed assets and easements.

The Commission's preferred position is to lock-in the asset base but if option 1 or 3 is adopted the Commission is likely to adopt historical cost when revaluing easements. Refer to section 3.6 for further discussion on easements.

<u>Three main options for consideration</u>

The Commission would like interested parties to comment on the three options:

- Revalue assets on a periodic basis (for example each five-year regulatory period) using the ODRC methodology;
- In each regulatory period the rate base is determined by adopting the initial jurisdictional valuation and adding in new investment at cost; and
- One off revaluation of the jurisdictional asset base using DORC, however, in subsequent regulatory periods the Commission will simply roll in new investment at cost.

In addition, to the three options for consideration the Commission would like interested parties to consider a number of issues:

- Is the jurisdictional asset base appropriate for regulatory purposes?
- Currently, the Commission cannot rule out revaluation as the Code provides the Commission to revalue the asset base. Are there any advantages to changing the Code?
- Should the Commission change the Code to provide consistency between the gas and electricity code?
- Should the Commission lock-in the asset base and not revalue under any circumstances?
- Under what certain specified circumstances should the Commission revalue the asset base?
- Should the Commission compensate through depreciation if it were to revalue?
- How stable is technology, costs and environment n the electricity industry?

3.5 DORC implementation

The Commission's preferred option is not to revalue the asset base, however, if the Commission decided to revalue there are a number of implementation issues with DORC.

Optimisation

Optimisation removes assets that are redundant or may be by-passed. Optimisation may provide for the removal of an amount from the asset base to:

- ensure that assets which cease to contribute in any way to the delivery of services are not reflected in the asset base; and

- share costs associated with a decline in capacity on that part of the network.

There are a number of merits and problems in relation to optimisation regarding the configuration of the system and timing issues.

Issues for consideration in regard to optimisation

The Commission would like interested parties to comment on the merits and problems with the optimisation process. Further, the Commission would like interested parties when assessing the optimisation process to take into consideration a number of questions:

- By what engineering criteria is an asset or arbitrary grouping of assets optimised?

- How far is the engineer allowed to go in hypothetically re-designing the asset base?

- What customer base (throughput) is relevant, is it the current situation or a projection of demand in 5 or 25 years time?

- Does the notion of asset optimisation relate only to cost or more to a set of engineering parameters?

- If both, which should be given more emphasis?[15]

Replacement Costs (RC)

The actual magnitude of replacement costs results from the combined effects of:

- improved efficiencies associated with an increase in technology; and

- changes in manufacture and installation costs i.e. changes in the exchange rate.

Normally, these factors determine the valuation placed on the RC. However, there are a number of difficult issues involved in determining exactly what the RC is.

[13] Johnstone, David, (December 2001), Replacement Cost Asset Valuation and Regulation of Energy Infrastructure Tariffs.

Issues for consideration in regard to replacement cost

The Commission would like interested parties to comment on assessing what is the RC. Further, the Commission would like interested parties when assessing what the RC is to take into consideration a number of questions:

- What is the assets' RC? Is it the physical item in question (i.e. the transmission tower) or its modern equivalent alternative?
- What conditions should the regulator assume already exists? Should RC be calculated on the basis that 'brownfields conditions' exist where basic existing infrastructure is already in place, or should they be calculated on the basis of 'greenfields' assumptions so that the replacement of transmission system assets would therefore not need to work around such structures?
- Finally, if the regulator decided to revalue the asset, would it revalue every asset or group some assets together when re-valuing?

Depreciation

The Commission has traditionally adopted DORC as the Optimised Replacement Cost (ORC) multiplied by the ratio of the existing TNSP's assets remaining useful life over the useful life of a new asset. The way in which depreciation is handled is of great importance, particularly in regard to any incorporation of accelerated depreciation either due to technological obsolescence or due to stranding (i.e. economic obsolescence). The depreciation profile chosen will have an impact on the DORC valuation. For example, a front-loaded profile would result in a higher DORC valuation whereas an escalating profile would result in a lower DORC valuation.

The Commission always has the discretion to adopt an annuity depreciation scheme which can respond to the associated pricing changes in replacement cost taking account of general price increases and technological change in a manner which mimics competitive market behaviour. However, the Commission's initial view is that factors such as technological change do not have major impacts in the electricity industry. Therefore, a straight-line approach for the electricity industry is easier to implement and gives rise to clearer incentives for efficient investment then alternatives such as annuity depreciation.

Issues for consideration in regard to depreciation

The Commission would like interested parties to comment on the use of straight-line depreciation. Further, the Commission would like interested parties when assessing the use of depreciation to take into consideration a number of questions:

- Should the Commission adopt an annuity depreciation scheme to take into account factors such as technology, costs and environment in the electricity industry? If so what rate of change is appropriate?
- Is by-pass risk a concern in the electricity industry?

3.6 Easements

Specific issues in regard to revaluation for easements

There are a number of specific issues relevant just to easements in the light of revaluation. Given its unique characteristics the Commission might treat easements differently to other assets for which DORC may be a more suitable methodology.

Why are easements different?

There are a number of reasons why easements have been regarded as different to other assets for the purposes of valuation include:

- there does not appear to be a market in which easements are sold or traded which restricts the use of market based valuations for easements. The fact that easements have restrictions regarding how they may be used by potential acquirers is another limitation on an assumed market

- to determine replacement costs according to the deprival value to the owner of the land over which an easement has been created appears inappropriate given that it represents the owner's deprival value, not that of the TNSP

- depreciation is an important feature of DORC valuations given that the depreciation schedule can have a substantial effect on the valuation result. Given that easements do not need to be replaced, assigning a deprecation schedule to them raises problems of potentially large variations in results based on the arbitrary choice of depreciation schedule. However, to not depreciate easements could lead to problems of TNSPs' not recovering the full expenditure of the assessed value of easements

- the fact that easement acquisition is backed by compulsory acquisition legislation means that valuations that assume free negotiation between two parties in a market could produce inaccurate results

- valuations which require estimates of land values, market based or based on costs of easement acquisition can contain a large margin for error given the many subjective judgements involved in valuing easements.

These characteristics mean that it may be inappropriate to value easements according to the DORC methodology which applies to other TNSP assets.

What is the most appropriate asset valuation methodology for easements?

It should be noted that the Commission is only considering adopting the DORC approach for fixed assets when revaluing the asset base, however, for easements given its unique characteristics the Commission is considering both historical cost valuations and replacement cost valuations.

Historical cost valuations

Historical cost valuations would use the TNSPs' actual expenditure incurred when acquiring easements to arrive at easement values. Most TNSPs have records of the costs incurred in the process of acquiring easements and these could be used to establish historical cost valuations. Such a process was used in establishing several jurisdictional valuations.

The benefits of this approach would be that it would accurately compensate TNSPs for their expenditure on easements, be relatively easy to determine a figure, and may maintain continuity with jurisdictional valuations where historical cost valuations were used by the jurisdictions.

A variant on the historical cost approach is to use a benchmark approach. This would establish benchmarked costs for TNSPs' easements based on a TNSP's own records for those TNSPs with relatively complete records, and then impute a value to cover easements for which records are unavailable or incomplete.

The benefits of this approach are similar to the benefits of historical cost valuations with the addition of the benefit that the benchmark approach would deliver values for TNSPs which lack historical records. This approach would also maintain consistency between the valuation methods used for TNSPs.

Two relevant issues with regard to historical cost are whether the historical cost of easements should be depreciated. This could be undertaken according to a depreciation schedule related to the life of the asset for which the easement was initially acquired or another method. The second issue is whether the historical cost should be indexed in any way.

Replacement cost valuations

A replacement cost valuation would attempt to establish the cost of replicating (acquiring) the easement assets in question at a contemporary value.

In order to take into account returns that TNSPs have already received on easement assets, the replacement cost of easements could be depreciated in line with the transmission asset for which they had been purchased. This would ensure that TNSPs were not overcompensated for expenditure on easement assets.

A (depreciated) replacement cost approach could be optimised to provide a DORC valuation. Optimisation would establish a valuation for the most efficient contemporary acquisition of easements. Different levels of optimisation could be chosen including a full reconfiguration of the network, changes to legislation, and changes to technology.

The advantages of the depreciated replacement cost approach would be that it establishes a uniform methodology for all TNSPs, and provides some link to new entrant costs given that it provides a valuation linked to the acquisition costs of easement rights.

Specific issues interested parties may wish to consider could be:

- whether and how easements should be optimised and if so according to what factors

- whether new and/or existing easement expenditure should be depreciated, and if so according to what depreciation schedule.

Optimisation and depreciation of easements

The Commission seeks comment on whether and how easements should be optimised or depreciated.

3.6.1 The Commission's preferred position

The Commission's preferred option is not to revalue the asset base; however, if the Commission decided to revalue the asset base (using a DORC methodology for fixed assets) it sees merit in adopting an historical cost approach for easements.

If historical cost cannot be established for easements then a benchmarked approach would be adopted.

The Commission believes that the proposed valuation methodologies for easements meet the objectives and principles of the Code.

New investment in easements would be valued at efficient acquisition cost which would promote efficiency in TNSPs' operations. By recognising and providing a return on TNSPs' easement expenditure the Commission would ensure that TNSPs have an incentive to continue to invest.

Valuing existing easements at historic cost would ensure that TNSPs were fully and accurately compensated for their expenditure on easements. This would protect investors from windfall losses that might result from valuations which were too low. This method would also protect electricity customers from valuations which were higher than TNSPs' actual spending on easements.

The Commission's preferred position

The Commission's preferred option is not to revalue the asset base; however, if the Commission decided to revalue the asset base (using a DORC methodology for fixed assets) it sees merit in adopting an historical cost approach for easements.

Two main options for consideration in regard to easements

The Commission seeks comment on its preferred position regarding its two options, DORC or historic cost for revaluing existing easements.

4 Capital Expenditure

4.1 What is the issue?

Capital expenditure (Capex) is one of the biggest drivers of a TNSPs' regulated revenue requirement. The Code is non-prescriptive in regard to how, new or proposed capex should be reflected in the regulatory asset base. However, capital investment decisions will proceed if they satisfy the regulatory test, which is the mechanism set out in the code to assess the economic efficiency of investment decisions.

In determining the revenue requirement at the regulatory reset, the Commission will examine capex from two perspectives. Firstly the Commission will conduct an assessment of the reasonableness and efficiency of a TNSPs' proposed capex program for the forthcoming regulatory period considering future demand growth, generating patterns, network limitations and any other relevant information. Secondly the Commission will consider differences between the forecast capex allowance approved in the previous revenue cap decision with the actual capex undertaken by a TNSP considering all relevant information for any variations between the two.

4.1.2 What is capital expenditure?

An issue that the Commission has been confronted with in its previous revenue cap decisions is distinguishing between capex and opex. The Commission notes that there is a relationship between capital and opex, and recognises that there is a potential for businesses to trade-off or substitute opex for capex, in recognition of higher returns for capex.

In classifying capex and opex, the Commission will refer to the appropriate and relevant accounting standards and accounting concepts. The Commission considers that the use of the accounting standards to determine and distinguish between capex and opex is appropriate given that these standards have been tested and applied. Furthermore, this will provide consistency with a TNSPs accounting treatment of expenditure in their accounts.

Generally, the Commission considers that capex falls into three broad categories:

- Asset replacement (replacing services that have passed their service date);
- Asset refurbishment (that is prolonging the life of an asset); and
- Asset augmentation (works to enlarge a *network* or to increase the capability of a *network*).

4.2 How has the Commission dealt with reviewing capex in the past?

Draft Regulatory Principles

In the DRP the Commission noted that there is a dilemma as to how actual and forecast capex should be treated at the start of the regulatory period given knowledge of forecast and actual capex from the previous regulatory period and forecast capex for the next regulatory period.

Accordingly, the Commission noted that it would:

- At the start of the regulatory period roll into the asset base projected capex for the regulatory period when it is scheduled to become operational.
- In relation to capex at the start of the next regulatory period for the previous regulatory period, the Commission proposes that only actual capital expenditure since the previous review be included in the asset base.[16]

At the regulatory reset the Commission noted that it would consider reviewing the prudency of large capital expenditures and may seek assurances that the TNSP has complied with the requirements of clause 5.6 of the code.[17]

The Commission acknowledged that this may encourage the entity to spend what has been allowed, knowing that it will earn a return and not seek to achieve efficiencies in capital expenditure.

Therefore, the Commission stated it would use the prudency test as outlined in the gas code, to determine whether the capex spent was efficient. Under the Gas Code, new facilities investment must pass a prudent investment test if it is to be included in the regulatory asset base. In particular, section 8.16 of the Gas Code states:

The amount by which the Capital Base may be increased is the amount of the capital cost incurred (***New Facilities Investment***) provided that:

a) The amount does not exceed the amount that would be invested by a prudent Service Provider acting efficiently, in accordance with accepted good industry practice, and to achieve the lowest cost of delivering services; and

b) that one of the following conditions is satisfied:
   i. the Anticipated Incremental Revenue generated by the New Facility exceeds the New Facilities Investment; or
   ii. the Service Provider and/or Users satisfy the Relevant Regulator that the New Facility has system-wide benefits that, in the Relevant Regulator's opinion, justify the approval of the higher Reference Tariff for all Users; or
   iii. the New Facility is necessary to maintain the safety, integrity or Contracted Capacity of Services.

The Gas Code further states in section 8.17 that:

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16 Draft Statement of Regulatory Principles, p55.

17 The Commission notes that since the time of the writing of the DRP, 5.6 of the code has been amended.

For the purpose of administrating section 8.16 (a), the relevant regulator must consider:

a) whether the New Facility exhibits economies of scale or scope and the increments in which Capacity can be added; and
b) whether the lowest sustainable cost of delivering Services over a reasonable time frame may require the installation of a New Facility with Capacity sufficient to meet forecast sales of Services over the time frame.

Regulatory Test

As previously noted, the process for assessing capex as outlined in the DRP is based on the principles outlined in the Gas Code. This is due to the DRP being released prior to the promulgation of the regulatory test by the Commission. The regulatory test, which is based on a traditional cost-benefit analysis methodology, is used by TNSPs to assess the economic efficiency of augmentations. A project satisfies the regulatory test if it maximises the net benefits to the market, or in the case of reliability augmentations, minimises the cost to the market.

While the DRP refers to the process set out in chapter 5 of the code, it does not explicitly recognise that TNSP's are required to apply the regulatory test to augmentations. It states, however, that a prudency test would be used by the Commission to review a TNSP's capex program in a manner that is consistent with a TNSP's use of the regulatory test. As a result, the Commission believes that it is appropriate that it only considers a TNSP's capex program by having regard to the regulatory test.

4.2.1 Why Change?

The Commission now believes a more detailed review process needs to be set out in the DRP, which recognises that TNSPs must apply the *regulatory test*[18]during the regulatory period.

As was noted by the Commission in its discussion paper on the *regulatory test*, a TNSP is only required to apply the *regulatory test* to new augmentation. Refurbishment and replacement works are not required to be assessed against the regulatory test.

The Commission therefore proposes to develop a more rigorous process that TNSPs must adopt when assessing non-augmentation capex which is consistent with the methodology outlined in the *regulatory test*. The Commission would prefer that a capex test be applied by the TNSP during the regulatory control period as the capex is undertaken. The Commission is aware that it cannot compel TNSPs to apply such a test during the regulatory control period. However, the Commission considers that if a TNSP is aware of the criteria that the Commission would employ to assess capex for the purpose of rolling it into the regulatory asset base then the TNSP would adopt similar criteria. TNSPs who voluntarily assess replacement or refurbishment capital expenditure against the regulatory test will not face optimisation risk.

18 Under the Code, the regulatory test is to be applied to capital works that augment the network.

When assessing a TNSP's proposed capex program, the Commission will assess the likelihood that proposed augmentation capex will pass the regulatory test. This includes giving due consideration to the net benefits or relevant code provisions, project costings and timing of construction.

At the regulatory reset the Commission will conduct a review on whether the regulatory test application was conducted in accordance with the process and methodology outlined in the regulatory test. In particular it will consider whether the alternatives were justifiably excluded, whether the costing for the alternative projects were in accordance with industry best practice and whether the timing of the construction was appropriate.

In its review of a TNSP's actual expenditure, the Commission would anticipate that the cost at which a project satisfies the regulatory test may differ from the actual construction cost. The Commission is seeking the views of interested parties on the best approach to deal with this issue.

Value at which capex should be rolled in to the asset base

Comments are invited on the proposed changes and whether or not the capex amount to be rolled into the asset base should be based on the outcome of the regulatory test, or based on actual build costs.

At the regulatory reset, the Commission will conduct a review of any capital expenditure undertaken by the TNSP that has not passed the *regulatory test* with a view to making any necessary adjustment to the maximum allowable revenue in the next regulatory period.

Also the Commission notes that it is possible that a TNSP may or may not spend the full allocation of capex from the previous revenue cap decision. The changes may be caused by unforseen increases or decreases in demand. An inappropriate regime to deal with these changes may adversely affect the incentives that a TNSP has to invest in its network.

Under or over spends on the allowed capex from the previous period

The Commission is seeking views from interested parties on how the Commission should deal with under or overspend on the allowed capex from the previous period.

The Commission notes that there may be alternative approaches to assess capex, such as the use of benchmarks.

Alternatives approaches to assessing capex such as benchmarks

The Commission is seeking views from interested parties on what these alternatives may be.

Benchmarking is one such alternative but there are a number of implementation issues with benchmarking that need to be resolved before the Commission could adopt such an approach. This issue is discussed in section 6 of this paper.

Benchmarking

The Commission would like interested parties to comment on the merits and problems with benchmarking. Further, the Commission would like interested parties when assessing benchmarking to take into consideration a number of questions:

- Should the Commission apply benchmarking to individual components of the total allowed revenue (such as capital expenditure)? In your view is benchmarking of capex feasible or sensible?

- What are the primary cost drivers of electricity transmission companies? Is it possible to develop a reasonably reliable cost model for Australian electricity transmission companies?

- Supposing the Commission is able to develop a reasonably reliable cost model for transmission companies, how should the Commission use the output of this model?

4.3 The Commission's preferred position

The Commissions preferred position is when assessing a TNSP's proposed capex program, the Commission will assess the likelihood that the proposed capex projects for both augmentations and non-augmentations will pass the regulatory test.

At the regulatory reset the Commission will conduct a review of whether the regulatory test applications were conducted in accordance with the process and methodology outlined in the regulatory test.

The Commission's preferred position

The Commission's preferred position is to adopt the regulatory test when assessing and reviewing revenue proposals associated with augmentation and non-augmentation capex programs.

- TNSPs who voluntarily assess replacement or refurbishment capital expenditure against the regulatory test will not face optimisation risk.

5 Operating and maintenance expenditure

5.1 What is the issue?

The Commission is reviewing its current approach to ensure that the TNSP is acting efficiently to achieve the lowest sustainable cost of delivering electricity. The Commission receives a proposal from the service provider of its forecast actual costs. The Commission then uses a combination of performance indicators to assess the efficiency of the firm's costs such as historical performance and forward-looking assessment of cost drivers. The Commission appoints a consultant who in turn assesses the TNSP's proposal. The Commission relies heavily on the consultant's findings when making its own assessment of the TNSP's costs.

The Commission's objective is to improve the incentives for TNSPs to reduce costs, but also making sure that the TNSP is adequately compensated for the costs they accrue. As a means of achieving greater incentives the Commission uses an efficiency carry-over. The efficiency carry-over mechanism rewards the TNSP with higher profits when the firm manages to lower its controllable costs.

The Commission is now considering making greater use of external benchmarks for setting the price and revenue cap parameters. The Commission considers that this may result in more efficient practice, as benchmarking breaks the nexus between the firm's actual costs and revenues.

Self-insurance risks and pass-through

In some cases, TNSPs face specific risks and may wish to be compensated for managing the risk through an opex allowance. Specific risks stem from the fact that many of the issues surrounding an individual company are peculiar to that company and perhaps immediate competitors. In general if the risk is symmetric i.e. same probability as upside and downside, an opex allowance would not be needed. In other cases, where the risk is not symmetric an opex allowance in terms of self-insurance or pass-through would be appropriate. Self-insurance risk and pass-through will be discussed later on in the paper.

There are risks (generally known as market risk) that cannot be diversified. Market risk stems from the fact that there are economy wide factors which affect all businesses, such as recessions and inflation. However, these risks are covered by the weighted average cost of capital (WACC) rather than an opex allowance, (see section 8 of this paper).

5.2 How has the Commission dealt with opex to date?

The Commission's current approach to dealing with opex is to review the TNSPs' proposed forecasted opex by considering a combination of performance indicators based on historical performance, international benchmarks and forward-looking assessment of cost drivers. In making its judgement the Commission is conscious of the limitations of the measures used. For example, the Commission conducts some benchmarking exercises but this is on the basis of a sanity check rather then the objective of achieving quantifiable efficiency measures.

In order to assist its judgement, the Commission relies heavily on appointed consultants who analyse and comment on a number of matters in relation to the contribution of opex to the TNSPs' delivery of transmission services. These matters range from:

- benchmarking the TNSPs' opex forecasts against other TNSPs both nationally and internationally;
- conducting an assessment of the TNSPs' forecast opex costs for each year of the regulatory period and whether there is scope for additional efficiency gains;
- reviewing the TNSPs' allocation of opex costs to specific activities i.e. the distinctions between regulated and non-regulated activities; and
- assessing the efficiency of the TNSPs' operating practices and management systems.

As a means of achieving greater incentives the Commission uses an efficiency carry-over. The efficiency carry-over mechanism rewards the TNSP with higher profits when the firm manages to lower its controllable costs.

5.3 Why change?

The Commission notes there is a high degree of information asymmetry with the process outlined above. The firm's actual costs can differ from the forecast costs, as they depend on factors such as the level of cost-reducing effort, the quantity and quality of output, the price of inputs, changes in technology, weather and other random events (such as accidents) and the age and quality of capital stock. The TNSP is far more aware of its own true costs, and, hence, the Commission relies heavily on the TNSP providing as much information as possible.

Given the Commission's reliance on the information provided by the TNSP, there is an incentive for the TNSP to game the regulator by over forecasting their expected costs.

Over time the Commission does obtain additional information about the firm's actual costs. The regulatory period is usually five years, hence, the Commission at the next regulatory reset will know what the firm's actual costs were over the last five years. This does give the Commission an indication about what the TNSP's actual costs over the next five years will be. However, in the future new factors emerge that affect the firm's opex costs which could not have been predicted from the firm's past opex.

The Commission considers that such an approach in assessing the TNSP's opex is a useful one but imperfect, given, that the review process is backward looking, not forward looking. Further, such a review process may be unsatisfactory for the TNSP as well, from the view point that the approach can be intrusive and information intensive.

The question is whether these regulatory regimes can be improved by providing stronger incentives for efficiency and investment with a more light-handed regulatory approach. A recent workshop on incentive regulation explored the greater use of external benchmarks, such as total factor productivity measures for setting the price and revenue cap parameters. The Commission considers that this may result in more efficient practice, as benchmarking breaks the nexus with the firm's actual costs and revenues.

However there are a number of implementation issues with benchmarking that need to be resolved before the Commission could adopt such an approach (see section 7 of the discussion paper).

Benchmarking

The Commission would like interested parties to comment on the merits and problems with benchmarking. Further, the Commission would like interested parties when assessing benchmarking to take into consideration a number of questions:

- Should the Commission apply benchmarking to individual components of the total allowed revenue (such as operating expenditure)? In your view is benchmarking of opex feasible or sensible?

- What are the primary cost drivers of electricity transmission companies? Is it possible to develop a reasonably reliable cost model for Australian electricity transmission companies?

- Supposing the Commission is able to develop a reasonably reliable cost model for transmission companies, how should the Commission use the output of this model?

In the interim the Commission will continue to forecast the actual costs of the firm and using the efficiency carry-over mechanism as a means of achieving greater efficiency.

The Commission considers that in regard to implementing an efficiency carry-over for opex, the implementation issues are not a major concern. The Commission is more concerned over the distortions that might be created if it does not provide the right incentives for both opex and capex. For example, if the Commission were to implement an efficiency carry-over just for opex, will this result in a substitution affect between opex and capex? (see section 6 of this paper for a discussion of this issue).

Incentive Mechanism

The Commission would like interested parties to comment on the merits and problems with an efficiency carry-over mechanism. Further, the Commission would like interested parties when assessing the efficiency carry-over to take into consideration a number of questions:

- If the Commission were to specify an incentive mechanism in the statement of regulatory principles, what criteria should that incentive mechanism satisfy?
- How important is it that the power of incentives be constant over time?
- How important is it that the incentives for capex and opex efficiencies be roughly equal?

5.4 The Commission's preferred position

The Commission considers that benchmarking is a more high powered incentive mechanism as it breaks the nexus with the firm's actual costs and revenues. However, there are a number of implementation issues that need to be resolved and developed before the Commission could adopt such an approach. In the interim the Commission will stay with forecasting the firm's actual costs and using a carry-over mechanism that results in constant incentives and reveals the true costs of the TNSP over time.

The Commission's preferred position

The Commission's preferred position is to rely more on benchmarking in the future when assessing the TNSP's opex costs.

For further discussions regarding incentive regulation and benchmarking refer to section 6 and section 7 respectively of the discussion paper.

Options for achieving the most efficient costs

The Commission would like interested parties to comment on what they consider to be the most effective means of reducing costs:

- the Commission's current approach; or
- benchmarking.

5.5 Self-insurance and pass-through events

5.5.1 What is the issue?

It is the Commission's experience that TNSPs will endeavour to manage their firm specific risks by a number of means including:

- taking out insurance cover
- self-insuring against certain risks
- establishing pass-through rules with the Commission so that their revenue caps can be amended to pass-through the financial impact of designated events to customers.

In the first two cases, TNSPs seek an allowance for the expected insurance costs through their forecast operating and maintenance expenses (opex) claim. In the third case, costs would be passed directly through to the consumer, usually because adequate insurance cover is not available.

Until its recent GasNet and SPI PowerNet revenue cap decisions, the Commission had not been presented with detailed claims for self-insurance allowances or requests for a formal pass-through mechanism for certain costs. However, the Commission's decisions in GasNet and SPI PowerNet have established self-insurance and pass-throughs as acceptable categories of compensation. It is therefore considered timely and appropriate to consider more detailed guidelines relating to these matters for incorporation into the *Statement of Regulatory Principles*.

The following discussion considers two matters:

- the case for including self-insurance allowances and cost pass-throughs under an incentive based regulatory regime; and
- guidelines to ensure that only appropriate self-insurance and pass-through events are incorporated into the revenue caps of TNSPs.

TNSPs and insurance

Like other forms of TNSP expenditure, insurance expenditure is covered by the Commission's incentive regulation approach. Under this approach the firm is required to undertake only the most efficient form of expenditure on insurance (which will usually relate to the cost of the insurance).

There are three types of insurance "cover" that could be available to TNSPs from a regulatory viewpoint:

- external insurance. This is where a TNSP purchases insurance cover from an insurance company and pays a premium for that cover. The advantage of this from a regulatory point of view is that the premium is a market price and is readily verifiable by the Commission, and that the economies of scale and expertise of the insurance company may mean that the insurance cover is a low cost form of insurance

- self insurance. This is where a TNSP pays an insurance premium to itself at a level which has regard to the likelihood of the risk in question and an assessment of its likely cost if that risk eventuates. This type of insurance could have the advantage of avoiding paying for the administration costs and profit of an insurance business were external insurance acquired

- pass-through. A pass-through is where a TNSP does not take out insurance for a particular type of risk but where the consumer pays for the pass-though event (if it occurs) directly through higher charges. A pass-through may be accepted by the Commission if it believes that it is unreasonable for a TNSP to insure against a form of risk.

A key consideration in terms of the proper operation of insurance and pass-throughs for TNSPs is that there is no overlap between the three types of cover. For example, if a TNSP chooses to insure externally against a particular risk then it cannot also claim an allowance for self-insurance for that risk.

Insurance and pass through under the building block approach

Under the building block approach TNSPs are compensated for efficient expenditure on external insurance and self-insurance in the opex category (which may be as much as 25 per cent of a TNSP's annual revenue requirement).

Pass-through arrangements are a new element in the building block approach. Their effect on TNSPs' revenue requirements is unpredictable and unknown at the time the revenue is set. Accordingly, cost pass-throughs are not captured in the elements of the MAR equation.

With cost pass-through arrangements factored into the MAR equation, other elements such as return on capital and the return of capital would form the allowed revenue for the TNSP, and any pass-through amounts would be determined on application by the TNSP, or initiated by the Commission itself. IPART adopts a similar base revenue allowance + pass-through costs approach in determining DNSPs' revenue requirements.

The DRP does not deal with the subject of opex, except in the context of a discussion on benefit sharing as an incentive for making opex cost savings. Similarly, pass-through arrangements are not dealt with in the DRP, which only discusses matters which may lead to the revocation and resetting of the revenue cap during the regulatory control period under clause 6.2.4(d) of the Code, such as a material error in setting the revenue cap.

Moral hazard and insurance

A question raised in the context of insurance coverage for TNSPs is whether TNSPs have a moral hazard issue with regards to insurance. This could occur given that governments might allow TNSPs to pass-through costs (shift the costs of the event onto consumers) even if the TNSP had another form of insurance (external or self-insurance) if the viability of the TNSP were in question.

A TNSP might therefore have an incentive to secure the highest cost but perhaps inadequate insurance cover (external or self insurance), rather than a pass-through for which it receives no revenue allowance, on the assumption that if a large scale damaging event occurs, governments would allow the TNSP to pass-through costs for which it were meant to be insured.

To address this concern, the Commission could have the authority to refuse an application for self-insurance for events that would be more appropriately be dealt with as pass-through events.

Granting allowances relating to self-insurance risks provides incentives for TNSPs to manage their risks and pursue ongoing efficiency gains. Allowing a pass-through of costs relating to specified events addresses matters that may affect the ultimate viability of a TNSP's operations. The following discussion presents the Commission's proposed guidelines in respect of these matters.

5.5.2 How have cost pass-throughs and self-insurance claims been dealt with to date?

Guidelines for dealing with insurance events have been included in various Commission decisions to date:

- external insurance: an allowance for external insurance has been accepted and established in the Commission's decisions since the beginning of its regulation of gas and electricity transmission networks

- self-insurance: an allowance for self-insurance was first made in the GasNet decision (2002). A similar allowance was then granted in the SPI PowerNet decision (2002)

- pass-throughs: the GasNet decision (2002) established the pass-through allowance. This was then granted to SPI PowerNet (2002). In the earlier Powerlink (2001) revenue cap decision it was agreed with the TNSP that pass-throughs for self-insurance and other unspecified events would be considered on a case by case basis where it could be demonstrated that extraordinary contingencies had arisen.

5.5.3 Should the Commission change its approach in dealing with risk management?

Risk management has gained increased prominence in recent years due to greater uncertainty in the external environment. The cost of insurance has risen significantly and some forms of insurance are now virtually unobtainable. Further, TNSPs find that some events, for example terrorism, are difficult to predict and their costs difficult to forecast. Therefore, detailed claims for self-insurance allowances or requests for formal pass-through arrangements are a natural response to this uncertainty. As a regulator, the Commission must deal with these claims based on its obligations under the Code.

5.5.4 What will be the effect of the change?

In setting out a position on TSNPs' insurance, the Commission appreciates that TNSPs may differ in their approach to risk management. Varying tolerances for risk and a TNSP's strategic objectives may influence the scope of the preferred pass-through arrangements for example, or the degree of reliance upon self-insurance. It is expected that TNSPs will develop risk management plans that are tailored to their own circumstances.

Within this context, the Commission believes that TNSPs will have greater cost certainty if they are granted allowances for self-insurance and cost pass-through arrangements of the kind specified below. In particular, the ability to amend their revenue caps for the financial impact of pass-through events will help maintain their profitability, even viability. It may also be argued that this would have a positive effect on their credit ratings and the cost of acquiring funds.

Weighed against these considerations is the possibility that customers may be exposed to higher charges as a result of the changes. The proposed pass-through arrangements, in particular, act to transfer risk onto customers. The Commission has considered these implications carefully and believes that the guidelines below represent the balancing of TNSP and consumer interests.

5.5.5 The Commission's preferred position

Overall, the Commission believes that the introduction of these new categories of insurance is in keeping with the principles and objectives of the Code. As mentioned above, the allowance for the difference types of insurance represents an appropriate balance between the interests of the various stakeholders. The scheme would also better enable TNSPs to earn a fair return on their network assets without undue uncertainty caused by inadequate insurance coverage. The insurance arrangements proposed would be covered by the Commission's incentive regulation approach which would ensure that TNSPs had incentives to pursue ongoing efficiencies as part of their operations.

The Commission's preferred position

The Commission supports cost pass-throughs in limited circumstances. The Commission considers that it is important that the three approaches to risk management: taking out insurance with external providers; self-insuring for certain other risks; or agreeing pass-through rules to pass the cost of designated events on to customers, are adequately scoped and defined to ensure there is no overlap between them. Guidelines for dealing with these matters have been included in the Commission's GasNet and SPI PowerNet revenue cap decisions issued in 2002.

5.5.6 Guidelines for self-insurance and cost pass-throughs

Crucial to the efficient working of a regulatory regime that includes allowances for self-insurance and cost pass-throughs are clear guidelines for insurance events that would fall within each category.

Following is a more detailed description of self-insurance and pass-through arrangements.

Self-insurance guidelines

The high cost and restricted availability of some external insurance cover commonly leads businesses to consider self-insurance for certain categories of risk. By self-insuring, a business may save on the cost elements relating to administration and the profit margin that is built into external premiums charged.

Granting the same allowance for an insurance item, whether it is externally insured or self-insured, would provide the same incentive to the TNSP to control its costs.

However, this approach raises issues regarding implementation, such as the necessity of an actuarial review of the TNSP's insurance arrangements to establish the value of all risks that it faces. There may also be a view that the Commission is becoming involved in the micro-management of the business. The Commission will consider this matter further to determine the regulatory necessity of such an approach.

After examining the merits of self-insurance on efficiency grounds, the Commission has determined that the following matters must be established prior to considering a self-insurance application:

- confirmation of the board resolution to self-insure
- a report from an appropriately qualified insurance consultant that verifies the calculation of risks and corresponding insurance premiums
- relevant self-insurance details that unequivocally set out the categories of risk for which the company has resolved to assume self-insurance. This would need to clearly establish what the insured events and exclusions are, so as to avoid any future debate as to whether or not an event was a self insured one, and form the basis for actuarial assessment noted above
- a regulated entity's resolution to self-insure would also be expected to explicitly acknowledge the assumed risks of self-insuring (i.e. in the event of future expenditure required as a result of an insurance event such costs would not be recoverable under the regulatory framework as the relevant premiums would have already been compensated for within the operating and maintenance element of the allowed MAR and funded by users, eg if a 1 in a 100 year event occurs in year 1 then the business will need to have the financial ability to restore assets out of its own resources).

Board resolution and corporate governance requirements are fundamental issues. The risk management strategy of an entity and approaches to events that could affect the overall risk profile of the entity are matters for Board consideration. This is important because it may require parent entity/shareholder support to self-insure and/or affect debt covenant requirements of lenders.

Exclusion of certain items from the self-insurance allowance

The Commission considers that certain expenditure should not be compensated in self-insurance claims:

- self-insurance claims with respect to the departure of key persons and the resultant business interruption and costs. The Commission would expect that a prudent business would ensure that the skill base of its staff is sufficiently broad to accommodate some unexpected staff movements. It considers this is a risk faced by all businesses. It is also unlikely that there would be a significant disruption to a TNSP's revenue flows.

- an allowance for Employment Practices self-insurance. All businesses must comply with the relevant legislation covering such areas as harassment, unlawful discrimination and breaches of privacy

- regarding an allowance for deductibles in current insurance policies held by a TNSP, the Commission is of the view that it is more appropriate that actual expenditures should be included in the pass-through mechanism as an Insurance Event, rather than as an allowance in the cash flows. This is to ensure sufficient allowance is made for this item.

Self- insurance Guidelines

The Commission would like interested parties to comment on the self-insurance guidelines, taking into account the following matters:

- Should the TNSP's entire insurance arrangements, both external and self-insured, be the subject of actuarial review in setting a revenue cap?

- Do the guidelines provide the correct incentives to achieve efficient costs?

- Are the risks the TNSP faces adequately addressed by the guidelines?

- Should the list of excluded insurance items be varied and items covered under another area?

Pass-through guidelines

Cost pass-throughs provide a mechanism for dealing costs that are outside the control of the TNSP. As an alternative to receiving an allowance in its cash flows, a TNSP may transfer the financial impact of the event to consumers. It is envisaged that the range of potential pass-through events will be limited.

The Commission considers that a pass-through event must have the following characteristics:

- the event should be identified in advance with its scope precisely defined – this enables the following tests to be applied and is considered necessary for good, transparent regulation. A high degree of certainty is provided where the Commission and the TNSP agree up front on the events to be covered by pass-through arrangements
- the event must be beyond the control of the TNSP
- the financial impact of the event must be material
- the event affects the TNSP, and not the market generally – systematic or market risk should be addressed in the WACC parameters
- the financial impact of the event is better borne by parties other than the TNSP. This will only be appropriate where the TNSP cannot reasonably be expected to bear the risk itself, for example, in the case of uncontrollable events that may otherwise affect the commercial viability of the business. and
- by allowing a cost pass-through for the specified event, Code objectives and principles are fulfilled, for example, by providing a revenue requirement that has regard for the on-going commercial viability of the TNSP.

Operation of the pass-through mechanism

The Commission considers the following matters are important features of an efficient and equitable pass-through mechanism:

- the Commission reserves the right to initiate pass-through reviews at its discretion
- the pass-through mechanism should accommodate both positive and negative amounts in the interests of both TNSPs and customers
- a 40 business day assessment period to allow full assessment of pass-through event applications, including public consultation where appropriate, to be undertaken by the Commission. The Commission, at its discretion, may also extend this period to adequately assess pass-through proposals
- the provision by the TNSP of detailed documentary evidence in support of any pass-through application. Sufficient detailed information must be provided which substantiates that the aggregate costs facing the TNSP have increased or decreased as a consequence of the claimed pass-through event. Wherever possible, this information should also be provided in the public domain
- a TNSP must annually (at least 50 business days prior to the start of the financial year) provide the Commission with a copy of insurance premium invoices, irrespective of whether a pass-through event application has been submitted in that year.

The particular pass-through events that may be the subject of these arrangements is a matter for agreement between the Commission and the TNSP. However, all pass-through events must satisfy the tests detailed above.

Regarding the basic operation of the pass-through mechanism itself, the Commission will apply a common approach to all TNSPs.

Pass-through Guidelines

The Commission would like interested parties to comment on the pass-through guidelines, taking into account the following matters:

- Has the appropriate balance been achieved between the interests of TNSPs and customers?
- Should currently unidentified events be allowed for in the guidelines?
- Considered together with the external and self-insurance arrangements detailed above, have the TNSPs' overall risk management requirements been adequately addressed?

6 Incentive Regulation

6.1 What is the issue?

The Commission believes that the costs incurred by a regulated firm in the provision of a set of regulated services is, at least partly, within the control of the management of the regulated firm. Hence the owners of the regulated firm can be induced to exert effort towards reducing those costs through an appropriate system of financial rewards. The financial rewards to a regulated firm are usually in the form of higher allowed profits. Many regulators therefore seek to set up a mechanism which rewards the regulated firm with higher profits when the firm manages to lower its costs. These issues and other issues are discussed in more detail in Attachment B of the discussion paper.

An incentive mechanism is a rule which specifies how the regulated prices or revenues of the regulated firm depend on the cost out-turns of the regulated firm in past periods and/or on any external measures of the firm's costs.

For a given incentive mechanism, the stronger the incentives for cost-reducing effort created by the mechanism, the stronger the power of the incentive mechanism. The power of an incentive mechanism depends on the responsiveness of the present value of future prices/revenues to changes in the current cost out-turn. Therefore, the power of an incentive mechanism depends on the following factors:

(a) The extent to which the future prices/revenues depend on exogenous versus endogenous measures of cost; and

(b) The extent to which future prices/revenues depend on earlier versus more recent cost out-turns (i.e., the extent of the lag before cost changes are reflected in regulated price/revenues – this depends, in turn, on the length of the regulatory period).

An incentive mechanism is low-powered if future prices/revenues are closely related to recent cost out-turns of the regulated firm and is high-powered if future prices/revenues depend primarily on the costs of other firms.

6.1.2 The fundamental trade-off

Since low-powered incentive schemes yield relatively weak incentives for cost-reducing effort, regulators must rely on other mechanisms such as audits and detailed expenditure reviews to ensure a reasonable degree of cost discipline on the regulated firms. High-powered schemes, to the extent that they lead to strong incentives for cost-reducing effort, can reduce or eliminate the need for close scrutiny of the expenditure decisions of the regulated firm.

Higher-powered incentive schemes, however, risk unsustainable departures of prices/revenues from costs. For example, if the incentive mechanism allows outcomes in which the regulated prices/revenues are significantly above costs it may be impossible to prevent some form of political or regulatory intervention to bring prices more closely into line with observed cost out-turns.[19] No matter how high the power of an incentive scheme appears on the surface, a regulatory mechanism which threatens substantial departures of regulated prices from observed costs may not be credible.

Another problem with high-powered incentive schemes is that, since regulated firms can usually cut costs by cutting quality, higher-powered incentive schemes place greater pressure on regulatory mechanisms designed to maintain service quality. If maintaining service quality through regulatory mechanisms is difficult and imperfect, overall welfare may be improved by moderating the power of the incentive scheme.

A final drawback of high-powered incentive schemes is that they shift the risk of cost fluctuations from consumers to the regulated firm. To the extent that this risk is systematic, investors will need to be compensated for this risk in the form of a higher cost of capital. This higher cost of capital may offset or eliminate some of the gains from greater incentives for cost-reducing effort.

6.1.3 Issues raised by the approach set out in the Draft Regulatory Principles

The concept of the carryover

In the electricity industry in Australia, the standard approach is to use a five-year regulatory period. At the beginning of each regulatory period, the regulator must specify the path of prices or revenues over the next five years[20]. The currently emerging practice is to set the regulated prices in each period as the sum of two components – (a) the underlying cost benchmarks; and (b) a carryover of any efficiency gains or losses from the previous period (the difference between the cost out-turn and the cost benchmarks in the previous period).

There seems to be a common misunderstanding that the incentive properties of a particular mechanism depend on the carryover component alone. Since the properties of an incentive mechanism depend on the responsiveness of future prices or revenues to current cost-reducing effort, and since the prices are the sum of both the cost benchmarks and carryover components, the properties of an incentive scheme therefore depend on how *both* the cost benchmarks and the carryover are set.

It is therefore not possible to assess the properties of an incentive scheme without a clear specification of the mechanism for setting both the carryover and the cost benchmarks. Although some regulators have set out a particular mechanism by which the carryover component will be set[21], there remains significant uncertainty about precisely how the underlying cost benchmarks are determined.

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[19] This might arise either because the regulator fears that its own performance will be negatively assessed as a result of the apparently high profits of the regulated firm or simply because public pressure on the political system demands action to reduce “excess” profits.

[20] Or, if not the actual prices or revenues, a formula that will be used to calculate the prices or revenues on the basis of information which will become available later.

[21] Such as the “Rolling carry-over mechanism” proposed by ESCOSA and ORG.

This is also true for the DRP. The DRP specifies in some detail the nature of the carryover (glide path) component but not the role of past costs in setting the cost benchmarks.[22] At present, the cost benchmarks are determined by a process which involves inviting the regulated firm to provide estimates of its future costs for the next regulatory period and then seeking the opinion of external consultants on the appropriateness of those submitted costs. To the extent that the external consultants act as a check on the announced costs of the regulated firms, the question arises as to how those consultants arrive at their estimate of the appropriate level of costs.

To the extent that the scrutiny of the external consultants acts as a control on the costs of the regulated firms, the precise manner in which the consultants determine the appropriate level of cost is of primary importance for assessing the power of the incentive scheme set out in the DRP. To the extent that this process is uncertain or unspecified, the power of the incentives for cost savings will be indeterminate (and possibly varying over time).

Furthermore, it seems likely that any attempt to clarify the process by which consultants approve the cost estimates of the regulated firm will inevitably involve restricting the discretion of these consultants and, to an extent, replacing this discretionary process with a more mechanistic process.

Past cost information

The Commission invites comment on the following issues:

Should the Commission seek to clarify how past cost information will be taken into account when setting the cost benchmarks? This clarification might imply a more mechanistic approach to the setting of future revenues (such as a rule that future revenue is simply set equal to the average of past actual costs). Do you consider that a more mechanistic approach would be desirable if it clarifies the incentive properties of the regime? Is a mechanistic approach feasible?

Changing incentives for cost efficiencies over time

One particular problem which may arise when the regulator uses a fixed-length regulatory period is that the regulator, when setting the regulated prices for the forthcoming regulatory period, may place particular emphasis on the cost out-turn in just one year of the previous regulatory period. This year is usually the last year of the previous regulatory period for which data is available.[23] But if the future regulated prices depend only on the cost out-turn in that one year, the regulated prices are independent of the cost out-turns in other years. As a result, the regulated firm has

22 The DRP explains that "for reasons of simplicity the glide path will be a simple straight line phase out of efficiency gains. That is, for a regulatory period of five years, efficiency gains beyond the X factor would reduce at a rate of 20 per cent per year. Thus, the TNSP will keep 100 per cent of excess efficiency gains for the first year of the next regulatory period, 80 per cent of the excess efficiency gains for the second year, and so on, until all of the excess efficiency gains are phased out by the end of the regulatory period."

23 The penultimate year of the regulatory period is often the most recent year for which data is available.

high-powered incentives for cost reducing effort in years other than the year used by the regulator and (since that years costs affect prices for the entire forthcoming regulatory period) reduced (or even negative) incentives for cost reducing effort in that year.

Intuitively it is clear that this problem arises from the practice of setting the regulated prices on the basis of the cost out-turn in a single year. If this problem is to be eliminated, therefore, the regulated prices must depend, in some way, on *all* of the cost out-turns in the previous regulatory period (e.g., perhaps as some form of average of the past cost out-turns).

Incentives for capex efficiencies over time

The power of the incentives for cost reducing effort on capex depends on the responsiveness of the RAB to the actual capex of the regulated firm. If the RAB is adjusted ex post by an amount equal to the actual capital costs incurred by the regulated firm, the regulated firm will have little incentive to economise on capex. Conversely, if the adjustment to the RAB is independent of the actual capex costs incurred by the regulated firm, the firm will have very strong incentives to reduce its capex to the minimum.

The capex out-turn today may affect the RAB in the future in two ways: the first relates to the direct impact of a project's cost out-turn on the RAB allowed for that project; the second relates to the effect of a project's cost out-turn on the RAB target for similar projects in the future. (The tendency for past performance to influence performance targets set in the future is known as the ratchet effect). But capex projects differ in the extent to which the cost out-turn of a project today will affect future expectations. Projects which are one-off or unique may provide very little insight into the likely cost out-turn of other projects in the future. On the other hand, capex projects which are on-going or repetitive may be very informative as the likely cost of similar projects in the future. Therefore the power of the incentive mechanism may vary across capex projects.

Incentives for substitution between capex and opex

It appears to be generally accepted that regulated firms can substitute between opex and capex. This might arise, for example, if the maintenance costs of an asset increase with the life of the asset. In this context, bringing forward upgrades to the capital stock increases capex but reduces maintenance expenses and therefore opex costs. Conversely, by deferring asset replacement (and thereby increasing the maintenance expenses) a firm may be able to increase opex and reduce capex.[24]

An incentive mechanism which gives rise to different power of incentives for cost reducing effort for opex and capex creates incentives for the regulated firm to substitute between these two components of cost. For example, if there are high-powered incentives on opex and low-powered incentives on capex, a firm has a strong incentive to substitute capex for opex – any increase in capex has little negative effect

24 EEE Ltd (2002, 71) note: "There are recognised trade-offs between capital and operating costs; for example more regular inspections and partial replacements can make overhead lines last longer before full replacement".

on its profit while any decrease in opex has a strong positive effect on its profit. Conversely, a firm facing high-powered incentives for capex efficiencies and low-powered incentives for opex efficiencies has a strong incentive to reduce capex and increase opex.

Ideally, the regulated firm would have an incentive to minimise its total costs. A capex project which has a life of, say, ten years, will have an effect on opex for each of the next ten years. A capex project lowers total cost if and only if the capex increase is smaller than the present value of the opex cost savings over the life of the project. Alternatively, a capex project lowers total cost if and only if the NPV of the project is positive at the margin.

In other words, the incentives for cost reducing effort on capex and opex are balanced if the incentive mechanism is such that the change in profits of the regulated firm after carrying out a capex project is proportional to the NPV of the capex project at the margin.

Without further information on the power of the opex incentives under the present regime, it is impossible to make a definite statement on the relative power of opex and capex incentives. At this stage, it would seem that if the relative power of the incentives for capex and opex were, in fact, roughly equal this would be purely fortuitous.

Incentives for capex and opex savings

The Commission invites comment on the following issues:

To what extent does the current approach of the Commission suffer from some of the problems mentioned? In particular, do regulated entities have an incentive to make their costs appear higher towards the end of the regulatory period? Does the current regime provide incentives for cost efficiencies in new investments (i.e., in capex)? Is it possible to assess the relative power of the incentives for capex and opex efficiencies under the current regime? If so, are firms likely to put more effort into capex or opex savings? Is there any evidence of capex/opex substitution under the current regime?

6.2 Why change?

6.2.1 The Commission's Preferred Position

The current review of the draft Statement of Regulatory Principles is an opportunity for the Commission to determine if it wishes to clarify the current arrangements (so as to enable a better understanding of the incentive properties of the current regime) and, if so, to choose a rule or mechanism which specifies more precisely how past information on costs will be used to determine regulated prices.

In assessing the alternatives, the Commission must take into account the objectives set out in the Code. The Code specifies that the regulatory regime chosen by the Commission must seek to achieve: an incentive based regulatory regime which (1) provides an equitable allocation between Transmission Network Users and Transmission Network Owners … of efficiency gains reasonably expected by the ACCC to be achievable… and (2) provides for … a sustainable commercial revenue stream which includes a fair and reasonable rate of return … on efficient investment given efficient operating and maintenance practices.[25] In addition, the regulatory regime must seek to achieve an efficient and cost-effective regulatory environment and prevention of monopoly rent extraction by Transmission Network Owners.[26]

<u>The Commission's preferred position</u>

The Commission's preferred position is to adopt an incentive mechanism that creates constant incentives for efficiency over time.

6.2.2 What criteria should the Commission use?

Given these objectives, if the Commission were to clarify the incentive properties of its regulation by specifying a more mechanistic incentive mechanism, what criteria should that incentive mechanism satisfy?

In the light of the problems identified in the first section and the objectives set out above, we propose that the Commission should choose an incentive mechanism which satisfies the following criteria:

(1) The incentive mechanism *should lead to incentives for cost-reducing effort on both opex and capex which are constant over time*;[27]

(2) The incentive mechanism *should give rise to roughly equal incentives for cost-reducing effort on operating expenditure and on capital (i.e., investment) expenditure*; and

(3) Provided the incentive mechanism satisfies the two criteria above, is sustainable, and ensures adequate incentives for maintaining service quality the incentive mechanism *should yield the highest power of incentives for cost reduction*.

In other words, the regulated firm should have no greater incentive to exert effort to reduce expected costs in the current period whether at the beginning or at the end of the regulatory period; no greater incentive to exert effort to reduce capital costs relative to operating costs; and no incentive to shift costs across short time periods by, for example, accelerating or deferring depreciation. Subject to these conditions (and other regulatory objectives) the Commission should choose an incentive mechanism of the highest possible power.

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25 NEC 6.2.2. (b)

26 NEC 6.2.2. (a) and (c).

27 The South Australian regulator is explicitly required to choose an incentive mechanism which leads to constant incentives for efficiency. Clause 7.2(h) of the Electricity Pricing Order requires that ESCOSA must have regard to "the need to offer ETSA Utilities a continuous incentive (equal in each year of the regulatory period) to improve efficiency in operations, capital expenditure, the utilisation of existing capital assets and the acquisition of prescribed transmission service".

Criteria for incentive mechanism

The Commission invites comment on the following issues:

If the Commission were to specify an incentive mechanism in the statement of regulatory principles, what criteria should that incentive mechanism satisfy? How important is it that the power of incentives be constant over time? How significant are the inefficiencies that might result from varying incentives for efficiency? Should this objective be traded off against other objectives?

How important is it that the incentives for capex and opex efficiencies be roughly equal? Should this objective be traded off against other objectives?

Should other criteria be added?

6.2.3 Incentive mechanisms which meet the Commission's criteria

Constant incentives for opex efficiencies

Assume that the Commission has examined the past opex cost out-turns and has fully and correctly accounted for differences in cost due to changes in factors (such as input prices) which are outside the control of the regulated firm. The remaining differences in opex costs are, in principle, entirely due to differences in the level of cost-reducing effort by the regulated firm.

It seems that an incentive mechanism provides constant incentives for opex cost efficiencies if the endogenous component of the regulated prices (that part which is dependent on the observed cost out-turns in the past) is such that the present value of the regulated prices over the next regulatory period is a function of the present value of the observed costs in the previous regulatory period (see Attachment B of the discussion paper).

In other words, if the cost out-turns in the previous regulatory period are C_1, C_2, C_3, C_4, C_5, an incentive mechanism produces constant incentives for temporary cost reductions over time if the present value of the regulated prices over the next regulatory period is a function of $\sum_{i=1}^{5} \frac{C_i}{(1+r)^i}$.

This result holds, for example, for the carryover mechanism known as the Rolling Carry-Over Mechanism provided the cost benchmarks are set equal to the cost out-turn in the last year of the previous regulatory period (see Attachment B of the discussion paper).

But this is not the only incentive mechanism which has this property. In fact, as already emphasised, any incentive mechanism for which the endogenous component is a function of the present discounted value of the observed costs in the previous regulatory period will have the property that the incentives for temporary cost efficiencies are constant over time. In particular, it is possible to derive a form of the glide path or the moving average carryover which, under certain conditions, lead to constant incentives for efficiency over time.

Constant incentives for opex efficiencies

The Commission invites comments on the following issues:

Does the proposal (that the presence value of regulated prices should be a function of the present value of cost out-turns in the previous regulatory period) achieve the objective of constant incentives for efficiency over time? What problems do you foresee with this approach?

Does the proposed approach still apply if the Commission cannot fully and correctly distinguish between controllable and uncontrollable costs? If not, how should the proposal be changed?

Constant incentives for capex

Should the Commission be concerned about ensuring constant incentives for capex efficiencies over the regulatory period? Capex, unlike opex, does not consist of repeated ongoing expenditure for a similar set of services. Rather, capex varies from year to year and period to period depending on the nature of the capex projects undertaken. It is not clear that past levels of capex provide much useful information about future levels of capex. Hence, it is not clear that future "benchmark" levels of capex are influenced much by capex out turns today. As a result it is not clear that there is a declining incentive for capex efficiencies over the regulatory period, so there is no need to think about incentive mechanisms which yield constant incentives for capex efficiencies over time.

6.2.3 Incentives for substitution of capex and opex

An incentive mechanism yields balanced incentives for capex and opex cost efficiencies if the responsiveness of the present value of regulated prices to the present value of the opex cost out-turn is the same as the responsiveness of the RAB to the capex cost out-turn. See Attachment B.

Earlier we observed that the process by which the cost benchmarks are set is something of a black box. As a result, it is unclear how responsive future prices/revenues are to changes in the opex out-turn today. The same problem arises with capex. It is currently unclear how the RAB will be adjusted in the light of the capex cost out-turns (and, repeatedly, how capex cost out-turns today affect estimates of future forecast capex costs).

There is also a link here with the regulatory test. The regulatory test is a test of the prudency of capital expenditure projects which expand or enhance the electricity transmission network. The regulatory test involves a cost-benefit analysis of the project against a selection of alternative projects. The regulatory test requires that the cost of a particular project be accurately forecast in advance. For the purposes of this paper, this raises two issues:

(a) First, how are those forecast costs determined? Is it on the basis of the cost of similar projects in the past? Or are past projects irrelevant?

(b) Second, if a project passes the regulatory test, is the Commission obliged to allow the TNSP to roll in to the asset base the full forecast cost of the project? Or, can the Commission take into account the capital cost out-turn when deciding how much to roll into the RAB? Or can the Commission use some combination of the forecast cost and the actual cost out-turn?

Incentives for substitution between capex and opex

The Commission invites comments on the following issues: Is it feasible to enhance the incentives for capex efficiency savings through an incentive mechanism on capex? Such a mechanism would require that the amount rolled into the RAB was largely independent of the capex cost out-turn. How would this amount be determined? Is it possible to ensure that the incentives for capex efficiencies are constant over time? Should the Commission be concerned about the incentive on regulated entities to substitute between capex and opex? Does the proposed mechanism achieve balanced incentives for capex and opex efficiencies? How much flexibility does a regulated TNSP to substitute between capex and opex?

6.2.4 Enhancing the power of incentives

The third criterion set out above was that, subject to the other objectives being met, the Commission should seek an incentive mechanism which yields the highest possible power.

As noted earlier, increasing the power of an incentive scheme will likely involve a trade-off with other objectives. For example, increasing the power of an incentive scheme may lead to an inefficient reduction in service quality or an inefficient substitution of capex for opex. As already noted, a high powered incentive scheme may give rise to unacceptable deviations of regulated prices from observed costs. For all these reasons, the incentive mechanism which yields the highest possible power consistent with the other objectives may not be a very high-powered incentive mechanism at all.

Nevertheless, it is not at present possible to state that the Commission is currently using an incentive mechanism with the highest possible power consistent with the other objectives. It is worth exploring, therefore, how the Commission might seek to enhance the power of the regulatory regime while preserving the other objectives.

As has been emphasised several times, the power of an incentive scheme depends not just on how regulated prices are related to past cost out-turns (the endogenous component) but also on how regulated prices are related to factors outside the control of the regulated firm (exogenous factors). The most straightforward way by which the Commission can enhance the power of its incentive mechanism is to place greater weight on exogenous measurements of costs. This issue is taken up the next chapter on benchmarking and discussed in more detail in Attachment B.

Note that if the Commission chose to move to exclusive reliance on benchmarking (i.e., if the regulated prices depended entirely on exogenous cost measures) there would be no need to consider efficiency carry-over mechanisms and other incentive mechanisms which ensure constant incentives for efficiency. The problems with incentive mechanisms discussed in this chapter (such as the problem of ensuring constant incentives for efficiency) are related to how the regulated prices should depend on endogenous measures of cost – obviously, the greater the reliance on benchmarking the less the need to be concerned with these problems.

7 Benchmarking

The power of a regulatory mechanism can be increased by increasing the extent to which regulated prices or revenues depend on the exogenous measures of cost. (see Attachment B for more detailed discussion.)

7.1 Cost Drivers

Just as endogenous measures of cost derive primarily from observations of the regulated firm itself, exogenous measures of cost are derived from observations of the cost out-turns of *other* comparable firms perhaps over several time periods.

A substantial component of the differences in cost observations between firms are due to legitimate or "uncontrollable" differences in factors which affect the level of costs incurred by the firms, such as:

- the level of output that the different firms produce,
- differences in the prices they must pay for inputs and
- differences in the business conditions to which each firm is exposed.

For example, the costs of electricity transmission or distribution businesses might differ due to differences in:

- The *nature of the services* provided by each firm (for example, a transmission network designed to provide reliability services might appear to have quite different average costs than an otherwise identical network designed to provide transportation services);
- The *range of services* provided by the firm (a distribution business might appear as higher average cost if it is required to provide additional services, such as street lighting or heating, which are not provided by the comparator firms);
- The *volume of services* provided (a transmission or distribution business carrying smaller volumes might appear as higher average cost if there are economies of scale);
- The *quality of services* provided (a firm which offers *n-2* reliability might appear as higher average cost than a firm which offers *n-1* reliability);
- The *price of inputs* (firms in rural areas might have to pay more to attract particular labour skills);
- *Governmental regulations* (companies which must control noise emissions may face higher average costs than those which do not);

- The *number, density, load factor and size distribution of the customers they serve* (companies which have a higher load factor or customer density may have lower average cost than those companies which do not);

- *Environmental factors* (companies in regions with high temperatures or a greater propensity to electrical storms may have to take more precautions than those in more temperate areas);

- The *age and quality of the capital stock*;

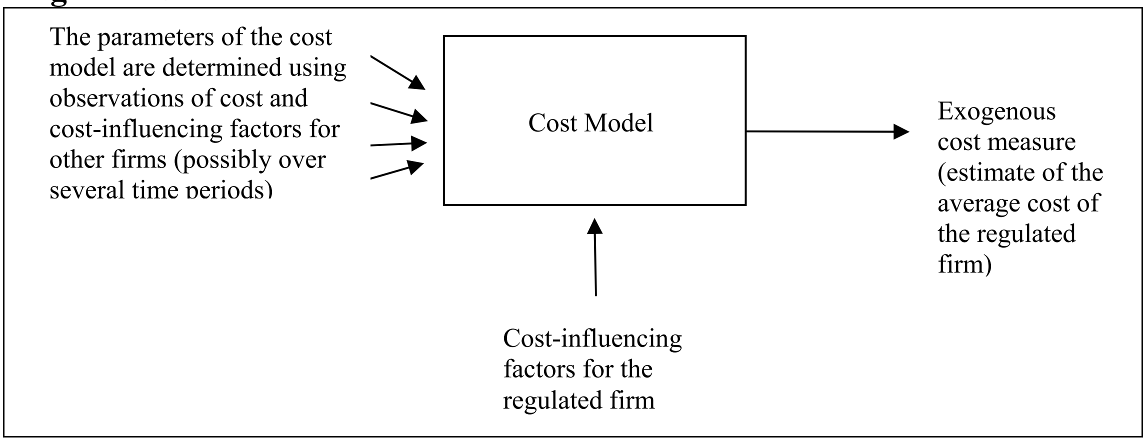
Just as important, the total cost of a regulated firm consists of both costs which can be attributed to a single time period (opex) and the costs of sunk long-lived assets which cannot be unambiguously attributed to a single time period (capex). The methodology by which the costs of sunk assets are amortized will have a substantial impact on the resulting cost observations. The handling of capital costs is, therefore, yet another factor which can have a substantial influence on observed cost differences across firms.

7.2 Cost models

Having collected information on cost out-turns and cost-influencing factors of other comparable firms, the regulator must use that information to obtain an exogenous cost estimate for the regulated firm. This is done by estimating a cost model.

The diagram below illustrates the basic structure of a cost model – the model takes as inputs information on costs and cost-influencing factors for a number of other firms. This information is combined with information on cost-influencing factors for the regulated firm to come up with the exogenous cost measure (which, in this case, is a measure of the average cost of a firm facing the same cost drivers as the regulated firm).

Figure 1 Cost Model



One common approach is to estimate the cost function using standard statistical techniques. Under this approach the basic structure of cost function is specified as a function of a number of parameters.[28] These parameters are then chosen in such a way that the cost model is the best fit for the available data.

The use of statistical techniques allows the modeller to come up with an estimate of the accuracy of the resulting estimates. Kaufmann et al (2000) observe that:

> An important advantage of the econometric approach to benchmarking is that results can assess the *precision* of such point predictions. Precision is greater as the variance of the prediction error declines. The formula for our estimate prediction error shows that, generally speaking, the precision of the cost model will increase as:

- The size of the sample increases;
- The number of business condition variables [called here cost influencing factors] required in the model declines;
- The business conditions of sample companies become more heterogeneous;
- The business conditions of the company in question become closer to those of the typical firm in the sample; and
- The model is more successful in predicting the costs of the sampled companies.[29]

There are a number of other approaches to estimating cost models. Another statistical technique is stochastic frontier analysis which seeks to estimate not the average costs of a firm but rather the cost function of the hypothetical efficient frontier. There are also non-statistical techniques of which the best-known is data envelope analysis.

Cost Model

The Commission invites comment on the following issues:

Should the Commission place greater reliance on using benchmarking techniques to model costs? What do you see as the greatest risks of moving in this direction?

What are the primary cost drivers of electricity transmission companies? Is it possible to develop a reasonably reliable cost model for Australian electricity transmission companies?

7.3 How should the output of cost models be used?

It is likely that the regulator in using a cost model to determine regulated revenues, cannot be certain that it has correctly accounted for all inter-firm differences in cost. No matter how sophisticated the model chosen by the regulator, since the other comparator firms inevitably all face different circumstances to the regulated firm,

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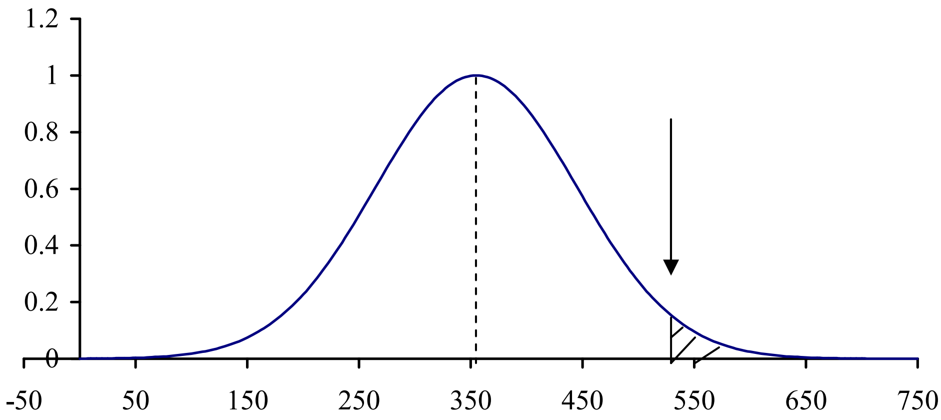
28 For example, the cost function is often assumed to take a Cobb-Douglas form.

29 Kaufmann et al (2000), page 9

there is always a chance that the model does not fully account for all inter-firm differences in cost. In this case, the regulator cannot set the regulated revenue directly on the basis of the observed exogenous cost. Doing so runs the risk that the regulated firm will systematically under-compensated.[30]

A primary requirement of any regulatory regime is the requirement that the regulated firm be adequately compensated for prudently-incurred investment. Therefore, the regulator *must* set the regulated revenue in such a way that there is at least a very high probability that the regulated firm will be properly compensated even if the cost model has systematically underestimated its true costs. Where a cost model is used, the regulator can use statistical analysis of the data to establish confidence intervals with respect to the estimated revenue requirement.

For example, in the diagram below, the cost model has yielded an estimate of the average cost of $355 million. But, taking into account the likely error in the forecast, if the regulator is to be 99% sure that the regulated revenue exceeds the firm's true costs, the regulated revenue must be set at $540 million.



Thus the appropriate level of the regulated revenue will depend on the statistical error of the cost model (i.e., the residual or unexplained component of observed costs). The higher this statistical error, the higher the regulated revenue will need to be to ensure that the revenue exceeds the true cost with a high probability.

Of course, this argument implies that the regulated revenue will on average over-estimate the true costs of the regulated firm. But this should be no surprise. Economic theory demonstrates that over-compensation of a regulated firm is an inevitable consequence of the regulator's lack of information about cost. This over-compensation is an additional rent earned by the firm as a result of its information advantage and is called information rent. The following quote from Laffont and Tirole (2000) explains this principle:

> In the presence of incomplete information about the firm's technology or opportunity cost … the government faces a trade-off between giving good

[30] There is also a risk that the regulated firm will be systematically overcompensated. This, also, could render the incentive mechanism is unsustainable.

incentives to the firm and capturing its potential rent. Recall that proper incentives for effort are created by a fixed-price contract (or more generally by a high-powered incentive scheme). But a contract that yields $1 to the firm each time the firm endogenously reduces its costs by $1 also gives it $1 whenever its cost is lower by $1 for exogenous reasons; that is, a firm is a residual claimant also for cost factors that are outside its control. This fact generates substantial rents. In contrast, a cost-plus contract (or, more generally, a low-powered incentive scheme), while providing poor incentives to keep cost down, is efficient at capturing the firm's potential rent. Indeed, the firm does not benefit when it is lucky and its cost is exogenously reduced by $1, since this cost is fully borne by the government.

To illustrate this adverse selection problem and the impact of the power of the incentive scheme, suppose that there is no moral hazard problem – that is, that the firm's cost is exogenously determined. This cost can be either 5 or 10. If the government is constrained to offering a fixed-price contract, and if the public good is socially sufficiently valuable so that the government must supply it, then the government has no choice but offering 10 to the firm. While this offer ensures that the firm is willing to produce the public good, it also leaves a rent equal to 5 if the firm has a low cost. In contrast, a cost-plus contract pays only what is needed to let the firm break even. [Assuming that low effort translates into an excess cost of 3] the realised cost is then, say, 8 or 13 … but the payment matches the cost.

We thus conclude that *there is a basic trade-off between incentives, which call for a high-powered incentive scheme, and rent extraction, which requires in the presence of adverse selection, low-powered incentives*.[31]

<u>The use of an output cost model</u>

The Commission invites comment on the following issues:

Supposing the Commission is able to develop a cost model for transmission companies, how should the Commission use the output of this model? Do you agree with the proposition that the Commission should set the regulated revenue equal to an amount which is sufficiently higher than the estimated costs so that the regulated company is highly likely to be adequately compensated? Is this overcompensation likely to be an important concern in practice?

7.4 Offering a menu of tariff options

Reliance on exogenous cost measures may result in unsustainable information rents accruing to the regulated firm. However, the regulator can still use exogenous cost measures as part of a suite of regulatory option offered to the regulated firm.

In particular, the regulator can ensure that the regulated firm does not go under-compensated by allowing the regulated firm the *option* of choosing a low-powered

[31] Laffont and Tirole (2000), page 40-41, emphasis in the original.

incentive scheme (such as rate of return regulation) if it wishes. Although there is some probability that the regulated firm will choose the low-powered incentive scheme and will have only weak incentives for cost-reducing effort, there is also some probability that the regulated firm will choose the high-powered incentive scheme and will therefore have strong incentives to increase its efficiency.

Thus if the true costs of the regulated firm were such that the firm would be under compensated by the regulated revenue based on the exogenous cost measure, the firm could choose the regulated revenue based on the endogenous costs, which yields a strong assurance of being adequately compensated. Alternatively, if the true costs of the regulated firm were such that the regulated revenue based on the exogenous cost measure would lead to over compensation of the firm; the firm take that option and, the economy would benefit from the stronger incentives for cost efficiency.

Further if the regulator is able to offer a third medium-power incentive, the regulated firm may choose this medium-powered tariff rather than just rate of return regulation.

In fact, economic theory shows that the theoretically optimal regulatory regime involves a (possibly large) menu of tariff options from which the regulated firm can choose. If the regulated firm happens to have a true cost which is significantly higher than the exogenous cost estimate the regulated firm will choose a low-powered incentive scheme. The lower the true cost of the regulated firm, the higher the power of the incentive scheme it will choose. Under the optimal regulatory regime, if the regulated firm happens to have the lowest possible true cost it will always choose the highest powered incentive scheme and will therefore choose the efficient level of cost-reducing effort.

Menu of options

The Commission invites comment on the following issues:

Should the Commission develop further the proposal to offer a menu of tariff options?

7.5 Benchmarking in practice

There have been a large number of studies of benchmarking in the electricity industry, (see Attachment B), mainly focused on benchmarking of electricity distribution companies. It appears that benchmarking of electricity transmission companies is more difficult, perhaps due to differences in the role played by electricity transmission in different countries.

At this stage it appears that even in the case of distribution companies (for which data for a large number of comparable firms overseas is available), obtaining a forecast with a precision (i.e., the ratio of the standard error to the cost estimate itself) less than 15% is unlikely. Further analysis is needed to determine the extent to which it is possible to develop an accurate cost model for TNSPs in Australia.

Throughout this chapter, the discussion has focused on the use of benchmarking as a tool to set the total regulated revenue for the firm. However it may be possible to use benchmarking as a tool to set some components of the total revenue such opex.

Inter-firm comparisons of opex may, at some level, provide useful insights, but there are difficulties with using benchmarking to set the opex component of total revenue. For example, to the extent that capex and opex can be substituted, differences in opex levels across different firms may be entirely due to differences in the capex/opex trade-off without reflecting differences in efficiency at all.

In the same way, inter-firm comparisons of capex programs and capex project cost out-turns may provide important and useful information, but it is difficult to see how benchmarking could be relied on systematically to set an allowed level of capex revenue. A firm which is adjusting to a different capex/opex trade-off might have a different level of capital spending without reflecting any differences in efficiency.

Applying benchmarking just to opex

The Commission invites comment on the following issues:

Should the Commission apply benchmarking to individual components of the total allowed revenue (such as operating expenditure)? In your view is benchmarking of opex alone feasible or sensible? What are the problems that are likely to arise? Is it possible to use benchmarking as a tool to assist in the scrutiny of capital expenditure plans?

The Commission's preferred position

The Commission's preferred position is to explore the scope for greater reliance on exogenous cost measures (often called "benchmarking") when setting the revenues of regulated TNSPs.

8 The Weighted Average Cost of Capital

8.1 What is the issue?

The Code states that in determining a TNSP's revenue cap, the Commission must have regard to the service provider's fair and reasonable WACC. The WACC for a firm is the weighted average of the costs of its equity and debt financing sources.

The WACC is a commonly used measure for determining a return on an asset base and its adoption, along with the building block approach, has been consistently applied by regulators in Australia. It can be determined and applied on an industry basis or it can be determined for each TNSP and benchmarked against other service providers/firms with similar risk profiles. The Code allows for the WACC to be determined on the basis of both an industry and individual TNSP.[32]

Electricity transmission is a highly capital intensive industry where the return on capital accounts for about half of the annual maximum allowable revenue. Small changes to the cost of capital can have a substantial impact on the total revenue requirement and ultimately on end-user prices. Hence, correctly assessing the return on capital is very important.

If the return is too low, the regulated network will be unable to recover the efficient and fair costs of service, thereby reducing its incentive to reinvest in the business. Conversely, if the return is too high, networks will have a strong incentive to overcapitalise (gold plate), thus creating inefficient investment and high cost to users.

8.2 How has the WACC been dealt with to date?

To establish an appropriate level of return on capital for the network owner, the Commission applies the building block approach which combines a benchmark rate of return with a regulatory asset value. The Commission adopts the cash flow modelling approach as specified in the Code and outlined in the DRP.[33] This approach extracts the parameters relating to business income tax from the WACC formula. In doing so, the Commission explicitly models the impact of tax and franking credits on the required post-tax distributions in the cash flows.

The remaining WACC formula, which has been termed the vanilla WACC, is merely the weighted average of the partially grossed-up return on equity and the pre-tax cost of debt:

$$WACC = r_e (E/V) + r_d (D/V)$$

where:

r_e = required rate of return on equity

r_d = cost of debt

32 National Electricity Code, clauses 6.2.2(b)(2) and 6.2.4(c)(4).

33 Proposed statement 6.3, ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues*, 27 May 1999, p. 84.

E = market value of equity

D = market value of debt

V = market value of equity plus debt.

8.3 The Commission's preferred position

The Commission's position is to maintain its current approach to estimating a fair and reasonable WACC applicable to TNSPs and considers it is the most appropriate method for determining the return on the asset base.

8.4 The Capital Asset Pricing Model

8.4.1 What is the issue?

The cost of equity capital is the expected return required to compensate investors for bearing the risk associated with investing in a firm's equity. The cost of equity is an ex-ante (ie. forward looking) concept, and determines the return expected by investors on their investment.

A common approach used to determine the cost of equity capital is to apply the Capital Asset Pricing Model (CAPM). The CAPM is a one-period partial equilibrium model of asset returns and can be used to determine the return on a stock over a given investment horizon.[34]

As illustrated in the following formula, CAPM yields the required average or expected return given the return on the market portfolio, the market's own volatility and the systematic risk of holding equity in the particular company:

$$r_e = r_f + \beta_e(r_m - r_f)$$

where:

r_f = the risk free rate of return

$(r_m - r_f)$ = the market risk premium (MRP), measured by the return of the market (r_m) as a whole less the risk free return

β_e = the systematic risk of the individual company's equity relative to the market.

8.4.2 How has the cost of equity been dealt with to date?

The cost of equity capital can be calculated using historical input data as a proxy for ex-ante returns due in part to the subjective nature of future estimates.

In evaluating a firm's cost of equity capital, it is usual regulatory and corporate financial practice to apply the CAPM. This is in part due to CAPM's relative

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[34] The Commission uses the Sharpe-Lintner version of the CAPM which, *inter alia*, requires the risk free rate of return.

simplicity in explaining the cross-section of stock returns by their sensitivity to returns on the market portfolio.

Although alternative models seem to suffer from ambiguity in empirical testing, problems with estimating parameters appear to be considerably less for CAPM than for other multi-factor models such as the Arbitrage Pricing Theory. These considerations do not favour alternatives to the CAPM and this is consistent with CAPM's dominance in practice. The Commission currently uses CAPM and maintains that it remains the most preferable of methods to estimate the cost of equity.

8.4.3 The Commission's preferred position

Whilst the Commission is aware of the alternatives to the CAPM and their strengths and weaknesses, at the present time the Commission prefers the continued use of CAPM to calculate the cost of equity.

8.5 Risk Free Rate

8.5.1 What is the issue?

The theoretical risk free rate (r_f) reflects the return on an investment that is free of risk and forms the foundation for both the cost of equity and the cost of debt. The market risk premium (MRP) is added to the r_f to ascertain r_m, whilst the debt margin is added to the r_f to determine the return on corporate debt.

In practice, yield to maturity on government bonds is used as a proxy for the r_f. Although there is inflation risk involved with holding government debt, the government may print money or raise taxes in order to service its debt repayments.[35]

8.5.2 How has the risk free rate been dealt with to date?

Term to maturity of r_f

Government bonds may be issued with virtually any time horizon. Governments have issued bonds with 5, 10, 30 year horizons and, in some cases, have issued bonds which never mature (known as perpetuities). In the case of Australia, the longest most traded government bond rate is the 10 year bond.

The arguments for using 5 or 10 year r_f rates can be separated into two broad areas. Using the 5 year government bond in determining the WACC would be commensurate with the length of the regulatory period for which revenue caps are usually set. Conversely, using the 10 year government bond would more closely match the life of the assets and therefore the investment horizon.

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35 The spread or difference between yields to maturity on government bonds of different maturities (the yield curve) is explained by theories of the term structure of interest rates. These include the Expectations Hypothesis, Liquidity Preference Hypothesis, Market Segmentation Hypothesis, and Preferred Habitat Hypothesis. (See Brailsford and Heaney, *Investments,* 1998).

Proponents for the use of the 5 year rate argue that a TSNP should not be rewarded for interest rate risk which is not being borne.[36] This increased allowance is inappropriate as it is deemed compensation for bearing interest rate risk for a period beyond the review term, when the TNSP does not face that risk due to the resetting of the output price to reflect interest rate changes.

Proponents of using the 10 year rate argue that if the planning period of the TNSP is longer than the regulatory period, the longer term rate will better reflect the investment horizon.[37] When funds are committed to investing in networks, they are typically long-term investments. Even when it is known that the allowed rates of return on the investment will be reset at regular intervals, the comfort of having those rates prescribed at the time of the investment is not apparent. Full compensation, should the investor choose to walk away from the investment, is also not an option.

Proponents of the 10 year rate argue that the use of the 5 year rate, matching the regulatory period, makes the unrealistic assumption that the regulated assets are sold and re-bought at the end of the regulatory period. They further contend that this assumption implies that the investment horizon is the regulatory period.

The Commission currently uses a government bond with the term that matches the regulatory period of each particular TNSP in setting their revenue caps.[38]

Length of period used in moving average of r_f

In determining a final figure for the r_f to apply to the WACC calculation, the most relevant figure to use is the on-the-day rate. This reflects the notion that the on-the-day rate fully reveals all the information available in the market.

However, using the on-the-day rate exposes the TNSP to day-to-day volatility in the r_f as new information is priced by the market. For this reason, an averaging methodology is used to smooth out this volatility.

8.5.3 Why change?

Term to maturity of r_f

The argument regarding which term to maturity to use as a proxy for the r_f comes down to a decision on the investment horizon of TNSP assets, and whether the regulatory period best defines the TNSP's investment horizon.

Professor Officer critiques the assumption that the assets are sold at the end of each regulatory period. This assumption forms the basis of Lally's[39] argument that the regulator should not reward the TNSP for inflation risk that is not borne. This directly

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36 Lally, *Determining the risk free rate for regulated companies,* 2002. (see also Davis (1998)).

37 Officer, *SPI PowerNet Revenue Application Appendix F*, 2002.

38 The five and a half year rate was used in recent electricity decisions including Powerlink, SPI PowerNet and ElectraNet. The ten year rate was used for Murray link for the preliminary decision. This is consistent with the Commission's approach in other industries.

39 Associate Professor Martin Lally is an academic staff member of The School of Economics and Finance, Victoria University of Wellington.

addresses the issue of the investment horizon, and which rate is the correct one, if one does indeed exist.

When a revenue cap is set, adjustments are made to the net cash flows on an annual basis to allow for unexpected changes in inflation. This would imply that the TNSP does not face inflation risk within the regulatory period. This suggests that it would be more appropriate to adopt as a r_f the rate of return on a one-year government bond.

The Commission engaged Professor Kevin Davis[40] to incorporate these arguments into a discussion of the appropriate bond rate to use for the risk free rate.[41] In his report, Davis puts forward that because long term interest rates will, on average, exceed short term interest rates for reasons other than expectations of future increases in interest rates, the use of the longer term interest rate as a proxy for the risk free rate will lead to higher regulatory cash flows than if the short term rate were used.

Davis demonstrates that the use of an interest rate with maturity equal to the regulatory period in deriving the required return for the regulated asset generates expected cash flows which are fairly priced in net present value terms. Furthermore, using a maturity which exceeds the regulatory period provides excess returns for the regulated asset if there is a positive term premium in the yield curve, unrelated to interest rate expectations.

Length of period used in moving average of r_f

The length of averaging period (between five to forty days) used in determining the r_f will affect the r_f actually used.

8.5.4 What will be the effect of the change?

As there is usually a positive spread between the 5 and 10 year bond rate, annual revenues would increase by approximately the amount of the spread if the 10 year bond is used. The spread has a historical average of 20-25 basis points, but would depend on market data prevailing at the time of the decision. Also, should a 10 year term be used, the cost of debt (see section 6) would be determined using market data associated with a 10 year term. At present, debt margins are calculated using market data from 5 year corporate bond yields, therefore moving to a 10 year rate would correspond to an increase in the cost of debt.

40 Professor Kevin Davis is Commonwealth Bank Group Chair of Finance, Department of Finance, The University of Melbourne.

41 Davis, *Report on Risk Free Interest Rate and Equity and Debt Beta Determination in the WACC*, Report for ACCC, May 2003.

8.5.5 The Commission's preferred position

Term to maturity of r_f

Consistent with its regulatory decisions, the Commission maintains that the use of a rate that matches the regulatory period does not reward additional interest rate risk which is not being borne. It should be noted that the Commission's preferred position may be subject to the Australian Competition Tribunal (Tribunal) findings in relation to GasNet's appeal against the Commission's 2002 access arrangement.

Length of period used in moving average of r_f

In previous revenue cap decisions, a 40 day or a 10 day moving average has been adopted. The Commission proposes the length of period (between five to forty days) used to calculate the moving average of the r_f should be left to the discretion of the TSNP when making its application. However, the TNSP will not be given the discretion to change the averaging period once this period has been determined in the application stage.

The Commission's preferred position

In addition, the Commission's preferred position is to adopt a government bond rate that matches the regulatory period as a proxy for the risk free rate.

Risk free rate

Comment is invited on:

- The appropriate term to maturity of the risk free rate; and
- Length of period used in calculating the moving average of the risk free rate.

8.6 Market risk premium

8.6.1 What is the issue?

The market portfolio represents the group of risky assets held by investors in equilibrium. The r_m is the expected return on the market portfolio. Individuals select an expected return and associated level of risk according to their own relative risk aversion.[42]

The MRP is the difference between r_m and r_f and is critical to the CAPM. It is the return, in addition to the r_f, that investors demand to hold the market portfolio of risky assets. The problem remains that expected returns are ex-ante and therefore not readily observable. To circumvent this problem, an ex-post measure such as the

42 This implies that the market portfolio is mean-variance efficient where risk and return are the only two moments of the distribution of returns required in pricing market risk. Individuals seek to maximise returns and minimise risk through diversification and therefore hold the market portfolio in equilibrium.

historical difference between r_m and r_f is used. This approach has appeal but is subject to the relevant period for taking an average.[43]

8.6.2 How has the MRP been dealt with to date?

Regulatory decisions in Australia have used a historical MRP (ex-post measure) of between 5-7 % per annum representing the long run average return on Australian stocks.[44] Decisions in the UK have used an historical MRP of 3.5 %.[45] The rationale for such differences is that there are segmented stock markets, and investors require a higher risk premium to invest in the Australian market.[46]

There is evidence that the MRP moves inversely with government interest rates suggesting that in times of low inflation and expected inflation (reflected by lower long term interest rates), the MRP is higher.[47]

Arguments for a lower MRP stem from the fact that the economy as a whole is much less risky than the stock market. Households typically receive income from wages and salaries and other sources that resemble aggregate returns, rather than simply returns on the stock market. Risk can be diversified away using household's other sources of income, thus a lower MRP would seem more plausible than experienced in the past.[48]

There is often comment made that historical estimates of the MRP have been calculated as some historical average of the actual market return over a long term risk free rate. Typically the risk free rate used is a 10 year government bond rate. Therefore, the assertion is made that if these estimates of the MRP are to be used in CAPM, consistency requires that a long term bond be used as the risk free rate. However, according to Davis, a number of arguments can be advanced against that position.[49] Further undermining this consistency rationale is the fact that in beta estimation, short term interest rates (ie. 90 day bank bills) are frequently used.

The Commission currently adopts a figure of 6 % per annum for the MRP, which reflects the long run historical return on the Australian stock market. This is consistent with a comprehensive study by Lally for the Commission, which recommended a MRP of 6 % as reasonable.[50]

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43 An alternative method is to use expected data from financial analysts to estimate the MRP. (See Harris and Marston*, Expectational estimates using analyst's forecasts, Financial Management*, 1992). See also Lally, *The Weighted Average Cost of Capital for electricity lines businesses,* Jan 2003.

44 Lally's study of the MRP in Australia.

45 OFGEM, *Review of Transco's price control from 2002*, Feb 2001.

46 For a discussion on US MRPs see *Research Roundtable – The Equity Premium* at http://papers.ssrn.com/paper.taf?abstract id=234713.

47 Harris and Ferston, *The Market Risk Premium*, 1999.

48 *Research Roundtable – The Equity Premium.*

49 Davis, *Report on Risk Free Interest Rate and Equity and Debt Beta Determination in the WACC*, Report for ACCC, May 2003.

50 Lally, *The Cost of Capital under Dividend Imputation*, June 2002, p.34.

8.6.3 The Commission's preferred position

The Commission considers no changes should be made to the current approach of estimating the MRP.

8.7 Beta

8.7.1 What is the issue?

The equity beta (β_e) is a measure of the sensitivity of returns to a particular stock with the return on the market portfolio (r_m). Under the CAPM, the β_e is used as a measure of the systematic risk of a particular stock relative to the market portfolio, and thus explains the cross section of returns to different stocks.

The value of an β_e is dependent on, *inter alia*, the amount of debt that a firm has, so that the higher the level of debt (or gearing), the higher the β_e tends to be. An β_e of more than one would imply that a firm has a higher level of systematic risk than the market average, and vice versa.

Related to the β_e is the asset beta (β_a) or un-levered beta. The β_e is simply a function of the β_a and debt beta (β_d). If a firm is financed entirely by equity (and no debt) the asset and equity betas will be identical. The β_d, which measures the systematic risk of debt, is a contentious parameter as it is less studied but there is a variety of suggested approaches to its estimation.

8.7.2 How has the equity beta been dealt with to date?

The Commission has generally computed an β_e of one for TNSPs. This figure is re-levered from an β_a of 0.4, using the assumed 60:40 gearing ratio, with a debt beta of zero. It should be noted that β_a is not directly observable and therefore must be derived from equity betas in the de-levering process. A similar approach employed is to consider a range of possible asset (and sometimes debt) beta estimates. The β_e is then selected from the resulting range as calculated through the Monkhouse de/re-levering formula, which is shown below:

$$\beta_e = \beta_a + (\beta_a - \beta_d) \{1 - [r_d/(1+r_d)](1-\gamma)T_e\} \; D/E$$

where:

γ	= the proportion of franking credits that can be used by shareholders to offset tax payable on other income
T_e	= the effective tax rate
D	= market value of debt
E	= market value of equity.

However, in electricity the de/re-levering process has only been used to justify a desired β_e rather than as a genuine method to obtain a benchmark β_e from a sample. In essence, this method was a type of benchmarking but without reference to actual market conditions as there were difficulties in obtaining credible market data.

The figure of 0.4 for the β_a, and the corresponding β_e of one often used was partly justified in recent decisions (including SPI PowerNet and ElectraNet) with reference to the 'Infrastructure and Utilities' industry average equity beta from early 2002. However, this sector classification is composed of many firms which have little in common with regulated utilities firms. From June 2002, the Australian Stock Exchange (ASX) re-defined the Australian market industry classifications in accordance with the Global Industry Classification System (GICS). The new 'Utilities' sector is a much closer match to the characteristics of regulated firms (although there are still a substantial number of questionable firms in terms of comparability). The sample average raw β_e of this Utilities sector in June 2002 was 0.57.

Although the Commission has regularly indicated that an β_e of one or above is most likely too high for the regulated TNSPs, the Commission has provided an β_e biased towards the TNSPs and has not set β_e below one in any revenue cap decisions.[51] Other regulators have set an β_e of less than one for some electricity distribution networks (refer to Appendix 1- Table 3).

8.7.3 Why change?

A report prepared by the Allen Consulting Group for the Commission suggested an β_e for Australian gas transmission companies of just below 0.7 based exclusively on market evidence, with the corresponding figures for the US, UK and Canada all below 0.2.[52] The report advised that caution should be taken with the data from overseas, as equity returns were compared with markets outside Australia, subject to different tax and regulatory regimes.[53] The paper's results provide supporting evidence for the notion that the β_e for Australian utilities is overstated at a value of one.

An β_e of less than one intuitively seems more appropriate for regulated electricity networks in Australia given the level of market risk which they face. These firms are regulated entities guaranteed a revenue stream and the demand for its essential services is inelastic.[54] Providing an β_e of one implies that the regulated companies face the same variability of returns to equity as the market portfolio. Given this, it seems inappropriate to allow an β_e of one for these regulated firms when they are insulated from many of the risks faced by the rest of the market.

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51 For example: ACCC, *Victorian Transmission Network Revenue Caps 2003-2008*, 11 December 2002, pp 22-3; and *South Australian Transmission Network Revenue Cap 2003-2007/08*, 11 December 2002, pp 36-7.

52 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, p. 40.

53 It is expected that the 'cost-plus' style of regulation common in the US will result in a lower β_e.

54 There is some argument that firms subject to regulated revenue caps face less risk than those firms whose prices are regulated. In any case, both forms of regulation could be expected to result in more stable returns to equity than companies that do not posses monopoly characteristics.

De/re-levering process

The only beta that is essential to determining the WACC is the β_e. As mentioned, the asset and debt betas are only required for de/re-levering sample equity betas. In fact, the existence of a β_d in the de/re-levering process has little effect on the resulting benchmark β_e. Therefore, benchmarking an β_e with reference to 'raw' market data, without de/re-levering, would have the significant advantage of simplifying the WACC process considerably. However, as mentioned previously, gearing has a strong effect on a firm's equity beta, and this effect cannot be ignored.

As such, the continued use of a de/re-levering formula such as Monkhouse is necessary if the Commission wishes to refer to market data in its calculation of an β_e. The correct use of the Monkhouse formula to de-lever and re-lever raises a number of issues.

The appropriate gearing ratio to use when de-levering

Given that equity betas are estimated from a firm's returns over a number of years, it would appear inappropriate to simply use its current gearing level. Instead, it would seem more appropriate to use an average of the sample firm's gearing level over the course of the beta estimation period when de-levering a sample β_e.

The debt beta

The Commission currently assumes a zero value for the debt beta in electricity revenue cap decisions. However, this approach may face criticism for assuming that there is no systematic risk associated with debt. Davis states that the value of the debt beta has little effect on the estimated WACC as any change in the assumed value of β_d is offset by a change in the β_e.[55]

The β_d is defined as the systematic risk of debt. According to Davis, default free debt such as the 5 year Government bond rate depicts a certain level of systematic risk. This arises from the observation that the expected returns of long term debt securities vary with the market portfolio. This of itself is a source of systematic risk which is not necessarily related to a project's expected cash flows or the risk of default.[56]

For this reason, a range for the debt beta of between 0.1 and 0.2 acknowledging the systematic risk of debt will reflect the behaviour of debt securities.[57] However, as long as there is consistency in the value of the β_d between the de-levering and re-levering process, its effect on the equity beta is generally negligible.

Beta market data

Based on June, September and December 2002 Australian Graduate School of Management (AGSM) data, a market based proxy β_e can be calculated as shown in

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55 Davis, *Risk Free Interest Rate and Equity and Debt Beta Determination in the WACC*, Report for ACCC, May 2003.

56 This is a concept developed by Campbell and Mei, *Where do betas come from? Asset price dynamics and the sources of systematic risk, Review of Financial Studies* , No 3, 1993.

57 Davis, *Risk Free Interest Rate and Equity and Debt Beta Determination in the WACC*, Report for ACCC, May 2003.

table 5.1 below. For calculation purposes, the β_d was assumed to be zero, and gearing ratios are as at June 2002.[58]

Table 5.1 Sample re-levered equity betas

			June 2002 AGSM data			September 2002 AGSM data			December 2002 AGSM data		
	Company	Gearing level (D / D+E)	Un-adjusted equity beta	De-levered asset beta	Re-levered equity beta	Un-adjusted equity beta	De-levered asset beta	Re-levered equity beta	Un-adjusted equity beta	De-levered asset beta	Re-levered equity beta
Core sample	*Australian Pipeline Trust*	65.40	0.44	0.15	0.38	0.25	0.09	0.22	0.24	0.08	0.21
	Envestra	81.40	0.59	0.11	0.27	0.31	0.06	0.14	0.33	0.06	0.15
	Alintagas	52.60	0.10	0.05	0.12	0.13	0.06	0.15	0.15	0.07	0.18
	Australian Gas Light	56.30	0.36	0.16	0.39	0.09	0.04	0.10	0.08	0.03	0.09
	United Energy	47.60	0.25	0.13	0.33	0.18	0.09	0.24	0.25	0.13	0.33
	AVERAGE	60.66	0.35	0.12	0.30	0.19	0.07	0.17	0.21	0.08	0.19
Additional Firms	*Transurban Group*	92.70	0.42	0.03	0.08	0.70	0.05	0.13	0.69	0.05	0.13
	Macquarie Infrastructure	34.40	0.80	0.52	1.31	0.49	0.32	0.80	0.39	0.26	0.64
	Auckland Int. Airport	37.30	0.64	0.40	1.00	0.55	0.34	0.86	0.53	0.33	0.83
	Hills Motorway Group	54.20	0.60	0.27	0.69	0.54	0.25	0.62	0.36	0.16	0.41
	AVERAGE	54.65	0.62	0.31	0.77	0.57	0.24	0.60	0.49	0.20	0.50
	COMBINED SAMPLE AVERAGES	**57.99**	**0.47**	**0.20**	**0.51**	**0.36**	**0.14**	**0.36**	**0.34**	**0.13**	**0.33**

As an example, by simply increasing the sample size with the inclusion of other infrastructure type firms (whose revenues are less certain than those of a standard regulated utility) it can be seen that the average β_e is inflated, although it remains considerably less than one.[59] The average gearing level of these firms (at 58 % debt) also demonstrates that the Commission's current benchmark (60 %) is quite justifiable. While this similarity means that the average 'unadjusted' and re-levered equity betas are roughly comparable, gearing ratios change over time and this close correspondence may not continue.

According to Davis, the size of the comparator firms trading in the Australian market does not seem sufficient to currently justify its use as the sole input for beta estimation. It is however a relevant source of information about beta values which should not be ignored.[60] To the extent that sample market data indicate a substantial reduction from the typically assumed β_e of one, the Commission is conscious that a transitional/cautious approach may be required such that the Commission take a conservative view to adopting a market based proxy β_e.

One approach is to construct a statistical upper confidence interval based on the sample data. Table 5.2 provides an example of calculating a t-student distribution for upper 95 % and 99 % confidence betas.[61]

58 Gearing levels taken from: Standard & Poors, *Australia & New Zealand CreditStats,* May 2002.

59 Over the last 12 available sets of data (from September 1999), the average (un-adjusted) equity beta has been 0.534 for the Core Sample (however for most of this time, only Envestra and AGL's betas have been published); 0.81 for the additional firms; and 0.71 for the combined sample.

60 Davis, *Risk Free Interest Rate and Equity and Debt Beta Determination in the WACC*, Report for ACCC, May 2003.

61 $\bar{\beta} \pm t_{(\alpha/2)} (s / \sqrt{n})$

Table 5.2 Upper 95 % and 99 % confidence betas

		June 02 AGSM data	Sept 02 AGSM data	Dec 02 AGSM data
Core Sample	Re-levered average β_e	0.30	0.17	0.19
	Standard deviation	0.1103	0.0583	0.0890
	Number in sample	5	5	5
	95 % $t_{(\alpha/2)}$	2.776	2.776	2.776
	95 % confidence β_e	**0.44**	**0.24**	**0.30**
	99 % $t_{(\alpha/2)}$	4.604	4.604	4.604
	99 % confidence β_e	**0.53**	**0.29**	**0.37**
Combined Sample (core and additional firms)	Re-levered average β_e	0.51	0.36	0.33
	Standard deviation	0.4140	0.3078	0.2548
	Number in sample	9	9	9
	95 % $t_{(\alpha/2)}$	2.306	2.306	2.306
	95 % confidence β_e	**0.83**	**0.60**	**0.53**
	99 % $t_{(\alpha/2)}$	3.355	3.355	3.355
	99 % confidence β_e	**0.97**	**0.70**	**0.61**

It should be noted that depending on the confidence interval chosen and the available market data, the constructed confidence β_e may still be less than one but at times it may also be above one.

Alternatively, the Commission can adjust the sample raw betas to reflect the observation that betas tend to one over time (mean reversion) and then undertake the de/re-levering process. That is, raw beta values derived from historical data can be adjusted based on the assumption that beta factors change over time, especially in industries where there is major structural reform in process.[62] Bloomberg adopts this approach and the adjustment is represented as:

Adjusted beta $=$ Raw beta $\times$ 0.67 + 0.33

However, the Commission considers this adjustment to be inappropriate to take account of such tendency, given the objective is to estimate the proxy beta for a regulated electricity transmission business, and the proxy beta is based upon estimates from a selected set of comparable firms.[63] Consequently, the Commission has had regard to raw (unadjusted) beta estimates as shown in the tables above.

β_e measurement difficulties

Various difficulties arise when attempting to calculate the β_e of a firm, as identified by the World Bank. These include the effect on the resulting β_e of such decisions as the interval period selected for the sample, the make-up and weighting of the index with which returns are compared, the frequency of trading of the firms' stock, and the assumed investment horizon.[64]

Despite the measurement difficulties involved in obtaining β_e values, it is difficult to justify disregarding the market data. It is important to remember that equity beta

62 International studies supporting the use of adjusted betas include W. F Sharpe, G. J Alexander and J. V Bailey (1995) and M. E Blume (1975).

63 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities*, Final report for the ACCC, July 2002, pp. 30-33; and
Lally, *The Cost of Equity Capital and its Estimation*, 2000, p.34.

64 The World Bank – Private Sector Development Department, *Regulatory Structure and Risk and Infrastructure Firms: An International Comparison*, December 1996, pp 33-42.

estimates can both under or over-estimate what the ‘true’ figure may be. Regardless of whether or not market data is considered reliable enough to apply, the cost of capital still requires an β_e figure to be estimated to reflect a measure of systematic risk.

Augmenting betas to account for risks

The issue of ‘asymmetric risk’ has been raised as an argument for erring on the higher side when calculating a value for the β_e, or augmenting an β_e once calculated. It has been argued that if the return allowed for regulated firms is inadequate, investment in regulated utilities will be discouraged, with the worst case scenario being a discontinuance of the essential service.[65]

Briefly, most discussions concerning these perceived risks focus almost exclusively on the ‘downside’, while ignoring the possibility of regulatory ‘errors’ or other factors erring in favour of the regulated firm. Although there will always be some uncertainty over future regulatory decisions, there has been little evidence put forward to support claims of a specific ‘regulatory risk’.

In any case, it is doubtful whether artificially inflating the β_e figure used in regulatory decisions (where it is meant to reflect systematic risk) is the ideal means of achieving broad policy objectives such as encouraging investment in infrastructure. Such an approach seems to lack the transparency and accountability of specific and particular adjustments to cash-flows or pass-through allowances, where these are possible, and are considered justified.[66]

8.7.4 What will be the effect of the change?

The use of a market based proxy β_e could point to a reduction in the cost of capital estimate compared to previous decisions. Table 5.3 provides a numerical example on the effect of employing an equity beta lower than one on the unadjusted revenue allowances in the case of the recent ElectraNet revenue cap decision.

Table 5.3 Lower equity beta and its effect on unadjusted revenue allowances

Year	ElectraNet decision	β_e set at 0.70	β_e set at 0.80	β_e set at 0.90
2002/04 revenue allowance ($m)	148.01	141.05	143.37	145.69
2003/04 revenue allowance ($m)	149.78	142.52	144.94	147.36
2004/05 revenue allowance ($m)	159.91	152.09	154.70	157.30
2005/06 revenue allowance ($m)	168.56	160.13	162.94	165.74
2006/07 revenue allowance ($m)	178.71	169.78	172.75	175.73
2007/08 revenue allowance ($m)	178.51	169.25	172.33	175.42

65 The Commission will consider whether specific risk is appropriate for compensation on a case by case basis via the pass-through mechanism.

66 For example, ‘asset stranding’ risk can be accommodated through accelerated depreciation allowances where this is deemed appropriate.

Any reduction in the β_e to below one would, *ceteris paribus*, reduce the rate of return and hence the allowable revenue of a TNSP. This would in turn reduce charges to end-users.

8.7.5 The Commission's preferred position

The Commission is of the view that the current energy market has matured to an extent such that market evidence is sufficient to provide a more credible estimate of the β_e. Although the sample of comparable firms is still relatively small, the market evidence suggests that the Commission has been generous in its previous decisions. This generosity is evident given current market beta estimates, which are lower than those adopted by the Commission. In determining past revenue caps for TNSPs, the Commission has sought not to deter new investment and has been biased towards the TNSP.

As discussed, relevant sample beta estimates are readily available from the AGSM to provide a calculation of a proxy beta through the de/re-levering process. Should additional stock market listing of energy utilities eventuate, then the comparable information available from Australian capital markets will expand even further. Accordingly, the Commission's preferred position is to place greater reliance on market data in calculating an β_e for the TNSPs in future decisions. This would also be consistent with the Commission's approach in calculating forward looking estimates of other parameters based on latest market evidence. Having said this, the Commission notes it would be inappropriate to solely rely on market based betas due to concerns about the reliability and sample size of the current data.

Therefore, in relying on market based data, the Commission proposes to adopt the approach of incorporating an upper confidence interval to calculate a proxy β_e. This approach will also provide the TNSP with the potential for increased returns as the β_e may be above one in certain instances, depending on the constructed confidence interval. These returns will, however, be linked to general market conditions.

Despite this preference, the Commission recognises that there are issues associated with implementing such an approach. For instance, the availability of a limited data set may have implications for a rigorous estimation procedure which incorporate market based measures. Accordingly, the Commission would welcome comments from interested parties on this matter.

The Commission's preferred position

The Commission's initial view is to move towards benchmarking an equity beta from current market evidence and incorporating an upper confidence interval.

Beta issues for consideration

Comment is invited on:

- The appropriate debt beta to use in the de/re-levering process; and

- The Commission's proposed approach in deriving an β_e from market data. Also, given the limited availability of market data, the estimation of the β_e in the future and in the interim.

8.8 Cost of debt

8.8.1 What is the issue?

The cost of debt on commercial loans is the debt margin over the risk free rate and the relationship can be illustrated by the formula:

$r_d = r_f + d_m$

where:

r_d = the cost of debt

r_f = the risk free rate of return

d_m = the debt margin

The cost of debt varies depending on the entity's gearing, its credit rating and the term of the debt. Applying the cost of debt to the asset base, using the assumed gearing ratio, will generate the interest costs (the cost of debt) for regulatory purposes.

8.8.2 How has cost of debt been dealt with to date?

TNSPs tend to propose a debt margin that reflects its actual gearing ratio and a relatively poor credit rating. As with the arguments for a 10 year risk free rate, the TNSPs also contend that the cost of debt should be based on term of debt equal to 10 years, for consistency.

The Commission considers it is appropriate to abstract from the actual cost of debt facing a TNSP, as the actual cost of debt may not reflect efficient financing. Therefore the cost of debt should be determined through reference to a benchmark credit rating and an associated debt margin. Adopting a benchmark credit rating for the TNSP is also more appropriate given that the creditworthiness of the entity is in part under managerial control and the use of a benchmark is consistent with other assumptions.

Table 6.1 sets out the long term credit rating for ten Australian electricity companies that have been assigned a credit rating by ratings agency Standard and Poor's.

Table 6.1 Credit ratings associated with electricity companies

Company	Long-term rating	Actual Gearing (%)
Ergon Energy	AA+	46.9
Country Energy	AA	66.7
EnergyAustralia	AA	52.5
Integral Energy	AA	55.8
SPI PowerNet	A+	82.4
Citypower Trust	A-	65.4
ETSA Utilities	A-	62.4
Powercor Australia	A-	42.9
United Energy	A-	41.9
ElectraNet	BBB+	74.9

Source: Standard and Poor's, *Australian Report Card Utilities*, April 2003

On the basis of this data, the average credit rating of these electricity companies approximates to a credit rating of A. The average gearing for the sample also approximates to 59 % which is close to the assumed benchmark of 60 %. Standard and Poor's states that the A rated entities are generally stable network or transmission businesses.[67]

In its sample of determining the average credit rating for the electricity industry, the Commission has included both private and government backed entities. By simply using stand-alone and private entities, it would provide too small a sample to obtain an average credit rating for the electricity industry. It should be noted that there could be a wide range of factors (other than gearing) relating to why the average credit rating for gas companies, at BBB+, may be lower than electricity companies.[68]

The Commission considers that on the basis of current market information, an A credit rating represents an appropriate proxy credit rating for the benchmark electricity company. The debt margin corresponding to an A rated 5 year term of debt can be determined from the latest data available from sources in the financial market (such as CBASpectrum). This position is consistent with recent revenue cap decisions.

8.8.3 The Commission's preferred position

The calculation of the benchmark debt margin is essentially an empirical matter. It requires the Commission to consider the appropriate benchmark credit rating of the service provider and the debt margin associated with that rating in the market.

67 Standard and Poor's, *Australian and New Zealand Electric and Gas Utilities Ripe for Rationalization*, May 2002.

68 Standard and Poor's, *Energy Australia & New Zealand*, November 2001, p. 14.
In assessing the creditworthiness of Australian gas companies, Standard and Poor's would consider a number of key issues. Specifically, they relate to regulatory risk; counterparty risk; and overall volume of demand for gas.

<u>The Commission's preferred position</u>

The Commission does not propose to vary its current approach to benchmarking the debt margin.

8.9 Debt and equity raising costs

8.9.1 What is the issue?

Debt raising costs

To raise debt, a service provider has to pay debt financing costs over and above the debt margin. One cost that is incurred is the additional payment made to a bank or financial institution for the arrangement of debt.[69] The debt financing arrangement and bank fees are likely to vary between each debt issue and also over time with market conditions. Nevertheless, a benchmark needs to be established to determine a reasonable allowance for revenue calculation.

A variety of different fees and expenses are payable by the TNSP each time it refinances or purchases debt. According to a consultancy undertaken by Macquarie Bank on behalf of the Commission, TNSPs often incur advisory fees, agency fees, arrangement fees, credit rating costs and syndication expenses. In addition, on occasions TNSP's may also be required to pay a dealer swap margin for the transfer from a floating to a fixed rate facility.[70]

Equity raising costs

Equity raising cost must be paid by an entity when it raises capital. These costs are paid to equity arrangers for services such as structuring the issue, preparing and distributing information and undertaking presentations to prospective investors.[71]

8.9.2 How has debt/equity raising cost been dealt with to date?

Debt raising cost

The Commission considers that debt raising costs represent a valid expense incurred by TNSP's when raising or refinancing debt. As with the debt margin, debt raising costs should be based on costs facing a benchmark service provider, rather than reflecting the specific costs incurred by the TNSP. The Commission adopts industry-wide benchmarking, thus offering an incentive for minimising inefficient debt financing. The use of benchmarks should encourage efficient behaviour as it allows the TNSPs to structure its debt to achieve least cost financing options.

In recent decisions, the Commission considered that the determination of these benchmark debt raising costs is an empirical matter which should take into account current market conditions and prices. The Commission researched prevailing market

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69 Macquarie Bank, *Issues for debt and equity providers in assessing greenfields gas pipelines,* report for the ACCC, May 2002, p. 21.

70 *Ibid*, pp. 16, 21.

71 *Ibid*, p. 10

conditions for debt raising fees in 2002 and assessed the transaction costs associated with both bank finance and capital market finance.

At the time evidence suggested that the transaction costs associated with syndicated bank facilities may be higher than fees associated with debt raised on capital markets, however this was unclear given the absence of authoritative data and limited observations. Accordingly, the Commission provided TNSPs an allowance for debt raising costs at the higher end of the range associated with raising debt on capital markets.

Recent revenue cap decisions incorporated these benchmark costs which are consistent with the above considerations. The debt raising costs were calculated as an additional spread to the debt margin in those decisions.

Equity raising costs

As with debt raising costs, the Commission considered it was appropriate to provide a benchmark allowance for equity raising costs in recent decisions. In 2002, the Commission researched equity raising costs and in particular collected the latest information about equity raising costs for several major Australian infrastructure equity raisings. The equity raising costs generally fell between 2.10 and 5.77 % of total equity raised.

On the basis of those data collected by the Commission, a benchmark allowance for equity raising costs (per year) was provided for TNSPs in the operating and expenditure (opex) category.

8.9.3 Why change?

Debt raising cost

Once the benchmark debt raising costs are determined, another issue to consider is where to provide this allowance in the building block approach. The Commission, in past decisions, has added the debt raising costs as an additional spread to the debt margin and accordingly they are recovered through the return on capital allowance.

However, the Commission considers that it may be more appropriate to provide for the spread explicitly as a benchmark allowance in the opex for future decisions as it is an identified cost category. This treatment has the potential to provide a more transparent process and would also be consistent with the Commission's approach to providing equity raising costs in the opex allowance.

8.9.4 What will be the effect of the change?

Debt raising cost

Ultimately a benchmark debt raising cost will still be recoverable by the TNSP whether it is provided in the debt margin or in the opex section. That is, no adverse effect would be borne by the TNSP and, hence, it would be revenue neutral. Instead the explicit treatment of debt raising costs has the potential to provide a more transparent regulatory process for interested parties.

8.9.5 The Commission's preferred position

Debt raising cost

The Commission prefers debt raising costs be treated in the opex allowance rather than as an addition to the debt margin.

This has the affect of being revenue neutral and the allowance provided should be based on current market evidence on transaction costs faced by a benchmark service provider.

Equity raising costs

The Commission prefers to maintain its approach to providing an allowance for equity raising costs.

8.10 Gearing

8.10.1 What is the issue?

Gearing refers to the ratio of debt to equity and is used to weight the costs of equity and debt when formulating a WACC. Capital structure can have a major bearing on not only the debt margin but also the required return on equity (although within reasonable bounds it is unlikely to affect the asset cost of capital or the WACC).

The greater the level of gearing, other things being equal, imply the greater the risk of both debt and equity and therefore the greater the required returns. However, over reasonable ranges, the risk of the total assets does not change and neither would the cost of capital change for the firm's assets.

This is because the change in the weighting of capital from equity to debt maintains a constant risk level for the assets as a whole, even though the beta measures of both debt and equity will increase, and can offset the relative increase in equity and debt costs such that the asset cost of capital or the WACC remains unchanged.[72]

8.10.2 How has gearing been dealt with to date?

A gearing ratio is required to be established for a TNSP to determine the appropriate weighted average cost of debt and equity in the WACC. The Commission can either adopt the actual gearing of the service provider or assume an appropriate benchmark.

A typical capital structure assumed by regulators has been 60 % debt as a proportion of total assets. In theory, the asset cost of capital should be stable within the range of 40-70 %. In the DRP, the Commission noted that while the actual level of debt is at the discretion of the service provider, it would not be using the actual gearing of a service provider. Instead the Commission adopts the use of an appropriate benchmark.

[72] This is an illustration of the Modigliani-Miller proposition that 'a company's value is invariant with changes in its capital structure.

Given that most regulators have assumed a gearing of 60 %, there is little reason to vary from this benchmark.

8.10.3 The Commission's preferred position

The Commission's preferred position is not to change its current approach to benchmarking the gearing of a regulated firm.

8.11 Imputation credits – gamma

8.11.1 What is the issue?

Under the imputation tax system, Australian resident taxpayers can claim a credit against income tax payable on dividends received from Australian companies, to the extent of the income tax that has been paid by those companies in respect of dividend income.

Gamma (γ) represents the proportion of franking credits which can, on average, be used by shareholders of the company to offset tax payable on other income. The γ parameter can be seen as a composite of the proportion of company tax paid that is issued as imputation credits to shareholders, and the utilisation of these credits by shareholders to offset their own tax liabilities. For example, a γ of one reflects full imputation which means that shareholders receive the full benefit of tax paid at the company level (so that the company's pre tax rate of return is the same as its post tax rate of return).[73]

To accommodate dividend imputation, the WACC requires an adjustment (represented as γ) for the value of personal tax credits to maintain consistency between the cost of capital and cash flows which are defined on an after company tax but before personal tax basis.

8.11.2 How has gamma been dealt with to date?

In the DRP, the Commission was of the view that "…the relevant benchmark for regulatory purposes should be based on an assumption of private Australian ownership. The Commission also noted that there is considerable debate as to the value which should be prescribed for γ, and this selection is …ultimately a matter of judgement, having regard to the available empirical evidence".[74]

The Commission currently sets γ at 0.5. This implies that only half of the regulated firm's company tax payable can be issued as imputation credits that are used by shareholders to offset tax payable on other personal income.

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73 Conversely, a γ of zero reflects no imputation which means that shareholders receive no benefit from dividend imputation

74 ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues*, 27 May 1999, p. 82.

8.11.3 The Commission's preferred position

The γ factor incorporates not only what proportion of earnings are paid out as dividends with imputation credits, but also the proportion of the imputation credits that are able to be used. Arguments can be made in favour of adopting a higher γ, particularly when considering Lally's arguments and the impact of the Ralph reforms.[75] Conversely, the actual ownership structure and tax positions of the regulated firms provide some arguments against a rise for γ.

It should be noted that further research is required in this area and no consensus has yet developed among Australian academics or practitioners for adjusting the rate of use of tax credits. Therefore, it seems sensible for the Commission to retain the current assumed value of 0.5 for γ, which maintains a sense of regulatory consistency.

<u>The Commission's preferred position</u>

The Commission's preferred position is to retain the current assumed value of 0.5 for γ.

75 Lally, *The Cost of Capital under Dividend Imputation*, June 2002, p. 43.

Appendix 1 – WACC parameters adopted in regulatory decisions

Table 1 Risk free rate[76]

Entity	Industry	Benchmark bond	Averaging period
ACCC (2002)	Electricity transmission	5-year Commonwealth	10-day average
QCA (2001)	Electricity distribution	10-year Commonwealth	20-day average
ACCC (2001)	Gas transmission	5-year Commonwealth	40-day average
ORG (2000)	Electricity distribution	10-year inflation indexed Commonwealth	20-day average
IPART (1999)	Electricity & Gas distribution	10-year Commonwealth	20-day average
OTTER (1999)	Electricity distribution	10-year Commonwealth	12-month average
ORG (1998)	Gas distribution	10-year Commonwealth	2-month average

Table 2 Market risk premium

Entity	Industry	MRP (%)
ACCC (2002)	Electricity transmission	6.0
IPART (1999)	Electricity & Gas distribution	5.0 – 6.0
OTTER (1999)	Electricity distribution	6.0
ACCC / ESC (1998)	Gas transmission	6.5
ESC (1998)	Gas distribution	6.0

Table 3 Equity beta

Entity	Industry	Equity beta
ACCC (2002)	Electricity transmission	1.0
ESC (2000)	Electricity distribution	1.0
IPART (1999)	Electricity distribution	0.78 – 1.14
OTTER (1999)	Electricity distribution	0.95
QCA (2001)	Electricity distribution	0.71

76 Each decision relates to 5 year regulatory periods.

Table 4 Debt margin[77]

Entity	Industry	Debt margin
ACCC (2002)	Electricity transmission	1.22
ACCC (2002)	Gas transmission	1.59
QCA (2001)	Electricity distribution	1.65
ORG (2000)	Electricity distribution	1.50
IPART (1999)	Electricity distribution	1.0
IPART (1999)	Electricity distribution	0.80 – 1.0
ACCC / ORG (1998)	Gas transmission	1.20
ORG (1998)	Gas distribution	1.20

Table 5 Gearing

Entity	Industry	Debt/Debt+Equity
ACCC (2002)	Electricity transmission	60 %
QCA(2001)	Electricity distribution	60 %
ESC (2000)	Electricity distribution	60 %
IPART (1999)	Electricity distribution	60 %
OTTER (1999)	Electricity distribution	50-70 %
OFGEM (1999)	Electricity distribution (UK)	50 %
IPART (1999)	Gas distribution	60 %
ACCC/ESC (1998)	Gas transmission	60 %
ESC (1998)	Gas distribution	60 %

Table 6 Gamma

Entity	Industry	Gamma
ACCC (2002)	Electricity transmission	0.5
QCA(2001)	Electricity distribution	0.5
ESC (2000)	Electricity distribution	0.5
IPART (1999)	Electricity distribution	0.3-0.5
OTTER (1999)	Electricity distribution	0.5
IPART (1999)	Gas distribution	0.3-0.5
ACCC/ESC (1998)	Gas transmission	0.25
ESC (1998)	Gas distribution	0.5

77 Debt margins reflect different benchmark credit rating assumptions. For example, ACCC (2002) electricity decision is based on benchmark A credit rating while ACCC (2002) gas decision is based on benchmark BBB+ credit rating.