AUSTRALIAN ENERGY MARKET COMMISSION

REVIEW OF THE
ELECTRICITY TRANSMISSION
REVENUE AND PRICING RULES

CONSULTATION PROGRAM

REVENUE REQUIREMENTS:
ISSUES PAPER

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Contents

Abbreviations

ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
BETTA	British Electricity Trading and Transmission Arrangements
capex	Capital Expenditure
CAPM	Capital Asset Pricing Model
CFE	Comision Federal de Electricidad (Mexico)
Code	National Gas Code
Commission	See AEMC
CPI	Consumer Price Index
CRE	Mexican Energy Regulatory Commission
CSC/CSP	Constraint Support Contract/Constraint Support Payment
DEA	Data Envelope Analysis
DRP	Draft Statement of Principles for the Regulation of Transmission Revenue (May 1999)
Draft SRP	draft Statement of Principles for the Regulation of Electricity Transmission Revenues (August 2004)
EMA	Energy Market Authority (Singapore)
EPO	Electricity Pricing Order (South Australia)
ESC	Essential Services Commission (Victoria)
FERC	Federal Energy Regulatory Commission (USA)
FTR	firm transmission rights
IPART	Independent Pricing and Regulatory Tribunal (NSW)

ISO	Independent Systems Operator
kV	Kilovolt
MAR	Maximum Allowed Revenue
MCE	Ministerial Council on Energy
MNSP	Market Network Service Provider
NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NETA	New Electricity Trading Arrangements
NGC	National Grid Company (Britain)
NPAM	Network Performance Assessment Model (Singapore)
NVE	Norwegian Water Resources and Energy Administration
OATT	Open Access Transmission Tariff (USA)
ODV	Optimised Deprival Value
Ofgem	Office of Gas and Electricity Markets (UK)
opex	Operating Expenditure
PASA	Projected Assessment of System Adequacy
PTRM	Post Tax Revenue Model
QCA	Queensland Competition Authority
RAB	Regulatory Asset Base
RoR	Rate of Return
Rules	National Electricity Rules
SCO	Standing Committee of Officials

SRP	Statement of Principles for the Regulation of Electricity Transmission Revenues (December 2004). The SRP comprises a background paper and a consolidated version of the principles.
TFP	Total Factor Productivity
TNSP	Transmission Network Service Provider
TPA	Trade Practices Act 1974 (Cth)
TUoS	Transmission Use of Service
WACC	Weighted Average Cost of Capital

Introduction

The National Electricity Law requires the Australian Energy Market Commission to amend the National Electricity Rules governing the regulation of transmission revenue and prices before 1 July 2006. The AEMC is conducting a review that includes broad consultation, to develop a Rule change proposal and draft Rules.

As the first phase of consultations, the AEMC published a Scoping Paper in July 2005 seeking comments from all stakeholders on what should be considered as part of the Review. In the Scoping Paper the Commission also sought comments on undertaking the Review in two stages, with the first stage (revenue regulation) to be completed by 1 July 2006 and the second stage (pricing) to be completed by 1 January 2007.

This Issues Paper seeks comment regarding the revenue aspects of the Review. Further consultation will occur when an additional Issues Paper is published in November on the pricing aspects of the Review.

As the first major review since the establishment of the new national regulatory regime in July this year, the Scoping Paper and this Issues Paper have been framed in an open way to seek substantial and broad ranging feedback from stakeholders.

The Commission has an open mind about the approach to transmission revenue regulation that may be adopted in the revised Rules. This consultation approach is a valuable opportunity for the Commission to listen to the comments and opinions of all stakeholders.

This Issues Paper reflects matters identified in stakeholder submissions on the Scoping Paper and the Commission's preliminary research and analysis on matters of significance.

Key themes raised in submissions include the need for regulatory arrangements that achieve a better alignment between investments in and operation of transmission networks and the interests of market participants and electricity consumers. A second important theme is the desire to provide greater clarity, certainty and consistency in the application of regulation.

The Commission will have particular regard to the substantial experience in the practice of transmission revenue regulation since the commencement of the National Electricity Market, including the development and application of the Statement of Regulatory Principles by the Australian Competition and Consumer Commission.

This Paper raises questions, alternatives and options in a number of areas to elicit views from stakeholders.

Once the submissions on the Issues Paper have been received and considered, and the Commission has conducted its own analysis, the Commission will commence the formal Rule change process in February 2006, accompanied by a Commission decision paper setting out the reasons for the proposed Rules.

Interested stakeholders are invited to make comment on the issues outlined in this Paper. Submissions should be received by 5 pm on 16 November 2005. Submissions can be sent electronically to submissions@aemc.gov.au or by mail to:

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1. Scope of the Review

The Australian Energy Market Commission (AEMC or Commission) has taken into account the comments of stakeholders on its Scoping Paper together with the National Electricity Law (NEL) requirements in coming to a preliminary view on the appropriate coverage of this review (the Review).

This Issues Paper sets out those issues that appear to be within the scope of the Review, and highlights a series of questions where the Commission is seeking feedback from stakeholders in order to assist it in considering either possible changes to the National Electricity Rules (the Rules), or confirmation of existing arrangements.

After clarifying the scope of the Review, it is essential to clearly identify the objectives and context of the Review. Chapter 2 examines this area, with chapter 3 outlining the requirement for regulation of transmission in the context of the economic characteristics of transmission services.

Chapters 4 to 7 discuss the issues surrounding the approach to regulation, including the form of regulation (chapter 4), scope of regulation (chapter 5), use of incentives and performance obligations (chapter 6), and the determination of cost components (chapter 7).

The final two chapters examine the fundamental issue of the extent of discretion for the regulator to be incorporated when designing the Rules (chapter 8), and the regulatory procedures to be adopted (chapter 9).

1.1. Key Themes of the Review

In considering the submissions on the Scoping Paper the Commission has identified two key themes that it considers may be relevant in testing whether any proposed Rules will contribute to the achievement of the National Electricity Market (NEM) objective. These themes are:

1. Aligning the long term incentives of transmission service providers with those of other market participants including end-use consumers. It is particularly important that network owners and other investors have appropriate incentives to develop and operate the transmission network in an efficient manner so that prices reflect least cost production and delivery of power to end-users at the levels of reliability and security they require; and

2. Increasing the clarity, certainty and transparency of the regulatory approach, so as to provide a more certain regulatory environment in which investors can make efficient

investment decisions which deliver market outcomes that better serve the long term interests of consumers[1].

These themes are consistent with the submissions on the Scoping Paper.

In line with the emphasis in the NEM objective on efficiency for the long term benefit of consumers, an important theme arising from submissions is the need for the Rules to facilitate efficient development and operation of the electricity transmission system through effective incentives and processes.

Efficient incentives and processes should work towards reducing or eliminating network constraints, where it is efficient to do so and thereby contribute to efficient operational and pricing outcomes in the wholesale and retail markets.

Effective incentives and processes also need to give sufficient weight to transmission alternatives, such as embedded generation or demand management initiatives and alternative energy sources.[2]

The Commission also intends to examine the incentive properties and relative merits of both the *ex ante* and *ex post* regulatory approaches to the assessment of efficient investment, including the efficacy of the *ex ante* approach to capital expenditure developed in the Statement of Principles for the Regulation of Electricity Transmission Revenues (SRP), and the circumstances under which either of these approaches, or a combination of the two, may be appropriate.

The interaction between the revenue determination process and the Regulatory Test – which is itself a form of *ex ante* process for determining investment efficiency and plays a key role in the evaluation of transmission alternatives - will warrant careful attention in this Review. However, the nature and form of the Regulatory Test will not formally be considered; rather, its substance will be addressed as part of a separate process to be initiated by the Ministerial Council on Energy (MCE). Some submissions to the Scoping Paper, however have suggested that the Review process be expanded to include a broader review of the Regulatory Test.[3] These issues are discussed in chapter 7.

Further, a number of submissions in response to the Scoping Paper expressed concerns about the uncertainty of the process for conducting a transmission revenue determination. Such uncertainty could introduce avoidable risks for investors and users, and result in investment inefficiencies. While the regulatory approach selected to provide these industry assurances may not differ greatly from current practice, the industry view seems to be that formalising these practices will provide greater certainty and consistency[4]. The Review

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1 The focus on the long term benefit of consumers is supported in a number of submissions to the Scoping Paper, including the Energy Users Association of Australia, p.1; Energy Action Group, p.1; Energy Markets Reform Forum, 17 August 2005, p.2; Energy Intensive Industries Alliance, p.2

2 NGF, Submission to the Scoping Paper, 19 August 2005, p.5; Smiles, B. Submission to the Scoping Paper, 19 August 2005, pp.1-2; The Group, Submission to the Scoping Paper, 22 August 2005, pp.5-6

3 AGL, Submission to the Scoping Paper, 22 August 2005, p.1; CS Energy Submission to the Scoping Paper, 19 August 2005, p.1

4 Energy Action Group, Submission to Scoping Paper, 25 August 2005, p.7; Energy Networks Association, 19 August 2005, p.2

represents an important opportunity to consider the balance of regulatory discretion and prescription that should be provided in the Rules, and in doing so ensure the Rules provide an appropriate level of predictability in economic regulation. These issues are discussed in chapter 8 of this Issues Paper.

The Commission will need to take into account the large amount of work already undertaken in this area, particularly that developed by the Australian Competition and Consumer Commission (ACCC) including the regulatory practices and processes reflected in the SRP. This is discussed further in the following two chapters.

However, while having careful regard to that experience, the Commission is required to develop Rules that comply with both the specific requirements in the NEL, and the NEM objective and associated Rule making test.

An important issue for this Review may be to clarify the scope of transmission assets or services that are to be subject to direct revenue or price regulation. In circumstances where there are substantial market power problems, there is a case for economic regulation. It may therefore be necessary to delineate assets and services accordingly. At the same it may be worth considering whether efficiency could be enhanced by applying different forms of regulation to different transmission services with the aim of reducing the overall regulatory burden. To this end the circumstances in which different forms of regulatory controls may be appropriate are discussed in chapters 4 and 5.

The convergence of energy markets was also identified in submissions as an important consideration for this Review.[5] The expected transfer of responsibility for the regulation of electricity distribution and all covered gas pipelines to the Australian Energy Regulator (AER), and for the Rules governing these areas to move under the jurisdiction of the AEMC, underscores the importance of considering the extent to which similar Rules may be applicable across sectors. While there have been suggestions that the AEMC should delay making any changes to the Rules governing transmission regulations until gas regulatory arrangements have been finalised[6], the Commission considers that this is neither necessary nor feasible. However the Commission will have regard to the MCE's ongoing policy process on gas access regulation.

Nevertheless, it may be important for the Rules to be competitively neutral in their approach and impact between the different forms of energy. This implies, for example, that where costs are taken into account, such as for asset values, similar principles may apply in the Rules and regulatory approaches.

Many procedural issues may also be common between the regulation of electricity transmission and the arrangements for distribution and gas pipelines. These include:

- appropriate levels of discretion around procedural requirements, including the extent of discretion for the AER to modify or reject a proposal;

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5 Bardak Group, Energy and Management Services, Submission to the Scoping Paper, 11 August 2005, p.11

6 AGL, Submission to the Scoping Paper, 22 August 2005, pp.1-3

- the timing and process for reviews;
- the degree of transparency in regulatory decisions;
- the financial framework for determining allowed revenues; and
- the provision of regulatory information.

These issues are addressed in chapters 8 and 9.

Although the scope of the Review is limited to making Rules in relation to the listed matters 15-24 in Schedule 1 of the NEL, many other provisions in the Rules affect, or are affected by, those dealing with transmission revenue and price regulation. The Scoping Paper posed a number of questions regarding the boundaries of the Review, and the Commission has considered these further in light of the responses received. Several submissions were concerned that the Scope not be unduly broad and risk delaying clarification of the Rules[7]. This must be balanced with the need to consider the interactions with broader issues such as the Regulatory Test[8] so that there are no unintended consequences of any changes to the Rules.

In addition to the Regulatory Test and its interactions with the revenue determination process identified above, other matters in the current Rules are relevant for this Review but fall outside the AEMC's power to initiate Rules. They include:

- the National Electricity Rules, Chapter 5 provisions in relation to connections and network performance standards are not within the scope of this Review, although the arrangements for assessing and providing incentives for efficient operation of and investment in transmission networks do need to be considered. These issues are addressed in this Paper in chapter 6;
- the role of and provisions for Market Network Service Providers (MNSPs) are outside the scope of the Review[9], but the revenue determination principles for MNSPs converting to regulated status will need to be addressed as part of the revised Rules. This issue is addressed in chapter 7; and
- the transmission planner of last resort role is also outside the scope of this Review, but the extent to which the totality of investment incentives for Transmission Network Service Provider (TNSPs) are sufficient, as well as measures to address any gatekeeper problems for new investment, need to be addressed by the Review. These issues are addressed in chapters 6 and 7.

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7 Ergon Energy, Submission to the Scoping Paper, 19 August 2005, p.1; Hydro Tasmania, Submission to the Scoping Paper, 18 August 2005, p.1

8 VENCorp, Submission on the Scoping Paper, 19 August 2005, p.3

9 Several submissions to the Scoping Paper supported the view that MNSPs are outside the scope of this Review, including AGL, 22 August 2005, p.7; NGF, 19 August 2005, pp.3-4; Transend Networks, 19 August 2005, p.2; Energex, 19 August 2005, p.3

2. Objectives and Context for the Review

This Review of the National Electricity Rules governing transmission revenue and pricing regulation has been triggered in response to the provisions in the NEL[10] that require the AEMC to review and, as required, amend the relevant provisions in the Rules.

The NEL both initiates a process and defines the subject matter for this Review[11], and sets out the NEM objective and Rule making test to which the AEMC must have regard when developing, assessing and determining any proposed Rule changes, including those arising from this Review.

This chapter discusses the requirements of the NEM objective and Rule making test in the context of both this Review and the wider policy environment.

2.1. The NEM Objective and Rule Making Test

The NEM objective, by which the AEMC must be guided when performing any of its functions and exercising its powers, is set out in the NEL as follows:

> *"The national electricity market objective is to promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system."*

In developing, assessing and determining any proposed Rule changes, including Rule changes arising from this Review, the AEMC is subject to a companion obligation in the form of the Rule making test, which states:

> *(1) The AEMC may only make a Rule if it is satisfied that the Rule will or is likely to contribute to the achievement of the national electricity market objective.*
>
> *(2) For the purposes of subsection (1), the AEMC may give weight to any aspect of the national electricity market objective as it considers appropriate in all the circumstances, having regard to any relevant MCE statement of policy principles.*

The Rule making test and the NEM objective are the critical reference points for this Review. The Commission's current interpretation of the NEM objective, in the context of this Review is discussed below.

The NEM objective is founded on the concept of economic efficiency, with explicit emphasis on outcomes, ie, the long term interests of consumers. It also emphasises that the interests of consumers encompass not only the price at which services are provided, but also the quality, reliability, safety and security of the electricity system.

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10 The NEL is contained in the Schedule to the National Electricity (South Australia) Act 1996 as amended by the National Electricity (South Australia) New National Electricity Law Amendment Act 2005

11 For a fuller discussion of these requirements, refer to Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules, Initial Consultation: Scoping Paper*, July 2005, p.10

Economic efficiency has three principal dimensions, (referred to as productive, allocative and dynamic efficiency) and there is some potential for trade-offs to arise between them. Each dimension is captured by specific references in the NEM objective. For example:

- efficiency in the use of electricity requires that the system is operated on a 'least cost dispatch' basis (productive efficiency), and that the quality, reliability, security and safety of electricity services are both provided and priced in line with the preferences and valuations of consumers (allocative efficiency);

- efficient investment in electricity services captures the dynamic component of efficiency, and is met by ensuring there is sufficient incentive and financing capacity to undertake efficient long term investments and to adopt innovations which take advantage of technological developments in order to meet society's changing needs over time; and

- the reference to the long term interests of consumers confirms that the delivery of efficient market outcomes requires a longer term perspective which recognises the need for efficient incentives and outcomes for producers of electricity services in order to serve the interests of electricity consumers on a continuous basis over time.

In practical terms, the NEM objective is a means to the ultimate end of serving the interests of consumers and the community as a whole in receiving efficiently priced, reliable and secure electricity services. That implies an electricity market in which:

- electricity services are supplied in the long run at least cost, taking into account the cost complementarities across each of the generation, network and retailing components; and there is an appropriate emphasis on the efficient delivery and pricing of the non-price elements of service that consumers value;

- the efficiency of transmission investment is assessed by reference to the maximisation of both producer and consumer surplus compared with a range of alternatives (in line with the basic architecture of the Regulatory Test), in order to avoid inefficiently crowding out non-network alternatives; and

- where there is a potential trade-off between the long term benefits to consumers, say arising from investment and innovation in network, metering or generation technologies, and the short term benefit of setting prices below their long run economic cost, the benefits of the longer term outcomes should receive due weight.

The Rules for transmission revenue regulation have a critical role to play in furthering these objectives. First, the primary function of regulation is to address market power and promote competition with respect to the price and quality of supply. Therefore the substance of any Rule change proposals must be designed so they are likely to improve the efficiency and performance of the electricity market as compared with the *status quo* regulatory arrangements.

Second, the Review will need to consider whether the means by which the Rule change proposals seek to achieve the desired outcomes or processes result in regulatory arrangements that are clear, transparent, and predictable. These attributes of good regulation are required to ensure that markets and market participants are well informed, thereby enhancing:

- the efficiency of market related decision making by investors and consumers, whether in relation to transmission directly, to generation or retailing services that depend on transmission, or in relation to transmission alternatives;
- the willingness of investors to commit capital to the NEM, thereby reducing its long term cost; and
- the role of transmission revenue and pricing outcomes in signalling investment opportunities to potential investors and signalling to consumers the cost of their energy usage choices.

2.2. Policy Context

The Commission's Scoping Paper highlighted[12] the significant policy and regulatory decision-making, statements of principle, analysis and consultation that has occurred over the past eight or more years, and which has direct or indirect relevance for this Review. These developments are listed without further elaboration below:

- the national energy market reforms in general, and the expressed intention in the MCE's Communiqué of 11 December 2003 to move regulation of electricity distribution and covered gas pipelines to the AER, and to bring the Rules governing these services under the auspices of the AEMC;
- the public debate on infrastructure regulation[13], including the Productivity Commission's recommendations for reform of the Third Party Access Code for Natural Gas Pipelines, and recent consultation those recommendations by the MCE's Standing Committee of Officials (SCO);
- the MCE Statement on NEM Electricity Transmission[14], including the consideration of principles for the Regulatory Test new electricity transmission investment, regional boundary structures and the criteria that should apply for amending boundaries, and the role of merits review;
- the debate on the merits of moving towards a nodal pricing regime for the energy market and the related questions of the most appropriate transmission pricing and property rights arrangements for a more decentralised NEM;

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12 Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules, Initial Consultation: Scoping Paper*, July 2005, section 1

13 Prime Minister's Exports and Infrastructure Taskforce, *The Exports and Infrastructure Taskforce Report*, May 2005, available at http://www.infrastructure.gov.au/

14 MCE, *Statement on NEM Electricity Transmission*, May 2005

- reviews of the regional boundary structure[15], and the regulatory and institutional framework for transmission[16];

- the review of transmission pricing (but not revenue regulation) undertaken by National Electricity Code Administrator (NECA) around the time the NEM was established[17]; and

- the ACCC's Statement of Principles for the Regulation of Electricity Transmission Revenues and its accompanying Post Tax Revenue Model (PTRM).

In addition to the material referenced above and discussed previously in the Scoping Paper, the AER has since published[18] its Compendium of Transmission Guidelines. This brings together a complete set of reference documents relevant for the regulation of electricity transmission, and includes:

- the Statement of Principles for the Regulation of Electricity Transmission Revenues;

- the Regulatory Test;

- Service Standards Guidelines;

- Guidelines for the Negotiation of Discounted Transmission Charges;

- Transmission Ring-Fencing Guidelines;

- Information Requirements Guidelines; and

- the Post Tax Revenue Model and a handbook explaining the model.

The AEMC recognises that these references are the product of extensive consultation and debate over an extended period of time, and they will be carefully considered in the course of the Review. The experience, analysis and practices reflected in these documents will provide the starting point for the identification and analysis of relevant issues. This will inform the development of any improvements to the Rules.

2.3. Revenue and Pricing Regulation Interactions

As foreshadowed in the Scoping Paper, the transmission revenue and pricing components of this Review are being conducted in two integrated strands, principally for the purposes of

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15 NECA, *The Scope for Integrating the Energy Market and Network Services*, Vol 1, Draft Report, October 2000. CRA, *NEM – Transmission Regional Boundary Structure*, Consultation Draft, September 2004; CRA, *NEM Regional Boundary Issues: Theoretical Framework Report*, Final Report, September 2004; CRA, *NEM Regional Boundary Issues: Modelling Report*, Final Report, September 2004

16 Firecone, *Regulatory and Institutional Framework for Transmission*, Final Report, November 2004

17 NECA, *Transmission and Distribution Pricing Review*, Final Report, July 1999

18 Australian Energy Regulator, *Compendium of Electricity Transmission Regulatory Guidelines*, August 2005

efficient management of an extensive and complex set of issues[19]. However, it is important to be clear from the outset about the areas of interaction between these two strands, and how these interactions will be taken into account.

The most important areas of interaction include:

- the impact and adequacy of existing administrative decision-making criteria or processes that influence the efficiency of investment to be remunerated under the transmission revenue regulation framework and in doing so may reduce the need for prices to perform this role (eg, the Regulatory Test and the approach to assessing efficient investment, the reliability standards and processes, and the limited availability of access property rights);

- the impact of potential market developments – for the example, the introduction of a firm access regime would alter the nature and quantum of transmission revenue requirements for TNSPs, and the incidence of the prices to recover the costs of these additional services;

- decisions on the appropriate form of price control (revenue or price caps), which may provide greater or lesser incentives for TNSPs to develop efficient tariff structures and/or adopt efficient demand management opportunities; and

- decisions on the degree of flexibility TNSPs should have in determining the structure of transmission prices under a given revenue or price cap.

These relationships will be dealt with by identifying and dealing with them as they arise in the course of the Review.

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19 Many submissions supported the two stage process, including Energy Networks Association, 19 August 2005, p.2; Electricity Transmission Network Owners' Submission on AEMC Scoping Paper, August 2005, p.1; VENCorp, 19 August 2005, pp.2-3; Hydro Tasmania, 18 August 2005, p.1

3. Requirement for Transmission Regulation

3.1. Transmission and the Market

A consistent theme of electricity sector reforms across the world over the past 15 to 20 years has been the introduction of competition in the generation and retailing elements of the supply chain. Competition has been the principal means for driving efficiency in both the operation of existing generation assets, and for making decisions on when, where and what form of investment in new capacity should occur.

For the retailing function, competition has stimulated the development of financial and hedging instruments for the better management of the inherent cost of the risks arising in the wholesale market. It has also allowed retailers to present the costs of managing wholesale market risk to customers in ways that allow them to choose the combinations of cost, service and risk they prefer. Retail competition has also been a catalyst for unwinding cross-subsidies across different customer classes and promoting more cost-reflective pricing, which in turn enables consumers to respond to relative supply scarcity by adjusting their consumption.

The transmission network is crucial in facilitating competition and, subsequently, efficient resource use in the electricity wholesale and retail markets. It does this by enabling third parties to trade with other buyers and sellers located elsewhere on the national grid.

These increases in efficiency and the resulting improvements in service and prices to customers have been made possible by three key electricity sector reforms:

- structural reform focused on separation of the potentially competitive activities of generation and retailing from the naturally monopolistic transmission system elements - with the purpose of preventing an otherwise vertically integrated business from undermining competition by setting excessive prices or unreasonable terms for competitors to use its network assets. More recently attention has turned to the separation of distribution and retailing to improve retail competition;

- structural reform of generation and retailing assets, involving the horizontal separation of previously aggregated generation and retail businesses into a number of competing businesses and the establishment of a wholesale exchange so that generation output can be bought and sold in a market - the focus of these reforms has been to harness the forces of competition so as to drive costs and prices to efficient levels, and to provide price signals for future investment decisions for those services; and

- the introduction of independent economic regulation as the means of addressing the undesirable consequences of the market power of the transmission and distribution businesses, while ensuring there is sufficient incentive and capacity to undertake long term investment.

An efficient, robust and independently operated transmission system providing non-discriminatory access to all users is essential for achieving the efficiency, reliability and security gains offered by a disaggregated and competitive electricity market. Where the regulatory and other arrangements governing transmission fall short of this goal, not only does this give rise to inefficiency in the transmission service itself, it can also result in significant distortions and inefficiencies in the generation and retail elements of the market, to the detriment of consumers.

The nature of the interactions between the development and operation of the transmission system and the costs and returns of generation and retailing businesses can be very complex, but in simplified, economic terms they can give rise to inappropriate decisions on transmission capacity and pricing – the amount of transport service available and its cost. This could distort operations, pricing and investment outcomes in the wholesale energy market through:

- under-investment in transmission, and so the existence of inefficient constraints which can manifest itself as inefficient use of generation capacity. Transmission constraints may also provide generators with an undue ability to sustainably raise prices above costs which results in a degradation of economic welfare; or

- over-investment in transmission capacity which can distort the optimal (least-cost) mix of investment in generation, demand management and alternative energy sources, also resulting in lower economic welfare.

The significance of these interactions for the competitive elements of the electricity system, together with the market power of the core transmission service, are the main reasons why market participants are concerned that the regulatory arrangements for transmission promote efficient behaviour across the market.

3.2. Economic Characteristics of Transmission

The electricity transmission system is characterised by two distinct physical and operational attributes that give rise to substantial market power for TNSPs, the exercise of which can result in inefficient market outcomes.

First, there are very significant economies of scale in the provision of transmission capacity. In the simplest terms, transmission lines are much cheaper to build - on a unit cost basis - the greater is their capacity. This means it is more efficient for there to be just one or a small number of transmission service providers (or at least a single planner), thus giving rise to concerns that the most efficient market structure may also provide the capacity and incentive for monopoly pricing or other forms of market distorting behaviour.

Second, there are significant network externalities. The nature of power flows across the transmission network means there are very strong interrelationships between what happens in one part of the network and the effect elsewhere. For example, the development and operation of the transmission system elements in one part of the interconnected network may significantly (adversely or favourably) affect the capacity and value of transmission elements in another part of the network. Given these complex interactions it is difficult to determine which party created costs or conferred benefits on other network users. This feature makes it very difficult to introduce market mechanisms to provide incentives to develop and operate the transmission network. Markets only work effectively if producers can identify and charge the beneficiaries of their production activities.

These two features combine to provide TNSPs with substantial market power. In the NEM this has generally led to the development of strong regulatory controls to ensure that TNSPs behave in a manner that is likely to deliver efficient outcomes. Broadly, these regulations govern:

- the amount of transmission capacity that is to be built, as largely dictated by minimum service standards, and subject to passing certain economic efficiency tests;
- a wholesale market arrangement that includes a set of pre-defined rules that govern the manner in which scarce transmission capacity is allocated between competing users, and an independent market and system operator (NEMMCO) to ensure that these rules are applied in a non-discriminatory manner; and
- controls over the prices that TNSPs can charge network users and transmission service quality.

The economic characteristics of electricity transmission systems described in this chapter are the source of an important economic distinction between gas and electricity transmission. Gas pipelines also enjoy large-scale economies – the unit cost of capacity declines significantly as pipelines become larger – but the network externalities are much less acute. Pipeline systems are generally designed to deliver gas from production source to point of demand, and typically are less interconnected. This critical difference means that bulk gas transport systems are more amenable to a greater role for market drivers of both operating and investment decisions as opposed to regulation.

3.3. Role and Extent of Economic Regulation

As noted above, the consequence of both the economies of scale and network externalities inherent in any electricity transmission system is that service providers are likely to have a substantial degree of market power in the provision of particular transmission services. When a firm has market power, it is largely insulated from the constraints imposed by competition, either by actual rivals in the market or by the fear of new entry. Such firms have the ability to raise prices substantially above long run costs, and to undertake production decisions that no longer have primary regard to the needs of consumers.

It is this potential for a social loss from inefficiency that motivates the regulation of transmission services that are characterised by market power. As a general proposition, the greater the potential efficiency loss, the greater the likelihood that more intrusive forms of regulation, such as price or revenue cap regulation using a building block approach, will improve on market outcomes. However, economic regulation is, in itself, a costly and imperfect exercise. Whilst it can, in principle, improve on problems of excessive pricing and under-supply, it comes at the expense of significant regulatory costs and the potential for regulatory error.

In some circumstances, the regulatory costs incurred in pursuing a competitive market-like outcome may outweigh the benefits. In any event, there are intrinsic limits on the extent to which regulation can improve on market outcomes.

The less significant is the market power and so the potential for cost inefficiency and distortions to resource use, the greater will be the case for less intrusive forms of regulation, or no regulation. The challenge is to strike the optimal balance between the efficiency costs of market power – which vary from one circumstance to another – and the costs of regulatory measures adopted to correct it.

Similar principles apply when considering the most appropriate form of regulation to apply or whether to regulate at all. Regulatory outcomes are more likely to fall short of the goals set for them as the arrangements become more complex and their administration is subject to greater cost and uncertainty and reduced transparency. This implies that the extent of the likely market failure needs to be greater to justify more complex and intrusive regulatory arrangements.

Recognising these trade-offs, it may be possible to envisage alternative arrangements for regulation of transmission services with the degree of regulatory intrusion depending upon the degree of market power held by the service provider in the provision of those services. Some transmission services are likely to be characterised by substantial market power, while others may be more amenable to contestability or commercial negotiation.

This suggests that while there is likely to be a case for continuing direct revenue or price regulation of those transmission services that exhibit substantial market power, there may be a case for less intrusive or even no regulation for some transmission services. The intention to adopt less intrusive forms of regulation in appropriate circumstances underlies the current provisions in the Rules that exclude charges for generator access services from consideration in the setting of prescribed prices or incorporation of the associated costs and revenues into TNSPs' revenue caps.

The categorisation of transmission services depending upon the degree of market power held by the service provider could give rise to a multi-tiered regulatory structure, with regulatory solutions tailored to the market circumstances of different types of services. The objective of such arrangements would be to reduce the cost and distortions caused by regulation. Each arrangement should be assessed against a reference point of no greater cost or distortion arising under a more market based approach.

In a similar vein, procedural or other requirements imposed by regulation may seek to encourage a wider range of technical solutions to the provision of transmission services. For example, regulation can ensure that proper consideration is given to generation and demand management options, or the efficient use of alternative energy sources, to provide a complementary or substitute service to traditional transmission solutions, as suggested in a number of stakeholder submissions.[20]

[20] Total Environment Centre, 22 August 2005, pp.2-3

It is important to recognise, however, that arrangements such as multi-tiered regulatory arrangements and procedural rules or incentives directed towards ensuring that the transmission investment evaluation process gives sufficient weight to potential alternatives, may themselves give rise to greater regulatory complexity and cost.

In evaluating these issues, it will be important for the Review to focus on the likely effect of each regulatory option on the achievement of the NEM objective, as compared with maintaining the status quo or selecting one of the alternative regulatory or market based options being considered.

4. Form of Regulation

The NEL requires the Commission to make Rules in relation to the mechanism or methodologies for deriving the maximum allowable revenue, or prices, to be applied by the AER in making a transmission determination.[21] This is referred to in this Paper as the form of regulation.

Different forms of regulation will have different impacts on the incentives of TNSPs. It will be important for the regulator to find ways to constrain the exercise of market power by monopoly businesses while still encouraging the TNSPs to invest in and operate the network efficiently. In that way, the form of regulation can better align the incentives of the regulated businesses with the wider interests of market participants, in a situation in which future market outcomes are uncertain and the regulator's information is limited. It is important to consider what incentives the regulatory regime should provide to the regulated business and the way in which such incentives can best be delivered.

4.1. NEL Requirements

The NEL places a range of specific obligations on the AEMC in relation to the making of the transmission revenue Rules.

Section 35(3) states that Rules made by the AEMC must, among other things:

- provide a reasonable opportunity for a regulated transmission system operator to recover the efficient costs of complying with a regulatory obligation (NEL, s35(3)(a));

- provide effective incentives to a regulated transmission system operator to promote economic efficiency in the provision by it of services that are the subject to a transmission determination (NEL, s35(3)(b)); and

- require the AER, in making a transmission determination, to make allowance for the value of assets forming part of a transmission system owned, controlled or operated by a regulated transmission system operator, and the value of proposed new assets to form part of that transmission system, that are, or are to be, used to provide services that are the subject of a transmission determination (NEL, s35(3)(c)).

4.2. Existing Arrangements

The current Rules effectively prescribe that transmission revenue regulation be undertaken by means of a CPI-X building block approach. Specifically, they require that:

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21 NEL, Schedule 1, Item 20

- a CPI -X form of regulation be applied to revenues for prescribed transmission services;[22]

- the revenue control shall apply for not less than five years, with scope for revocation of such controls only in the case of material error, false or misleading information or a substantial change in ownership;[23] and

- that certain matters be considered in determining a revenue cap, including: asset valuation; demand growth; service standards; the potential for efficiency gains; fair and reasonable returns; taxes; network support payments to generators; commercial viability and financial indicators.[24]

The basis of the building block approach is the establishment of forward looking estimates of the costs of providing the relevant service. Each cost category – operating expenditure, return on capital, deprecation and tax – is combined to derive a forward looking estimate of the revenue required to operate the network business on an efficient basis during the regulatory period. The building block approach to determining revenue or price controls for regulated infrastructure services has widespread application throughout Australia and other countries.

One issue is whether or not the description of the building block regulatory approach in the current Rules is complete. For example, the Rules make no reference to the need to allow for depreciation in determining allowed revenues or the appropriate treatment of company taxation.[25]

In addition, the approach to transmission revenue regulation contained in the SRP has moved away from that set out in the Rules in at least one important respect, ie, the use of a lock-in approach to determining regulatory asset values rather than the periodic re-optimisation implied by the deprival value approach, which the Rules describe as the "preferred approach".[26] It is also arguable that aspects of the *ex ante* approach to assessing capital costs set out in the SRP are not fully consistent with the current Rules.

These considerations suggest that, if the current form of the building block approach to the regulation of core transmission services embodied in the SRP is retained, there is scope to improve the clarity and precision of the Rules so as to bring them into line with current practice.

The Rules allow for lighter handed regulatory approaches to be applied to services for which the AER considers there is sufficient competition.[27] However, the Rules do not set out

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22 Clause 6.2.4(a) National Electricity Rules. The Rules define 'prescribed transmission services' as '*transmission services* provided by *transmission network* assets or associated *connection assets* to which a *revenue cap* applies'.

23 Clauses 6.2.4(b), 6.2.4(d), National Electricity Rules

24 Clauses 6.2.3(d)(4), 6.2.4(c), National Electricity Rules

25 Both of these issues are discussed further in Chapter 7.

26 SRP p.10; Rules clause 6.2.3(4)(iv)

27 Clause 6.2.3(c), National Electricity Rules

criteria for assessing the extent of contestability or the form(s) of regulation to be applied in such contestable circumstances, but leave these matters to the AER to determine.

1. Should the Rules specify the form of regulation for prescribed transmission services (as currently) or leave this open for the AER to determine?
2. Are there areas, in addition to those noted above, where the Rules and current regulatory practices differ?

4.3. Alternative Approaches

The application of a building block approach is not the only option for deriving a CPI-X revenue or price cap, and the use of CPI-X incentive regulation is itself not universal. Shortcomings associated with the building block approach may warrant the adoption of an alternative regulatory approach, either across all transmission services or for particular sub-groups of transmission services.[28] Examples of other forms of economic regulation applied to transmission services in a range of international jurisdictions are described in high level terms below. The advantages and disadvantages associated with each of these approaches, as well as with the current building block approach are discussed in chapter 7.

4.3.1. Cost of Service

Traditional cost of service regulation continues to be widely practised in the United States[29] and remains the most common approach in the US for the regulation of electricity transmission services. The essence of this form of regulation is that prices (or revenues) are determined in nominal terms and not for any pre-determined period. Prices are then only adjusted following a further regulatory review, against the principal criteria of the sufficiency of returns and the prudence of investment in assets.

4.3.2. Total Cost Efficiency

Estimates of the total cost efficiency of an individual firm – by such means as least squares regression, Data Envelope Analysis (DEA) or multilateral Total Factor Productivity (TFP) – may be used in place of forward looking cost estimates to determine benchmark efficient revenue or price levels. An assessment of total cost efficiency is then combined with decisions on the appropriate rate of adjustment towards an estimate of efficient costs to determine X in a CPI-X regime. Such approaches have been adopted for transmission

28 Several submissions indicated the need to examine alternatives to the CPI-X building block approach, including Energex, Submission to the Scoping Paper, 19 August 2005, p.3

29 See for example Illinois Power Company, 57 FERC 61,213 at 61,699 (1991)

revenue regulation in the Netherlands[30] and have guided decisions on the setting of transmission price path thresholds in New Zealand.[31]

4.3.3. Productivity Indices

An important variant of the building block approach is the use of productivity indices, such as TFP, to set the X factor in CPI-X price or revenue caps. The appropriate rate of change in prices (or revenues) is set by reference to estimates of the industry-wide long term average rate of total factor productivity growth. The use of industry-wide measures of the rate of productivity growth acts as a substitute for the forward looking estimates of business-specific costs that characterise the building block approach. The starting prices to which CPI-X controls of this form are applied are often – but not always - established by reference to cost building blocks, although with no forward looking element.

Index based forms of regulation have been widely applied to the regulation of both electricity distribution and telecommunications services in the United States.[32] The suitability of TFP based approaches for regulation of electricity distribution services in Australia has been the subject of significant research by, among others, the Utility Regulators Forum[33] and the Victorian Essential Services Commission (ESC).[34] TFP indices have been used to set the price path threshold for transmission services in New Zealand, although the productivity estimates applied were based on those established for distribution businesses.[35]

4.3.4. Price Monitoring

Generally price monitoring does not involve the regulator setting the allowable price. However it can involve the business seeking approval for a proposed price. The essential element is the threat of intervention by the regulator should monitoring disclose conduct, including pricing, which reflects the exercise of market power. The legislative or regulatory framework for a price monitoring regime typically includes qualitative guidance on the principles to be applied in determining or negotiating prices for services. It is generally accompanied by a formal requirement for price and/or cost information to be reported by service providers, and for this to be collated and presented for publication by a regulatory or administrative body.

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30 Dienst uitvoering en Toezicht Energiebeheer (DTe), *Guidelines for price cap regulation in the Dutch electricity sector (network and retail), Period 2000-2003,* 2000

31 Commerce Commission, *Regulation of Electricity Lines Businesses - Targeted Control Regime - Threshold Decisions* (Regulatory Period Beginning 2004), 1 April 2004

32 Application of Southern California Edison to adopt a Performance Based Rate Making Mechanism Effective January 1, 1995, Alternate Order of Commissioners Fessler and Duque, July 21, 1996; and D. Sappington and D. Weisman, *Designing Incentive Regulation for the Telecommunications Industry*, MIT Press 1996

33 Farrier Swier Consulting, Comparison of Building Blocks and Indexed-based Approaches, Utility Regulators Forum, June 2002

34 Pacific Economics Group, *TFP Research of Victoria's Power Distribution Industry*, December 2004; Pacific Economics Group, *Incentive Power and Regulatory Options in Victoria*, May 2005

35 Commerce Commission, *Regulation of Electricity Lines Businesses - Targeted Control Regime - Threshold Decisions* (Regulatory Period Beginning 2004), 1 April 2004

A price monitoring regime operated for electricity transmission services in New Zealand prior to the introduction of the existing threshold and control regime.[36] Airport services in both Australia and New Zealand are currently subject to a price monitoring regime,[37] and the Productivity Commission has recommended it be introduced as a regulatory option for covered gas pipelines.[38]

3. To what extent do the alternative forms of regulation identified above, warrant further investigation and analysis in the course of the Review?
4. Should the Rules provide the flexibility to adopt alternative forms of regulation in appropriate circumstances, and if so, what are those circumstances?
5. Are there any additional forms of regulation that should be considered?

4.4. Relevant Factors in Evaluating Alternative Approaches

Different factors will influence the form of regulation that is appropriate for a particular service. These range from the historical and institutional context in which the form of regulation is to be applied through to the extent of a service provider's market power, and the scope for and importance of achieving future efficiency gains.

Nevertheless, it is possible to identify a range of characteristics that mean some forms of regulation are likely to be more appropriate than others for particular services. In setting out the relevant considerations, it is important to emphasis that the basic case for economic regulation is the likelihood that market outcomes will be improved, as compared with a counterfactual of no regulation, or a different form of regulation.

Importantly, variants of the approaches set out above could to some extent operate alongside each other. For example, a building block or productivity index approach to CPI-X regulation could apply to transmission services for which TNSPs have a high degree of market power at the same time as price monitoring is applied to services which raise fewer market power concerns. The current Rules do provide for such a multi-layered approach to regulation,[39] although actual practice has not adopted that approach. The issue of the appropriate scope of services to which a transmission determination should apply, and the potential for alternative regulatory approaches to be adopted for other services, is discussed in more detail in chapter 5 of this Paper.

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36 See s.52 Commerce Act 1996 (NZ)

37 Treasurer and Minister for Transport & Regional Services, *Joint Press Release: Government Response to the Productivity Commission Report on Price Regulation of Airport Services*, 13 May 2002; Ministry of Economic Development (New Zealand), Control of Airports Advice, 9 May 2003

38 Productivity Commission, Review of the Gas Access Regime, June 2004, Recommendation 8.1, p. LV; The Energy Networks, Submission to the Scoping Paper, 19 August 2005, p.2, suggested that the Productivity Commission's proposed approach be examined in this area.

39 Clause 6.2.3(c), clause 6.2.4(f), National Electricity Rules

4.4.1. Extent of Market Power

The prospect of economic regulation improving on market outcomes arises where a service provider has substantial market power and so will find it both feasible and profitable to raise prices and restrict output, thereby reducing efficiency and harming the interests of consumers. Such inefficiencies have the potential not only to occur in the market for the primary service – in this case, electricity transmission – but also to adversely affect the efficiency of related markets such as those for electricity generation, retailing and transmission alternatives such as demand management and alternative energy supplies.

The greater is the extent of market power, the stronger is the case for regulation to alleviate the problems caused by it. It follows that less intrusive forms of regulation – such as price monitoring - are more likely to be preferred where there are fewer concerns about the extent of market power. The case for moving towards a price monitoring form of regulation for transmission services rests principally on a judgment about the extent of TNSPs' market power.

Relative to more intrusive forms of regulation, price monitoring implies a more significant role for customers in protecting their own interests. Customers are normally better equipped to perform this role when they are fewer in number, are reasonably well informed and have a measure of countervailing power. For example, airports are said to be more suitable for price monitoring because their customers, principally airlines, are well resourced and informed, relatively few in number, and in a position to have some influence over airports' conduct. The appropriateness of a price monitoring regime may therefore depend on the degree of constraint on a service provider's market power that can be imposed by the actions or potential actions of consumers.

Price monitoring forms of regulation can involve substantial information disclosure arrangements. These are designed to make customers better informed about the cost and quality of the services being provided, thereby strengthening their hand in negotiating prices with a service provider. Price monitoring regimes may also be accompanied by some kind of threat that price controls may be introduced or reintroduced. This is designed to strengthen the countervailing power of customers, who have the option of lobbying for regulatory change where information disclosed suggests that a service provider is taking undue advantage of its market power.

6. To what extent does the degree of TNSPs' market power differ for different transmission services? To what extent are transmission customers able to act in a way that constrains the conduct of TNSPs?

7. Would a multi-layered regulatory approach, based on degrees of market power associated with different services, be appropriate?

8. Are there transmission services that are likely to be suitable for a less intrusive form of regulation, such as price monitoring?

4.4.2. Information Asymmetry

A key challenge for all forms of regulation is the existence of asymmetric information. The regulator is not well informed about the regulated businesses' costs and the business usually lacks an incentive to volunteer information to the regulator because that information may be used to its commercial detriment. Incentive regulation therefore seeks to provide regulated businesses with some form of reward (or rent) in order to get it to reveal those costs. This is achieved by allowing a firm to retain a share of the cost reductions in the form of higher profits in the short term in order to ensure continued incentives for efficient service provision in the longer term. Incentive regulation therefore involves a trade-off between maintaining prices in line with costs and preserving incentives for cost efficiency.

Other forms of regulation reflect different priorities. For example, a traditional cost of service approach involving frequent revenue or price cap reviews may be very successful at eliminating excess profits. However, the cost pass through regulatory approach provides little incentive for the regulated business to pursue cost efficiencies and involves a perverse incentive for excessive capital expenditure. In other words, more cost-reflective prices in the short term are achieved at the expense of prices and costs above efficient levels in the longer term.

The existing building block approach to regulation is said to provide incentives for TNSPs to pursue efficiencies and to reveal efficient costs, by decoupling prices from costs for a given period and permitting the TNSP to retain the increased return associated with efficiency gains between regulatory reviews. However, the reliance on forecasts of the TNSP's own costs under this approach compounds the information asymmetry issue and results in regulation that is often characterized as intrusive and information intensive.

The development of forms of regulation involving the use of benchmarks, productivity growth or total cost efficiency, are directed at improving this trade-off. These approaches place less emphasis on the business' own costs and therefore can address the information asymmetry problems. Use of benchmarks and indices may also reduce the administrative and other forms of efficiency loss associated with detailed, cost-based reviews. The suitability of these forms of regulation for electricity transmission will depend upon whether appropriate benchmarks or indices exist, the extent of the market power of the TNSP, the significance of the information asymmetry problem in the transmission industry, and the extent of the potential dynamic efficiency losses from more costly and more intrusive forms of regulation.

9. How significant are information asymmetry problems for electricity transmission regulation?

10. What issues arise under the current building block approach in respect of information asymmetry?

11. To what extent would these be addressed by the adoption of an approach that relied on benchmarks to a greater extent?

4.4.3. Uniqueness of Individual Firm Costs

A frequent criticism of the current building block approach is its reliance on very detailed information relating to an individual TNSP's business, and potentially adverse incentive properties associated with benchmarking the businesses' performance against itself rather than the industry.

Forms of regulation that rely on the use of industry-wide benchmarks have the potential to avoid this criticism. However, the extent to which such approaches are capable of improving the trade-off between maintaining prices in line with costs and preserving long term incentives for efficiency will depend on the extent of diversity of cost structures and market conditions between firms in the industry. The greater the diversity of demand and cost conditions of each firm within an industry, the more important will be firm-specific information in regulating revenues or prices. Conversely, the more uniform are costs, the stronger can be the industry based incentives for efficiency that can be applied to each firm through the use of benchmarking without undue risks that costs and prices will diverge to an unacceptable extent.

For transmission businesses, an important factor in evaluating the scope for, say, productivity based forms of regulation is therefore the predictability and the smoothness of capital expenditure needs, both across businesses and over time. If typical capital expenditure needs vary significantly from one regulatory period to the next, or from one TNSP to another, costs are more likely to vary significantly from the long run trends. In that case, productivity based approaches to determining the X factor in a CPI-X regime based on an industry-wide productivity index may reward one service provider and penalise another, in unintended ways.

A high degree of uniqueness in the cost structures or operating circumstances of individual firms will make it less likely that higher powered or lighter handed forms of regulation will be able to improve the trade-off between rent and efficiency. In fact, offering incentives that are too high powered may worsen the trade-off, suggesting that in situations of greater diversity of industry cost and demand conditions a lower powered form of regulation that pays greater attention to keeping prices in line with costs may be preferred.

12. To what extent are TNSPs faced with demand and cost circumstances that make it relatively easy (or difficult) to make comparisons across businesses, and over time?

4.5. Form of Price Control

With the potential exception of price monitoring, all of the forms of regulation discussed above require some additional arrangement for determining or approving prices (typically annually) within the overall regulatory approach. This is referred to in this Paper as the 'form of price control'. Regulatory regimes can adopt direct controls on individual prices. The discussion in this section focuses on indirect controls.

Different forms of price control can be adopted within each of the forms of regulation discussed above, and will have different incentive properties. The decision on the appropriate form of price control is therefore one that can be expected to have an important effect on outcomes in the market and therefore the achievement of the NEM objective.

4.5.1. Existing Arrangements

The NEL requires the Rules to cover arrangements for the regulation of transmission prices (Schedule 1 item 16). The current Rules are prescriptive in relation to the form of price control for TNSPs and require that the AER set a revenue cap to apply to each TNSP.[40] This requirement is noted in the SRP.[41]

A revenue cap is an indirect form of price control.[42] Under a revenue cap form of price control, expected revenue (calculated on the basis of forecast demand) from the prices charged each year by the TNSP for prescribed services, must be less than or equal to total allowed revenue for the TNSP. The AER currently determines total allowed revenue using the building blocks approach. Specifically the AER calculates the maximum allowed revenue (the MAR) a TNSP can earn in each year. The MAR for the first year of the price control period is expressed as a dollar figure. The MAR for the following years are related to this initial MAR on the basis of CPI-X, ie, $MAR_2=MAR_1*(CPI-X)$ and so on. There is an 'unders and overs' account that operates such that any revenue earned in one year in excess of (that falls short of) the MAR is subtracted from (added to) the MAR applied to prices in the following year.

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40 Clauses 6.2.4(b) and 6.2.3(b), National Electricity Rules. Note that the current drafting of 6.2.3(b) says "*the form of economic regulation to be applied must be revenue capping*". Under the terminology adopted in this Issues Paper, a revenue cap is considered to be a form of price control, rather than a form of regulation.

41 SRP, p.4

42 The discussion in this section relates to the revenue cap under Part B of the current Rules in Chapter 6, rather than the cost allocation provisions in Part D of Chapter 6.

Under the current Rules, adjustments to the MAR beyond those following from the CPI-X formulation are not permitted during the regulatory period. One consequence is that prices cannot be adjusted to reflect contingent investments that are found to be required during the regulatory period, in line with the framework for capital expenditure set out in the SRP (discussed in chapter 7). Instead a retrospective adjustment would need to be made at the start of the following regulatory period.[43]

13. Are there concerns with the current operation of the revenue caps applied to TNSPs? If so, what changes would be appropriate to overcome these problems?

14. Does the fact that the Rules preclude changes to the MAR within the regulatory period present difficulties in relation to the appropriate treatment of capital expenditure?

4.5.2. Alternative Arrangements

Revenue caps are common in regulating transmission businesses around the world. For example, revenue caps apply to the electricity transmission businesses in the UK, Norway and Sweden. However, a revenue cap is only one of the alternative forms of price control that could be adopted in regulating transmission.

One alternative would be a price cap, which is again an indirect control on prices. Under a price cap, prices are approved if they comply with a given formula, related to CPI-X. Different formulae are possible, with one of the most common forms being a tariff basket under which prices are approved if the weighted average of proposed tariffs does not exceed the weighted average of existing tariffs by more than a percentage given by (1+CPI)(1-X). The revenue-based weights used are typically derived from previous quantities sold whilst the X is determined by the overall form of regulation. Price caps are applied to electricity transmission in Singapore and, effectively, in New Zealand. Price caps are also common for electricity distribution in Australia.

In addition to straight revenue caps or price caps, hybrid forms of price control are possible, which combine elements of each.[44] Hybrid controls resemble revenue caps but they also incorporate parameters that allow maximum revenue to vary in line with identified cost drivers (such as increases in demand) or certain events (eg, contingent capital expenditure projects). This type of price control was previously adopted by the Independent Pricing and Regulatory Tribunal (IPART) in regulating electricity distribution businesses in NSW.[45]

The earlier sections of this chapter raised the possibility of different forms of regulation potentially applying to different transmission services. As a result, the forms of price control

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43 ACCC, *NSW and ACT Transmission Network Revenue Cap, TransGrid 2004-05 to 2008-09*, 27 April 2005, p.212

44 The discussion of hybrid price controls in this chapter is distinct from the issue of multi-layered regulatory approaches raised in chapter 4 on the form of regulation.

45 IPART applies a tariff basket form of price control to electricity distribution under its latest determination.

discussed above need not apply across all transmission services. Rather, a multi-layered approach could be employed.[46]

4.5.3. Relevant Factors in Evaluating Alternative Approaches

An issue for this Review is the extent to which the Rules should continue to prescribe the form of direct or indirect price control to be applied to TNSPs, or whether there should be some degree of discretion granted to the AER to determine the form of price control.

The current Rules for electricity transmission are prescriptive, requiring the AER to apply a revenue cap to TNSPs. In contrast, the current Rules for electricity distribution provide guided discretion for the AER, through explicitly permitting a revenue cap, a weighted average price cap or a combination of the two.[47] Similar flexibility is incorporated in the Gas Code (the Code) where the manner in which a reference tariff may vary within an access arrangement period is within the discretion of the service provider, provided that it complies with various factors set out in the Code.[48]

The extent of discretion for the AER to determine the form of price control will need to be consistent with that allowed in relation to the overall form of regulation.

15. Should the Rules continue to be prescriptive in relation to the form of direct or indirect price control to be adopted by the AER for the TNSPs? If so, what form of price control should be prescribed?

16. Alternatively would there be benefit in allowing the AER guided discretion regarding the form of price control? If so what guidance would be appropriate?

To the extent that the Rules do continue to be prescriptive, or to provide at least guided discretion to the AER, rather than unfettered discretion, there is an issue as to the appropriate form of price control for electricity transmission.

Revenue caps are typically seen as having the following characteristics:

- They provide certainty in terms of revenue, however they result in potential profitability risks (both positive and negative) if cost outturns differ from those expected at the time of setting of the MAR. This can be one motivation for adopting a hybrid approach, rather than a straight revenue cap;

- Revenues earned are independent of sales. As a result there is a potential disincentive to expand services. However, to the extent this is considered undesirable, it can be addressed through explicit incentive schemes; and

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46 Consideration of lighter handed regulation for contestable services was raised by EnergyAustralia, Submission to the Scoping Paper, 18 August 2005 p.3

47 Clause 6.10.5(b) National Electricity Rules

48 Gas Code, section 8.3

- There is a need for an unders- and overs- account, which could be seen as increasing complexity.

In contrast, a price cap:

- Allows revenues to change in response to changes in quantities of service provided. This reduces the financial risk faced by the business (provided tariffs are cost reflective);

- Provides positive incentives for efficient tariff structures (eg, Ramsey pricing), which may imply that less regulatory prescription is needed on pricing and businesses can take more responsibility for tariff structure decisions; and

- May affect incentives for demand management, to the extent that revenues depend on volumes sold.[49]

The above are general characteristics only. For electricity transmission, some of these characteristics will be more important than others, and this will influence the choice as to the most appropriate form of price control. For example, the prevalence of fixed costs for electricity transmission may make considerations of revenue variability with respect to quantities less important than for sectors with a higher proportion of variable costs.

There is a close link between the form of price control and the outcomes of the transmission pricing component of the current review. The lower the proportion of revenue that is recovered by means of energy-related tariffs, rather than fixed charges, the closer revenue and price caps become. In addition, the incentives for efficient pricing provided under a price cap will be of little relevance if the Rules for transmission pricing remain relatively prescriptive, as at present. Conversely, the adoption of a price cap may imply the need for less prescription in the Rules for electricity transmission pricing.

17. What characteristics of electricity transmission are relevant in considering the choice of form of price control? Do these characteristics differ from those for electricity distribution where price caps often apply?

18. What factors ought to be taken into account when choosing the form of price control?

19. How do the incentives provided under the different forms of price control impact on the efficient development and operation of the transmission system?

20. What advantages or disadvantages would there be in allowing greater pricing flexibility for TNSPs under a price cap form of price control?

21. What advantages or disadvantages are there in adopting a hybrid form of price control?

[49] Total Environment Centre, Submission to the Scoping Paper 22 August 2005, p. 4

5. Scope of Regulation

The previous chapter discussed the form of regulation, and foreshadowed that a multi-layered approach to the regulation of transmission services could be adopted, with formal price or revenue regulation applying to transmission services which are characterised by substantial market power and a less intrusive regulatory approach being adopted for those services which raise fewer market power concerns. The Rules already provide for such a multi-layered approach, with some transmission services identified as being outside of the scope of the revenue cap.

A key issue for this Review is the scope of transmission services that should fall within the main regulatory control, versus those services where it may be more appropriate to regulate on an alternative basis. This will help to achieve the appropriate incentives for particular transmission services. This is the focus of this chapter.

5.1. Requirement for Regulatory Controls

The NEL provisions that govern this Review provide no specific guidance on the scope of regulation.

Chapter 3 of this Issues Paper briefly discussed the economic preconditions that must be met before regulation is likely to be justified. In summary, regulation is likely to be justified where the loss of economic efficiency due to market power problems is expected to exceed the costs of regulation. This includes the indirect costs of regulation such as the inherent rigidities introduced by regulatory arrangements in the context of a dynamic market and the consequences of incorrect regulatory decisions – commonly known as regulatory failure.

In identifying those services which may fall outside the scope of the main regulatory control, it is important to consider the particular characteristics of services that give rise to market power concerns, and the extent to which these characteristics may apply across different services.

5.2. Existing Arrangements

The scope of services to which a transmission determination made by the AER applies is addressed in the current Rules. The Rules effectively separate transmission services into three categories:

- non-contestable services which are regulated under a revenue cap (referred to as 'prescribed transmission services');
- excluded non-contestable services which fall outside the revenue cap and are determined on the basis of negotiation, with a corresponding mediation and arbitration process; and
- contestable services, which may be subject to a lighter handed form of regulation, at the discretion of the AER.

5.2.1. Services within the Scope of the Revenue Cap

The Rules refer to the services that are regulated under a revenue cap as 'prescribed transmission services'.[50]

In general, prescribed transmission services include all transmission network operating at or over 220kV, or any network operating above 66kV that operates in parallel and provides support to the higher voltage network (ie, above 220kV). The AER also has the option of prescribing any other network assets operating at 66kV to 220kV that it considers ought to be subject to regulation under the revenue cap. In addition to these transmission assets, which cover the vast majority of the transmission system, some connection assets are prescribed, in particular, connection arrangements which have not been subject to a contractual negotiation processes between the TNSP and the connecting party.[51]

These services may have been classified as prescribed services because it was considered that services supplied at those voltage levels are typically supplied under conditions of substantial market power. As noted in chapter 4, more intrusive regulation is more appropriate for services with a substantial level of market power. In the case of prescribed services, the market power is principally determined by economies of scale and externalities. However there may be circumstances where the voltage is not an appropriate indicator of the presence or absence of market power or externalities.

Examples of prescribed services are those which are shared between a number of parties such as transmission lines connecting generators located close together to load centres, interconnectors and lines serving remote non-industrial loads.

22. Is the delineation of those services covered by the main regulatory control set out in the current Rules appropriate? Does this delineation reflect those transmission services with substantial market power?

5.2.2. Services outside the scope of the revenue cap

The current Rules make provision for two distinct categories of service to be treated outside the scope of the main regulatory control - certain excluded non-contestable services and contestable services.

5.2.2.1. Excluded non-contestable services

The Rules specify that some non-contestable transmission services fall outside the operation of the revenue cap. These are:

50 Ch 10 Glossary, National Electricity Rules
51 Clause 6.4.2, National Electricity Rules

- negotiated generator and MNSP access charges;[52]

- that part of a prescribed transmission service which is provided to a standard which is higher or lower than any standard described in schedule 5.1 to the Rules, outlined in the standards published in accordance with clause 6.5.7(b) of the Rules, or required by any regulatory regime administered by the AER;[53] and

- excluded transmission services.[54]

Excluded, non-contestable services may be characterised by:

- a high degree of market power for TNSPs arising from economies of scale;
- the potential to define property rights; and
- users are few, large and well resourced, and so can counteract the market power of the TNSP.

Examples include an increase in network transfer capability in respect of a generator connection point and higher standards of reliability for a particular customer, such as a smelter.

These services are provided on the basis of negotiation, with mediation and arbitration provisions included in the Rules. [55]

In relation to the first of these services, negotiated access charges are levied on generators and MNSPs for specific network investments to facilitate network power transfer capability at the connection point. TNSPs are required to negotiate a connection agreement with access seekers that recovers the costs reasonably incurred in providing such access. In the event negotiations break down, either party may invoke the dispute resolution mechanisms set out in Chapter 8 of the Rules. [56] These involve a two stage process of mediation followed by binding arbitration.

The Commission understands that the arbitration provisions for resolving access disputes have never been invoked.

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52 Clause 6.5.3(b), National Electricity Rules
53 Clause 6.4.3C(b)(5), National Electricity Rules
54 Ch 10, glossary 'Excluded transmission services', National Electricity Rules
55 Ch 10, glossary 'Negotiable service', National Electricity Rules. In addition to the services discussed above which are excluded from the revenue cap, there are other negotiated services that do fall within the revenue cap, such as generator use of system charges.
56 Clause 8.2, National Electricity Rules

23. Are there other transmission services that may be amenable to a negotiate-mediate-arbitrate model of regulation?

24. Are the ‘negotiate–mediate–arbitrate’ arrangements applying to transmission access services operating satisfactorily?

25. Is there an opportunity to improve the efficiency of these arrangements and, if so, what problems need to be addressed?

In relation to the second set of non-contestable services excluded from the price cap, if the TNSP agrees with a user to provide a prescribed transmission service to a higher or lower standard to that set out in the Rules or required by the AER, then the price payable for the service is the price agreed to in accordance with the negotiating framework set out in the Rules.[57] The Commission is not aware of the extent to which this negotiation framework has been used in practice.

26. To what extent do TNSPs provide services on a basis higher or lower than the service standards referenced in the Rules?

27. What issues arise in relation to the negotiation provisions in the Rules for these services?

Excluded transmission services are defined by the Rules[58] as services for which the costs of and revenues for which provision are excluded from the revenue cap applying to prescribed services. The Rules provide no specific guidance on the criteria for a service to be excluded.

The Commission is aware that excluded transmission services were defined in specific jurisdictional instruments applying in South Australia and Victoria.[59] However, these definitions ceased to operate at the time that regulatory control of transmission services passed to the ACCC.[60]

28. Are there currently any services provided by TNSPs that fall under the provisions for ‘excluded transmission services’?

57 Clause 6.5.8(f), National Electricity Rules

58 Ch 10, glossary ‘Excluded transmission services’, National Electricity Rules

59 *Victorian Electricity Supply Industry Tariff Order*, June 1995, clause 3.4 and attachment 5 – part D, *and Electricity Pricing Order of South Australia*, 11 October 1999, Schedule 1(B)

60 *Victorian Electricity Supply Industry Tariff Order*, June 1995, clause 3.6.1(a)(i), *and Electricity Pricing Order of South Australia*, 11 October 1999, clause 1.8(b)(i)

5.2.2.2. **Contestable Services**

The second category of transmission services lying outside the scope of the revenue cap in the current Rules are 'contestable services'.

Contestable services may be characterised by a low degree of market power for TNSPs, as a result of:

- A limited degree of network externality that is not expected to significantly change over time, that is, the service has little impact on the services supplied to other users; and

- Few economies of scale.

Examples of contestable services include generator connection assets (from the generator to the busbar); and a single transmission line connecting a single, remote generator to a shared network.

The current Rules cite competition, and the lighter handed forms of regulation that facilitate competition as desirable objectives in their own right, and specifically state that, *"Concerns over monopoly pricing in respect of transmission services will, wherever possible and practicable, be addressed through the introduction of competition in the provision of transmission services"*.[61]

This objective is given effect through the obligation[62] on the AER to only apply a revenue cap to those services that it considers are not reasonably able to be offered on a contestable basis. The Rules place the responsibility with the AER for determining whether sufficient competition exists to warrant application of a regulatory approach that is more light handed than revenue capping and, if so, the form of that regulation.[63] There is no further guidance in the Rules for the AER in making this determination, other than the general objectives under 6.2.2.

In practice, the Commission is not aware of any formal consideration by the AER as to whether or not any element of currently prescribed services (assets operating at 220kV and above, and deemed assets operating between 66kV and 220kV) are likely to be contestable, and so eligible to be moved outside the revenue cap.

29. Are the current arrangements for defining and separating contestable transmission services satisfactory? In what ways could they be improved? Are there other transmission services that could be treated as contestable?

61 Clause 6.2.3(a), National Electricity Rules
62 Clause 6.2.4(f), National Electricity Rules
63 Clause 6.2.3(c), National Electricity Rules

5.3. Alternative Arrangements

There is a variety of approaches in other relevant jurisdictions to determining the scope of assets or services that are subject to the principal form of regulation, and those for which some degree of contestability means a different form of regulation is appropriate.

For electricity distribution, the Rules[64] provide for the jurisdictional regulator to determine which services should be subject to the principal form of regulation and which should be 'excluded services', and specify a number of principles that jurisdictional regulators are to have regard to in making their determination. For South Australia and Victoria, an initial list of excluded services was explicitly set out in a separate legislative instrument.[65] The jurisdictional regulator has responsibility for determining the form of regulation applying to excluded services.[66]

Under the Gas Code there are two distinct arrangements that address the scope of regulation. The first are the coverage arrangements, which determine when a pipeline is to be subject to regulation.[67] Services offered by non-covered pipelines are not subject to regulation. The second set of arrangements apply to covered pipelines, whereby the service provider is responsible for defining one or more reference services (for which reference tariffs apply) that are likely to be demanded by a significant part of the market.[68] As a result, not all services offered by a covered pipeline fall under the scope of the main regulatory control. Remaining services are covered by the negotiation and arbitration provisions in the Code.[69] The Gas Code therefore provides an example of a multi-layered regulatory approach.

In broad terms, the various alternative approaches involve combinations of:

- establishing principles that govern whether or not services fall inside or outside the scope of the principal regulated activity, with those principles generally administered by a regulator;
- the establishment of a positive list of assets or services that fall either within or outside of the principal regulated activity; and
- defining an alternative form of regulation, most often in the form of price monitoring and/or a negotiate-arbitrate arrangement, that applies to services outside the principal regulated activity but which nevertheless involve a sufficient degree of market power to warrant some form of regulatory oversight.

Relevant considerations in evaluating the various alternative approaches to defining the scope (and form) of regulation are discussed below.

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64 Clause 6.10.4(a), National Electricity Rules

65 South Australia EPO Schedule 2(B): Excluded Distribution Services; Victorian Electricity Supply Industry Tariff Order, clause 5.7. These provisions have now expired.

66 Clause 6.10.4(b), National Electricity Rules

67 Clause 1, Gas Code

68 Clauses 3.2(a)(i), Gas Code

69 Clauses 5 and 6, Gas Code

5.4. Relevant Factors in Evaluating Alternative Approaches

To help identify which transmission services should be within the scope of the main regulatory control, and which services may be suitable for an alternative regulatory treatment, or even no regulation, it is necessary to identify the attributes of particular services that may give rise to market power problems. In general the greater the extent of market power of the service provider and the more likely it is that the NEM objective would be best met by regulation.

In terms of transmission the two most important economic barriers are:

- Substantial economies of scale - this describes the situation where the unit costs of providing a service by a single producer falls over a wide range of output; and

- Network externalities - the development and operation of one part of the transmission system affects the capacity and value in another part in complex in ways that are difficult to predict. These complex externalities frustrate the efficient provision of transmission services by the market.

In practice, there will generally be no bright line to determine where the boundary should be drawn between services that are regulated under the main regulatory control and services regulated outside of that control, or not regulated at all.

30. Are the current arrangements in the Rules for identifying and classifying different elements of transmission service as prescribed, excluded and contestable appropriate? What potential improvements could be made?

31. To what extent is there scope for any element of the existing set of prescribed services to be provided on an excluded or contestable basis, thereby reducing the scope of the current revenue capped services? What services would these be?

32. Are there any elements of existing transmission services not presently included as prescribed services that should be brought within that definition?

33. Should the services to be included within the scope of the main regulatory control be set out in the Rules or left to the discretion of the AER? If the latter, what is the extent of appropriate guidance in the Rules as to the principles that the AER should adopt in making this determination?

34. Who is the appropriate body to determine the potential contestability of services? What guidance (if any) should be set out in the Rules on the principles to be adopted in such an assessment?

35. Who is the appropriate body to determine the form(s) of regulation for services falling outside of the main regulatory control? What guidance (if any) should the Rules provide on the form of this regulation?

6. Performance Obligations and Incentives

As discussed in chapters 3 and 5, two key purposes of regulating transmission services are to constrain the market power of TNSPs (to the extent it arises), and to promote efficient investment and operating behaviour, for the long term benefit of customers. Economic regulation may be an appropriate means of preventing TNSPs earning monopoly profits. However, depending on the precise form of regulation adopted, it may also provide financial incentives for TNSPs to under- or over-invest or operate their networks inefficiently, with negative implications for network performance or service levels[70].

Network and service performance standards are ultimately a function of capital investment and operating performance. Consequently, regulation may be necessary to ensure investments are made and levels of operating performance are such that service delivery and quality is maintained at levels that are in the long term interests of customers. That regulation may be in the form of express performance obligations or economic regulation which seeks to 'incentivise' desired investment and performance outcomes or both.

To help ensure network performance remains acceptable, TNSPs are currently subject to a variety of express performance obligations in the Rules and jurisdictional instruments, covering issues such as:

- under Chapter 5 of the Rules, network reliability and frequency, voltage and stability requirements (with or without the occurrence of credible contingency events);
- also under Chapter 5, good faith negotiating requirements for connection agreements and service provision at particular transmission connection points;
- through the Annual Planning Review, information provision regarding:
    - forecast loads;
    - connection point developments;
    - network constraints and performance shortfalls; and
    - the TNSP's proposed solutions to these, including consideration of non-network alternatives; and
- through other Rule provisions, information provision on planned network outages.

Some of these obligations are supported by civil penalty provisions in the NEL Regulations. However, the quantum of civil penalties may not reflect the value network users place on satisfaction of these obligations. Moreover, not all performance obligations in the Rules are

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70 Focusing on the implication of regulatory approach on service standards was raised in several submissions, including Energy Intensive Industries Alliance, 19 August 2005, p.2

appropriate for civil penalty sanctions. It is likely to be costly for TNSPs to comply with performance obligations. If purely motivated by profit, TNSPs may not find it financially worthwhile to achieve compliance with these obligations in the absence of rewards (or penalties) reflecting the value of good (or poor) performance to network users. TNSPs may still seek to satisfy these jurisdictional licence obligations in order to remain lawful participants or maintain their reputations with stakeholders.

In addition, many of the network performance obligations in the Rules and jurisdictional instruments are only capable of discrete compliance or non-compliance and the division between the two may not be clear cut. This means that even if penalties were imposed for non-compliance, these obligations may not be capable of providing incentives for standards of network performance beyond the stipulated minimum, even though such improvements may be highly valued by network users and consumers.

Further, the existence of express performance obligations which attract penalties for non-compliance alone, will not provide an incentive to service providers to achieve compliance at the least long run cost. Put simply, regulatory obligations which mandate service performance levels may merely mean those performance levels are achieved at inflated cost.

Therefore, there may be a role for economic regulation to supplement and reinforce express performance obligations by providing financial incentives for the efficient delivery of desired investment and performance outcomes.

Chapter 4 discussed the broad incentive properties of different forms of regulation, such as building block, cost of service, TFP and price monitoring. The focus of this chapter is more specific. It seeks to highlight the key aspects of the existing and potential alternative regulatory arrangements that deal with, or have implications for, TNSPs' incentives to efficiently achieve desired levels of investment and service performance.

Chapter 7 contains a more detailed discussion of the incentives arising from regulatory arrangements for determining TNSPs' regulatory cost components and revenue requirements.

6.1. NEL Requirements

The NEL recognises the importance of developing a regulatory regime that contains incentives for greater efficiency.

Section 35 and Schedule 1 of the NEL require the AEMC to develop Rules in relation to the economic regulation of transmission systems. Amongst other things, the Rules must provide effective incentives to transmission operators to promote economic efficiency in the provision of transmission services, including:

- making efficient investments; and
- the efficient provision of services.

Item 23 of Schedule 1 makes special reference to "*incentives for regulated transmission system operators to make efficient operating and investment decisions*."

6.2. Existing Arrangements

6.2.1. Network Performance

As discussed above, the existing Rules and jurisdictional instruments generally impose absolute performance obligations on TNSPs in relation to network reliability, negotiation of new connections and informational provision. Despite the existence of these obligations, there have been concerns since the start of the NEM that TNSPs may not be incentivised to operate networks efficiently and to operate in a manner which is aligned to the efficient operation of the wholesale and retail markets.[71]

Although the Rules and jurisdictional instruments impose express obligations on TNSPs to provide reliable supply to consumers, there are no similar requirements for standards of network service to generators, except those (few or non-existent) negotiated through connection agreements.

In applying the economic regulation under the current Rules the ACCC has developed financial incentives for more efficient network performance standards.

In its service standard guidelines, the ACCC sought to develop a framework for service incentive schemes to apply to each TNSP. This framework set up TNSP service standards in a number of areas, for example:

- transmission circuit availability by:
    - importance of circuit (critical and non-critical); and
    - time (peak and intermediate); and
- outage duration, to the extent data on a TNSP's historical performance was available.

These standards are then linked to an incentive scheme that places up to +/- 1% of the TNSP's regulated revenue at risk depending on its actual performance against the standards.[72] A service performance incentive scheme was applied to TransGrid in its recent regulatory review.[73]

However, the network performance standards adopted by the ACCC are general in nature, rather than being targeted at particular categories of users, such as retailers/consumers and generators.

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71 Some submissions have raised the need to ensure that the incentive regime for TNSPs is aligned with market need such as the NGF, 19 August 2005, p. 5

72 Service standards guidelines, p.10

73 TransGrid decision, pp.162-175

The current service standards regime appears primarily designed to promote efficient timing (ie, off-peak), and minimise the duration, of planned outages. The ACCC stopped short of developing market linked performance measures, such as linking a TNSP's revenue to the impact of its operating behaviour on market outcomes. The ACCC concluded that there were difficulties in establishing whether TNSP behaviour caused the relevant market outcome (or was just coincidental or consequential) and in valuing the TNSP's market impact.[74] The ACCC also raised the practical issue of determining what share of TNSPs' revenues should be linked to market outcomes, given that market impacts are sometimes large relative to regulated revenues.[75]

Notwithstanding these difficulties a question for this Review is what, if any, aspects of economic regulation under Chapter 6 of the Rules should seek to give TNSP's incentives to take into account the potential market impact of their operating decisions. For example, should the regulatory framework provide an incentive to TNSP's to schedule maintenance projects which may take major network elements out of service during periods of lower demand or to schedule maintenance projects which will significantly improve the efficient operation of the wholesale market in a timely manner.

36. What role should there be for economic regulation under Chapter 6 of the Rules to reinforce or supplement express network or service performance obligations?

37. What service performance measures should be targeted? Should they be general in nature or targeted at different categories of network users? Should they be based on technical measures of availability and outages (as at present) or market impacts? Precisely what measures would be most appropriate to promote the NEM objective?

38. How should target performance levels be set? If market impact measures are proposed, how should the difficulties surrounding the identification of TNSPs' roles in causing market impacts and the measuring of market impacts be addressed?

39. How should achievement or non-achievement of performance levels be linked to TNSPs' regulated remuneration?

40. What share of a TNSP's regulated remuneration should be at risk through service performance incentive schemes?

6.2.2. Capital Expenditure

TNSPs can achieve higher levels of network performance in part through investment in their networks. However, to the extent TNSPs are entitled to recover such expenditure from network users, TNSPs may have incentives to over-invest or otherwise make poor investment decisions at the expense of the NEM objective. This means it may be appropriate for the regulatory arrangements to consider incentives for efficient capital

74 Service standards guidelines, pp.8-9
75 Service standards guidelines, p.9

expenditure (and operating expenditure – see below) alongside incentives for meeting and exceeding network performance obligations.

6.2.2.1. The current Rules

Chapter 5 of the existing Rules make TNSPs largely responsible for network planning and investment decisions, including the application of the Regulatory Test to proposed investments. As part of these responsibilities, TNSPs are required to inform the market of forecast network constraints and reliability shortfalls and consult with stakeholders on proposed augmentations and potential non-network alternatives.[76] These regulatory obligations to provide the market with information of this character and obliging TNSPs to consider both network and non-network solutions to forecast constraints and reliability shortfalls, are intended to ensure that only efficient investments in transmission networks are undertaken.

Consistent with this objective the Rules provide for regulated funding of generation options where these are the most efficient solution to a perceived need for network augmentation. However, the Rules do not explicitly provide such funding for demand management or non-electricity options.[77] It is also not clear how well funding for generation options has worked in practice.

The Rules allow parties to dispute the analysis of the TNSP, including the Regulatory Test analysis and consideration of transmission alternatives.[78] However, the Rules prevent disputes about whether proposed large reliability investments satisfy the Regulatory Test going to the AER for resolution.[79] Further, for small network investments, there is no scope prior to commitment to raise disputes about their assessment to an independent body. This suggests that, for all but large non-reliability investments, the Rules would appear to impose few pre-investment checks on TNSPs to ensure they plan and invest efficiently and consider the widest range of alternatives to meet the desired outcomes.

Where TNSPs have a substantial degree of market power there is not only the risk of inefficient over-investment in transmission networks but also the risk of inefficient under-investment. The Rules do not currently contain any mechanisms whereby TNSPs can be directly obliged to carry out particular investments. Where TNSPs are not subject to regulatory mechanisms which directly oblige them to carry out particular investments in circumstances where those investments may be efficient from a customer's perspective, there may be a case for allowing customers to directly invest in network assets.

However, while the Rules provide for funded augmentations, they do not legally oblige TNSPs to undertake network investments that transmission customers are willing to fund.

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76 Clause 5.6.2A, National Electricity Rules

77 Clause 5.6.2(m), National Electricity Rules; this was noted in Total Environment Centre, Submission to the AEMC Scoping Paper, 22 August 2005, pp.4-6

78 Clauses 5.6.6 and 5.6.6A, National Electricity Rules

79 See clause 5.6.6(l), National Electricity Rules. 'Large' presently means an investment greater than $10 million but the threshold is within the control of the AER. What is a 'reliability augmentation' to be determined according to guidelines developed by the Inter-regional Planning Committee and this may be assessed by the Dispute Resolution Panel.

They also do not confer rights to other parties to develop transmission investments within a TNSP's network.

As with the network performance obligations in Chapter 5, the Rules provide only limited financial penalties for TNSPs for failure to undertake their information provision and planning roles appropriately. The Regulations impose civil penalties for breach of some provisions, but once again, there is no clear link between the value of prescribed penalties and the value to users of compliant performance and there is no reward for performance greater than the stipulated minimum in these areas.

With respect to incentives for efficient investment, Chapter 6 of the existing Rules does impose a number of requirements. For example:

- clause 6.2.2 requires the AER to develop:
    - an incentive-based regulatory regime that provides a fair and reasonable return on efficient investment; and
    - a regulatory regime that fosters efficient investment in transmission and upstream and downstream activities;
- clause 6.2.3 requires that the regulatory regime provides TNSPs with:
    - incentives to increase efficiency; and
    - provides a fair and reasonable rate of return on efficient investment based on various rules for asset valuation, including the need to initially adopt jurisdictional regulatory asset values and to subsequently determine an appropriate valuation methodology having regard to a preference for a deprival approach;
- clause 6.2.4 requires the AER, in setting a revenue cap, to have regard for:
    - the potential for efficiency gains in capital costs; and
    - the provision of a fair and reasonable return on efficient investment including sunk assets, subject to the above requirements for valuing sunk assets.

The regulatory treatment of capital expenditure in general is considered in detail in chapter 7.

41. What role, if any, should Rules for economic regulation have in providing incentives for TNSPs to avoid inefficient over-or under-investment in network assets?

42. Are economic incentives necessary to ensure TNSPs provide the market with information about forecast constraints and reliability shortfalls?

43. Are economic incentives necessary to ensure TNSPs consider both network and non-network solutions (including demand management and other energy sources) to forecast constraints and reliability shortfalls? How could such incentives operate?

44. Are Rules or incentives necessary and appropriate to require TNSPs to undertake funded augmentations, or to require TNSPs to allow other parties to develop transmission assets to connect to TNSPs' networks?

6.2.2.2. **Treatment of the regulatory asset base**

The operation of economic regulation itself can provide both intended and unintended incentives for inefficient network investment decisions by TNSPs. Network investments may become 'stranded' over time either as a consequence of changing demand and supply conditions (market stranding) or because of regulatory decision making (regulatory stranding). How economic regulation deals with the issue of economic and regulatory stranding of assets can provide intended and unintended incentives around investment decisions. On the one hand the risk of stranding may increase the incentives experienced by the TNSP to ensure it only undertakes efficient investments. On the other hand, the risk of stranding may have an overall chilling effect on investments.

In the DRP[80], the ACCC took the view that there were advantages to periodic revaluation of the regulatory asset base (RAB) at each regulatory review. Although acknowledging the uncertainty this would involve for network investment, the ACCC argued that the threat of *ex post* optimisation would provide market-like incentives to TNSPs to undertake efficient investment and asset management decisions.[81]

In the SRP, the ACCC stated a preference for a lock-in approach in which the value of the RAB is not periodically revalued but is rolled forward, on the basis that this would minimise investment uncertainty for TNSPs and thereby improve TNSPs' incentives to invest efficiently.[82] However, the SRP states that the AER is not necessarily bound to adopt this approach in every case and the current Rules may not be consistent with the proposed lock in approach.

The regulatory treatment of the asset base in general is considered in detail in chapter 7.

80 ACCC, *Draft statement of principles for the regulation of transmission revenues*, 27 May 1999
81 DRP, pp.52, 55-56
82 SRP background paper, pp.37-39

45. How significant is the difference between a periodic revaluation and lock-in approach to the RAB in terms of incentivising efficient investment and asset management behaviour by TNSPs?

46. What are the implications of a lock-in approach to the RAB for the development, content and application of other incentive schemes targeted at capital expenditure, operating expenditure and network performance?

6.2.2.3. **Return on and of capital expenditure**

The manner of operation of economic regulation itself can provide both intended and unintended incentives for inefficient network investment decisions by TNSPs. The particular manner in which or process by which the form of economic regulation permits the TNSP to receive a return on and of capital expenditure can have important incentive properties.

In the DRP, the ACCC had adopted an *ex post* approach to the assessment of capital expenditure, in which the ACCC could write down (after the fact) the value of investment deemed imprudent.

In developing the SRP, the ACCC changed to an *ex ante* approach to assessing the value of capital investment to be subject to a capped level of expenditure. The *ex ante* approach provides symmetrical or low powered incentives whereby the TNSP earns the return on, and return of, capital on the cap level of expenditure for a period, even if actual expenditure is below (or above) the cap level.

The ACCC's stated intention of moving to an *ex ante* approach for capital expenditure was to promote investment certainty.[83] The *ex ante* arrangements were designed to create some incentives for efficient capital expenditure without excessively penalising TNSPs for overspending the *ex ante* cap on investment that was efficient.[84] This differs from the asymmetric or high powered incentives proposed in the draft SRP.

Another part of the ACCC's rationale for the low powered incentive approach was to promote consistency with incentives for service quality and operating expenditure.[85]

The SRP stated that the *ex ante* approach would not involve pre-approval of specific projects: TNSPs would be free to invest in whatever suite of projects they wished,[86] although in the TransGrid decision, the ACCC did go through proposed projects for the *ex ante* cap in considerable detail. In addition, the SRP stated that TNSPs would be required to provide

83 SRP background paper, p.47.
84 SRP background paper, pp.52-53.
85 SRP background paper, p.53.
86 SRP background paper, pp.55, 62.

comparisons between actual capital expenditure and the forecasts used in the revenue cap decision and provide an explanation for any variances between the two.[87]

The SRP background paper also reiterated that the current provisions of the Rules apply to all capital expenditure and that "*compliance with the requirements of the Rules (including, where relevant, the application of the regulatory test) will be a pre-condition for the inclusion of actual expenditure in the closing RAB.*" [88]

In addition, the SRP also allows for a separate excluded (now referred to as contingent projects) cap for larger and more unpredictable projects, with a similar incentive scheme as for *ex ante* cap expenditure. Chapter 7 discusses the determination of the *ex ante* and contingent projects caps in more detail.

Finally, the SRP background paper dealt with conditions under which a TNSP's revenue cap could be re-opened. Broadly speaking, the TNSP could propose a re-opening to deal with events that materially adversely affected the TNSP and could not have been contemplated by the TNSP at the time the original revenue decision was made.

A number of issues arise with the *ex ante* approach in the SRP.

The low powered incentives under the SRP's *ex ante* cap regime imply that even if TNSPs overspend the cap on investment that is efficient, they will effectively be penalised by not being able to recover their full return on, and return of, the excess expenditure during the regulatory period. In addition, the provisions governing contingent projects do not address the scenario where a contingent project is not identified during a regulatory review but the need for it emerges later.

47. How do *ex ante* and *ex post* capital assessment regimes (as formulated in the DRP and SRP) affect TNSP incentives to only engage in efficient investments?

48. What are the practical and administrative strengths and weaknesses of *ex ante* and *ex post* capital assessment regimes?

49. If TNSP investment programmes should be subject to *ex ante* assessment should low or high powered incentives for expenditure be adopted and if so why? Is there a risk with either approach that investments that would otherwise be efficient may not be undertaken at the appropriate time? Under an *ex ante* regime, if TNSPs are not penalised for exceeding capital caps how should the risk of inefficient investments be managed?

50. Should regulatory determinations be capable of being reopened to incorporate the cost of specific and unforseen capital projects into any existing revenue or price caps? Where regulatory determinations can be reopened in this way, is the overall risk of inefficient investments increased and if so how can that be managed?

[87] SRP, p. 19
[88] SRP background paper, p. 55

51. What are the respective implications of an *ex ante* or an *ex post* approach to the regulatory assessment of capital investments for the development, content and application of other incentive schemes targeted at operating expenditure and network performance?

6.2.3. Operating Expenditure

As with capital expenditure, TNSPs can achieve higher levels of network performance through increased operating expenditure and/or undertaking that expenditure more efficiently. Therefore, it may be appropriate for the regulatory arrangements to consider incentives for efficient operating expenditure alongside incentives for higher network performance and efficient capital expenditure.

6.2.3.1. The current Rules

Many of the provisions in the existing Rules concerning incentives for efficient capital expenditure apply to operating expenditure. For example:

- Clause 6.2.2 requires the AER to develop a regulatory regime that fosters efficient operating and maintenance practices;
- Clause 6.2.3(d) requires the AER's regulatory regime to provide incentives and reasonable opportunities to increase efficiency; and
- Clause 6.2.4(c)(3) requires revenue caps set by the AER to have regard for the potential for efficiency gains in operating and maintenance costs.

6.2.3.2. Regulatory practice

The ACCC's revenue cap determinations generally allowed TNSPs to share the benefits of any operating expenditure reductions below target levels for a period of time. However, the mechanism for benefit sharing has changed more recently from a smoothing mechanism (a glide path) approach to an efficiency carryover approach under the SRP. The former was based on taking the difference between forecast and actual expenditure for a particular year and basing benefit sharing for the next regulatory period on that difference. An efficiency carryover allows the TNSP to get the benefit (or loss) from underspend (or overspend) for a rolling five year period.

With respect to levels of prescription, generally speaking, there is a potential trade-off between increasing certainty through the provision of more detailed guidance in the Rules, and a reduction in the flexibility required at an operational level to adopt the most appropriate arrangements in a specific case.

Other aspects of the regulatory treatment of operating expenditure are considered in detail in Chapter 7.

52. Should the regulatory arrangements allow TNSPs to retain some share of operating expenditure reductions below target levels into the next regulatory period in order to provide an incentive to incur only efficient operating expenditure? If so, how should those arrangements operate? Is an efficiency carryover arrangement a better way to provide incentives for reducing operational expenditure than a glide-path or other approach?

53. To what extent should the Rules provide guidance on the operational expenditure incentive arrangements to be adopted by the AER?

6.3. Alternative Arrangements

6.3.1. Network Performance

As discussed above, the ACCC has developed a framework for incentive schemes around transmission service standards. Incentives for service quality may be even more important in an environment where there is no periodic revaluation of the RAB and no *ex post* assessment of capital expenditure to help ensure investment undertaken is efficient.

There are several other service incentive arrangements in place around the NEM. For example, SPI PowerNet has a separate availability incentive scheme worth +/- 2% of its regulated revenue in its network agreement with VENCorp that, according to VENCorp, provides for "*time sculpted availability rebates for each network element based on its importance to the Victorian transmission network*"[89]. However, this scheme too does not base rebates on *actual* market impacts. The ESC has applied an S-factor incentive scheme for Victorian distributors since 2001, based around financial incentives for service performance along similar lines to the ACCC's incentive regime.[90]

Notably, neither the ACCC nor the VENCorp or ESC schemes involve incentives for firmer access to specific loads or generators as such. All the schemes refer to either the availability of specific transmission elements or the overall delivery of power through the network. An issue for the present review is whether the Rules should seek to promote firmer access for particular categories of network users.

Perhaps the most comprehensive transmission incentive scheme in place around the world is the Office of Gas and Electricity Market's (Ofgem) system operator scheme covering the National Grid Company (NGC) in Britain. This scheme provides incentives based on NGC's cost performance in a number of areas, such as transmission uplift (including frequency response, reserve, transmission constraints, black start procurement), transmission losses and balancing mechanism costs[91]. Importantly, the scheme has until now been based

[89] VENCorp, *Electricity Transmission Use of System Prices, 1 July 2005 to 30 June 2006*, 13 May 2005, p.5

[90] ESC, *Electricity Distribution Price Review 2006-10, Draft Decision*, June 2005, p.81

[91] The balancing mechanism is Britain's replacement for the England and Wales Pool that operated until it was replaced by the New Electricity Trading Arrangements (NETA) in 2001

on the cost of operating the power system. Ofgem is presently considering how it could be extended to promote more efficient development of the transmission system.[92]

The NGC schemes have been very successful in reducing system operation costs, with transmission uplift falling from £508m per anum in 1993/4 (in £1999) to £211m per annum in 1998/9[93] and the overall annual cost of system operation falling by more than £400m between April 1994 and March 2001[94]. There have been further reductions since the start of New Electricity Trading Arrangements (NETA) in March 2001.[95]

Such cost reductions make the idea of applying a similar scheme for the NEM appear attractive. However, the NGC scheme covers a range of activities that fall within NGC's responsibilities as system operator, rather than as transmission operator. For example, in the NEM it is NEMMCO, not TNSPs, that develops constraint equations, decides when lines need to be de-rated for system security purposes and manages black start procurement. The provision and dispatch of frequency control ancillary services in also managed by NEMMCO through eight separate markets. In Britain, NGC is responsible for all of these tasks. While some similar incentive arrangements for TNSPs in the NEM may be possible, complete emulation of the arrangements in Britain would be likely to require large scale institutional change in the NEM, which is not being contemplated.

NGC is also subject to a new reliability incentive schemes, following the London blackout of 2003. This scheme provides a reward of up to 1% and a penalty of up 1.5% of NGC's revenues depending on the level of energy unsupplied from the grid in a given year.[96]

54. Is the current institutional design of the NEM amenable to a broader service- or performance outcome-based incentive regime than those currently instituted by the AER? If so, what particular outcomes should be targeted?

55. How should consistency between service performance, capital expenditure and operating expenditure incentive regimes be achieved and maintained?

56. To what extent should the service performance incentive regimes be prescribed in the Rules?

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92 Ofgem, *NGC system operator incentive scheme from April 2004, Initial consultation document,* December 2003, pp.5-7

93 Ofgem, *NGC Incentive Schemes from April 2000, Transmission Services Uplift and Reactive Power Uplift Schemes, A Decision Document,* February 2000, pp. 13-14, especially Table 2.1

94 Ofgem, *NGC system operator incentive scheme from April 2004, Initial consultation document,* December 2003, p.19

95 *Ibid*

96 Ofgem, *Electricity transmission network reliability incentive schemes, Final proposals*, December 2004, pp.13-17

6.3.2. Capital Expenditure

6.3.2.1. Treatment of the RAB

Under the Gas Code, there is a general requirement that the initial capital base at the time a new access arrangement is approved is the capital base applying at the expiry of the previous access arrangement, adjusted to account for new facilities investment, depreciation and redundant capital (ie, a roll forward approach).[97] The Gas Code also allows for redundant assets to be written down for the purposes of setting future tariffs and obliges the regulator to consider the uncertainty a capital redundancy policy would create and its effect on the service provider and actual and potential users before approving such a policy.[98] The GasNet access undertaking incorporates the scope for removing redundant assets from the RAB.[99]

By contrast, the regulatory arrangements for electricity distribution assets in Victoria and South Australia provide for a roll forward approach with no periodic revaluation.[100]

57. Should issues of consistency between the regulatory arrangements for electricity transmission and gas transmission or between electricity transmission and electricity distribution be a consideration in making Rules for the regulatory treatment of the RAB?

6.3.2.2. Return on and of capital expenditure

The Gas Code provides for both *ex ante* and *ex post* assessment of capital expenditure. Generally speaking, the Gas Code works on the basis of *ex post* review prior to inclusion of that expenditure in the RAB.[101] Clause 8.16(a) provides that the cost base may be increased by the amount of actual new facilities investment in the preceding regulatory period, provided that 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 sustainable cost of delivering Services*."[102] The GasNet access arrangement incorporates *ex post* assessment of new facilities investment prior to inclusion in the RAB.[103]

However, clause 8.16(b) allows for the capital base to be increased by the amount of *proposed* new facilities investment where the regulator has agreed, in its discretion, that the investment

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97 Clause 8.14, Gas Code

98 Clause 8.27, Gas Code

99 ACCC, *GasNet Australia access arrangement revisions for the Principal Transmission System, Final Decision,* 13 November 2002, section 4.3, pp.68-70

100 Victorian Electricity Supply Industry Tariff Order, 5.10(b); South Australia Electricity Pricing Order, section 7.2(e) and Schedule 9

101 Clauses 8.15-8.16, Gas Code

102 Clause 8.16, Gas Code

103 ACCC, *GasNet Australia access arrangement revisions for the Principal Transmission System, Final Decision,* 13 November 2002, section 4.3, p.63

would meet the prudency criterion. Such a decision is binding on the regulator at future reviews.[104]

Capital expenditure benefit sharing regimes vary according to jurisdiction and industry. In its 2004 distribution price control, Ofgem applied the roller mechanism[105] to capital expenditure after deciding it was not suitable for operating expenditure (see below). In Victoria, the ESC is proposing to remove the efficiency carryover regime applying to capital expenditure for the 2006-10 regulatory period due to the unstable nature of capital expenditures.[106]

The GasNet access undertaking provides for no efficiency carryover due to the lumpy and irregular nature of capital expenditure in gas transmission pipelines.[107] The Victorian gas distribution access undertakings do provide for a five year efficiency carryover, but only with respect to return on forecast capital expenditure, not in relation to depreciation.[108]

58. Do issues of consistency between the regulatory arrangements for electricity transmission and gas transmission or between electricity transmission and electricity distribution affect the appropriate regulatory treatment of the return on and of capital expenditure?

59. If TNSP specific investment programmes should be subject to *ex post* assessment, should there be a mechanism for TNSPs to approach the regulator in advance of particular capital projects in order to get regulatory certainty as to the way in which the investment will be treated prior to undertaking it?

6.3.3. Operating expenditure

The main options for operating expenditure incentive schemes revolve around the form of benefit sharing. The Tariff Order in Victoria requires the regulator to have regard to ensuring a fair sharing of benefits achieved through efficiency gains between customers and distributors.[109] The ESC's recent Draft Determination on the Victorian electricity distribution businesses incorporated an efficiency carryover of underspend and overspend,[110] while Ofgem did not apply a similar roller mechanism in its 2004 distribution price control due to concerns about the inappropriate capitalisation of operating expenditure.[111] The Electricity Pricing Order (EPO) in South Australia has a similar requirement to the Victorian

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104 Clause 8.21, Gas Code

105 Ofgem, *Transmission price control review, Initial consultation*, July 2005, p.30. See Appendix 3 for further details on the roller mechanism.

106 ESC, *Electricity Distribution Price Review 2006-10, Draft Decision*, June 2005, p.351

107 ACCC, *GasNet Australia access arrangement revisions for the Principal Transmission System, Final Decision,* 13 November 2002, section 10.1.7, pp.265 and 282

108 See, for example, TXU Networks, *Part B of the access arrangement by TXU Networks (Gas) Pty Ltd for the distribution system, Reference tariffs and reference tariff policy*, 1 January 2003, clause 6.4, p.23

109 Victorian Electricity Supply Industry Tariff Order, 5.10(d)(ii)

110 ESC, *Electricity Distribution Price Review 2006-10, Draft Decision*, June 2005, pp.348-9

111 Ofgem, *Transmission price control review, Initial consultation*, July 2005, p.30

Tariff Order but goes further in saying that the regulator is to have regard to the need to offer the distributor a continuous incentive (ie, equal in each year of the regulatory period) to improve efficiency and to consider rewarding the business for efficiency gains, particularly where these result from management initiatives.[112] In both jurisdictions, the regulator has adopted efficiency carryover mechanisms of the same form as that set out in the SRP. However the formula for the carryover is not set out in the underlying regulatory instrument.

The Gas Code contains a number of provisions in relation to incentive mechanisms.[113] These provisions specify the general principle underlying such a mechanism and set out the objectives that such a mechanism should be designed to achieve.[114] The Gas Code provides a non-exhaustive list of examples of incentive mechanisms. The ESC in Victoria has approved an efficiency carryover arrangement for operating expenditure for gas distributors. GasNet also operates under a similar incentive mechanism. Again, the details of the mechanism are not prescribed in the Gas Code.

In terms of the form of incentive mechanism adopted, there are potential alternatives to the efficiency carryover approach, including a glide path as adopted by the ACCC in its determinations for ElectraNet and SPI PowerNet.

60. Do alternative arrangements provide any guidance as to the appropriate form of operational expenditure incentives for transmission in the NEM?

112 South Australian Electricity Pricing Order, 7.2(h)

113 Clauses 8.4.4 – 8.46 Gas Code

114 ie, the service provider should be permitted to retain all (or a share) of any returns from the sale of a reference service that exceed the returns expected at the start of the reference period, particularly where the additional returns are attributable (at least in part) to the efforts of a service provider.

7. Approach to Determining Cost Components

The NEL requires the Rules to be developed by the AEMC to cover asset valuation, a depreciation allowance, operating costs and an allowable rate of return.[115] It also requires the Rules to provide incentives for transmission system operators to make efficient operating and investment decisions.[116] Again this comes back to the key themes of ensuring that the long term incentives of end-users and participants are aligned.

This chapter sets out the issues arising in relation to determining each of the cost elements forming part of the determination of regulated transmission revenues. It is important to recognise that the approach to defining, reporting and applying these cost components needs to be addressed under any of the options for the form of regulation discussed in chapter 4, not only the building block approach. For example,

- TFP and benchmarking-based approaches need cost information to derive TFP/efficiency estimates and to set an appropriate P_0[117]; and

- a price monitoring regime would likely need to monitor costs (defined in the same manner as would apply under a regulatory control regime), as well as prices and revenues, in order to assess whether prices were within an acceptable range.

The Rules in relation to each of the cost components will need to be drafted in a manner that is consistent with the Rules in relation to the form of regulation. The discussion of each of the main cost components in the remainder of this chapter is not intended to preclude the adoption of any of the forms of regulation discussed in chapter 4 (or any alternative forms proposed by submissions). Submissions are invited commenting on each of the cost components in so far as they are relevant to the submitters preferred form of regulation.

7.1. Opening Asset Base

7.1.1. Existing Arrangements

The current Rules provide a relatively wide degree of discretion for the AER in determining the opening asset base. Importantly, the current Rules allow for the subsequent revaluation of assets, once they have entered the asset base.

Specifically the current Rules (clause 6.2.3(4)) require that:

- assets created under a take or pay contract are valued in a manner consistent with that contract;

115 Schedule 1, items 21 to 22, NEL
116 Schedule 1, item 23, NEL
117 P_0 refers to the prices approved for the first year of the regulatory control period.

- assets in service as on 1 July 1999 are valued at the value determined by the Jurisdictional Regulator or consistent with the regulatory asset base established in the participating jurisdiction (provided that the value of these existing assets must not exceed the deprival value of the assets); and

- the valuation of assets brought into service after 1 July 1999 and any subsequent revaluation of assets is to be undertaken on a basis to be determined by the AER having regard to the principle that deprival value should be the preferred approach to valuing network assets and the objectives specified in clause 6.2.2.

The objectives set out in clause 6.2.2 include that the AER seek to achieve reasonable recognition of pre-existing policies of government regarding transmission asset values, revenue paths and prices.[118]

The SRP[119] states that the AER's preferred approach to asset valuation is:

> "…*locking the value of the opening asset base of the prior regulatory period but adjust for inflation and depreciation, and assess capital expenditure incurred during the regulatory period on the basis of the capital expenditure regulatory arrangements set out in Chapter 5 [of the SRP].*"[120]

The roll forward will be on the basis of actual depreciation, rather than the depreciation allowed for in the previous regulatory decision.[121] However, the SRP does not set out all of the mechanics of the roll-forward, such as:

- whether the CPI used to roll-forward the asset base will be the forecast CPI at the time of the last determination, or actual outturn CPI;

- whether expenditure will be rolled into the asset base on an 'as commissioned' or 'as spent' basis; and

- the treatment in the final year of the determination, when information on actual investment will not be available.

If the TNSP proposes a revaluation, the SRP states that the AER will consider the proposal based on its merits, however, the onus will be on the TNSP to make the case for departing from the preferred principle of locking in the asset base.

There are currently no specific Rules relating to the establishing of an initial asset base for MNSPs who convert to regulated status. In the case of Murraylink, the ACCC set the initial

118 Clause 6.2.2(g), National Electricity Rules

119 SRP section 4.2

120 SRP, p.10

121 Implied by the statement in the SRP that in respect of investments covered by the ex ante capital expenditure allowance, the calculation of the closing RAB at the end of the regulatory period will be the written down value of the actual investment in that period that complies with the requirements of the Rules (SRP, section 5.3).

asset value with reference to a hypothetical application of the regulatory test.[122] Currently, Directlink's application for conversion is under consideration by the AER. Directlink has argued that the approach previously taken by the ACCC would not be appropriate to apply to Directlink, because the alternative investments considered, have materially different gross market benefits.

7.1.2. Alternative Arrangements

The current Rules allow for a relatively wide degree of discretion for the AER in determining the asset base, compared with other regulatory instruments.

As noted in chapter 6, the Gas Code is relatively prescriptive about the treatment of the asset base, including principles for the implementation of the roll forward approach, the inclusion of new facilities investment in the asset base and the circumstances in which redundant assets can be removed from the asset base.[123]

In the case of electricity distribution in South Australia and Victoria, the applicable regulatory instruments in those States set out the actual dollar value of the initial asset base that must be included by the regulator, plus principles relating to how that asset value should be rolled forward.[124]

7.1.3. Relevant Issues in Evaluating Alternative Approaches

The NEL states that the Rules must require the AER to have regard to any valuation of assets applied in any relevant determination or decision.[125] The NEL places identical requirements directly onto the AER, in making a transmission determination.[126] The Rules will therefore need to be consistent with these requirements.

61. How prescriptive should the Rules be in relation to asset valuation? Is the relatively wide discretion in the current Rules appropriate? If not, are there approaches in other regulatory instruments that provide a useful guide?

62. Should the lock in approach in the SRP be elevated to the Rules? Do the principles in the SRP provide sufficient certainty as to the method by which the lock in approach will be applied? If not, what additional guidance could be provided in the Rules?

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122 More precisely, the opening regulatory asset base for Murraylink was set at the estimate of the whole-of-life cost of the optimal project (capital and operating costs, in discounted terms), less the estimate of the whole-of-life operating costs of Murraylink (in discounted terms). ACCC, Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue, Decision, October 2003, p. 26-48.

123 Clauses 8.14-8.19 and 8.27 to 8.29, Gas Code

124 South Australia Electricity Pricing Order, section 7.2(e) and Schedule 9; Victorian Electricity Supply Industry Tariff Order, 5.10(b)

125 Sections 35(3)(c) and (d), NEL

126 Sections 16(2)(c) and (d), NEL

63. Should the Rules allow for revaluation of the asset base, or further consideration of issues such as the value of land and easements? If so, under what circumstances and who should be able to initiate such a revaluation?

64. Should the Rules cover the approach to be adopted by the AER in determining the opening asset base for an MNSP that converts to regulated status? If so, what principles should be adopted?

7.2. Criteria for Determining Efficient Investment

7.2.1. Existing arrangements

As noted in chapter 6, the current Rules require the AER to seek to achieve an incentive-based regulatory regime, which provides for, on a prospective basis, a sustainable commercial revenue stream on efficient investment, given efficient operating and maintenance practices of the TNSPs.[127] The Rules also require the AER to seek to achieve an environment which fosters an efficient level of investment within the transmission sector and upstream and downstream of the transmission sector.[128] There is no additional guidance set out in the Rules as to the approach the AER is to take in determining efficient capital expenditure or the related incentive arrangements.

The treatment of new capital expenditure is discussed in chapter 5 of the SRP, which distinguishes between:

- an ex-ante capital allowance – which covers most or all of the expected investment during the regulatory period; and

- a contingent projects provision – covering very large and uncertain investments.

The SRP states that the *ex ante* cap will be determined on the basis of '…a probabilistic assessment of expected investments during the regulatory period.'[129] As noted in chapter 6, the SRP explicitly states that the allowance does not entail project-specific approval and the TNSP is not obliged to develop an identified project during the regulatory period. Instead the TNSP is required under the SRP in making its regulatory application to provide a quantified analysis of the relationship between cost drivers (such as growth in peak demand) and the resulting investment requirement. For those investments covered by the ex-ante capital expenditure allowance the SRP notes that the written down value of actual investments in that period that complies with the Rules will be used to calculate the closing RAB at the end of the regulatory period.[130]

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127 Clause 6.2.2(b), National Electricity Rules

128 Clause 6.2.2(e), National Electricity Rules

129 SRP, p. 11

130 SRP, p. 11

The SRP also makes allowance for significant but uncertain investment which is permitted to be considered separately from the main *ex ante* capital expenditure allowance.[131] The background document accompanying the SRP indicates that generally a project will be excluded from the *ex ante* cap if the expected error from including the project, is equal to more than 10 per cent of the revenue required to cover the return on and of the main *ex ante* capital expenditure allowance.[132] However, the threshold of 10 per cent is an indicative number and the final decision as to whether a project should be excluded will be at the AER's discretion.[133] The AER now refers to these projects as contingent projects.

A TNSP must link any contingent projects with unique investment triggers – such as a major point load or expected power plant. After the completion of the regulatory test process in accordance with the Rules (including any appeals) the AER will establish an incentive mechanism for the contingent project. The incentive will specify:

- an incentive period (preferred incentive design would involve a five year period);
- the target profile annual expenditure on the contingent project;
- a calculation of annual regulated revenue covering a return on and of expected capital expenditure of the contingent project; and
- a closing RAB at the end of the five year incentive period.

As with the *ex ante* capital expenditure incentive regime, it is the depreciated value of actual capital expenditure that complies with the requirements of the Rules that will be included in the RAB. As the current Rules do not allow the AER to reset a TNSP's revenues during a regulatory period, any additional revenues or appropriate adjustments to the RAB would be done in the following revenue reset.

7.2.2. Alternative Arrangements

As discussed in chapter 6, previously the ACCC's approach to determining efficient investment (as set out in the DRP) involved an *ex post* review of investment prudency. For all capital that was assessed as prudent the TNSP received the full return on and of that capital. Chapter 6 also noted that a number of regulatory regimes retain the scope for *ex post* review.

Other regimes do not involve *ex post* review of outturn expenditure prior to it being rolled into the asset base. In Victoria, the ESC previously adopted an approach of providing an explicit incentive (via an efficiency carryover mechanism) for capital expenditure, with the

131 See Appendix G of the SRP Background document, pages 142-144
132 Background Document p. 62
133 SRP, p. 12

corollary that outturn capital expenditure was deemed to be efficient, and is not subject to an *ex post* review before being rolled into the asset base.[134]

7.2.3. Relevant Issues in Evaluating Alternative Approaches

The implications of the treatment of capital expenditure for TNSP incentives were dealt with in chapter 6.

However, several other issues surrounding the regulatory approach of capital expenditure remain. For example, should the Rules provide criteria to be applied by the AER in determining what investments are considered ‘efficient’?

65. To what extent should the Rules provide guidance to the AER in relation to the determination of efficient capital expenditure?

The current Rules include requirements for the TNSPs to apply the Regulatory Test before proceeding with capital investments. There appears to be a significant degree of uncertainty as to how the outcome of the Regulatory Test links with the subsequent determination of the efficient level of investment for the purposes of determinations under Chapter 6 of the Rules.

66. What should be the role of the Regulatory Test in determining the efficiency of capital investment?

67. Should the value adopted in the Regulatory Test be taken as the appropriate asset value to include in the asset base, regardless of outturn expenditure? If so, what implications does this have for the manner in which the Regulatory Test is applied?

68. Should there be a requirement for the TNSP to reapply the Regulatory Test if the expected capital expenditure is expected to materially change? If so, should this be mandated in the Rules?

In relation to incentives for capital efficiency, the SRP currently sets out the AER’s proposed *ex ante* approach. However, the SRP’s description of the *ex ante* approach raises a number of other issues, in particular, the extent to which the *ex ante* approach provides incentives for TNSPs to undertake investment in line with the NEM objective as discussed in chapter 6.

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134 ESC Victoria Electricity Distribution Price Review, 2006-10, p.225. As discussed in chapter 6, the ESC does not proposed to continue applying an efficiency carryover mechanism for capital expenditure.

69. What operational issues arise under the *ex ante* approach set out in the SRP? Should there be different incentive rates applied to different asset categories, as implied by the *ex ante* approach? Does the *ex ante* approach affect TNSPs incentives to classify assets as long-lived?

70. If an *ex ante* approach to capital investment assessments is adopted, should the approach set out in the SRP be elevated to the Rules?

7.3. Operating Expenditure

7.3.1. Existing Arrangements

As noted above, the current Rules require the AER to seek to achieve an incentive-based regulatory regime, which:[135]

- provides an equitable allocation between TNSPs and users of efficiency gains reasonably expected by the AER to be achievable; and

- provides for, on a prospective basis, a sustainable commercial revenue stream, on efficient investment, given efficient operating and maintenance practices of the TNSPs.

The Rules also require the AER to seek to achieve an environment which fosters efficient operating and maintenance practices within the transmission sector.[136] There is no additional guidance set out in the Rules as to the approach the AER is to take in determining efficient operating costs or the incentive arrangements that should apply to operating expenditure.

The incentive properties of the current operating expenditure regime were discussed in chapter 6. With respect to determining an appropriate operating expenditure allowance, the SRP states that the AER will continue the practice of relying primarily on historic and forecast operating expenditures of the TNSP in question.[137] The SRP indicates the AER's intention to undertake further work to explore the possibility of using benchmarking to determine the operating expenditure allowance.

7.3.2. Alternative Arrangements

In setting an efficient operating cost allowance, there can be significant debate on the role of firm specific analysis versus exogenous benchmarks, and the use of actual costs.

The SRP states that the AER will look at the potential to make greater use of exogenous benchmark data in setting operating expenditure allowances. Regulators in Europe, in particular, have been working to develop comparative benchmarks for regulatory

135 Clause 6.2.2(b), National Electricity Rules
136 Clause 6.2.2(e), National Electricity Rules
137 SRP, p.13

purposes.[138] Specifically benchmarking techniques have been tried for electricity distribution businesses in the UK and the Netherlands. Such approaches seek to provide stronger efficiency incentives for businesses, by de-coupling their allowed revenues from their actual costs. They are also seen as being less instructive and information-intensive.

In relation to the use of past actual costs in determining future expenditure allowances, regulatory practice differs. The ACCC adopted an approach for gas transmission that based operating expenditure targets on past operating expenditure, with a trend adjustment to pick up changes in productivity, demand growth and input costs and a step adjustment to take account of changes in the nature and scale of the regulated business.[139] Similar approaches have been adopted for electricity distribution.[140]

The ACCC expressed a view that such an approach provided an appropriate balance between predictability and flexibility given the relatively stable nature of the gas industry. The ACCC considered that the comparatively more changeable nature of operating expenditure in the electricity transmission industry meant that an approach that placed greater emphasis on flexibility that predictability was warranted.

7.3.3. Relevant Issues in Evaluating Alternative Approaches

There are two distinct sets of issues arising in relation to operating expenditure. One set relate to the incentives provided under the regulatory approach for businesses to improve their operating efficiency. These issues were dealt with in chapter 6. The other set of issues arise in relation to the appropriate approach to determining efficient operating expenditure. In particular, to what extent are the benefits from increased certainty and transparency that may be expected from setting out guidance in the Rules offset by a loss in flexibility by the AER to determine the most appropriate approach in a given set of circumstances.

71. To what extent should the Rules provide guidance on the approach to be taken by the AER in determining an efficient level of operating expenditure? What benefits could be expected in relation to transparency and predictability? What disadvantages may there be in terms of a loss of flexibility?

72. To the extent that guidance should be provided in the Rules, what are the relevant characteristics of electricity transmission to consider in determining the form of this guidance?

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138 See for example, Ofgem (1999): *Reviews of Public Electricity Suppliers 1998-2000, Distribution Price Control Review Draft Proposals*, August 1999, Annex 3; Frontier Economics (2000): *The efficiency of the Dutch network and supply companies, A Final Report prepared for DTe*, London, 1 August 2000.

139 See discussion in ACCC Statement of Principles for the Regulation of Electricity Transmission Revenues – Background Paper, p.68.

140 See for example ICRC, Investigation for Prices for Electricity Distribution Services for the ACT, 22 March 2004, p.71.

73. Should the Rules provide for the application of benchmarking by the AER in determining an efficient level of operating costs?

74. Should the approach set out in the SRP be elevated to the Rules? Should the Rules provide for the future adoption of benchmarking approaches?

7.4. Depreciation

Currently the Rules do not provide any explicit guidance to the AER in relation to the approach to depreciation.

The SRP makes no statement on the AER's approach to depreciation, except that it is an input in both the calculation of a TNSP's maximum allowable revenues and regulatory asset base.

In contrast, the Gas Code requires a depreciation schedule to be developed and sets out the principles that the depreciation schedule should be designed to meet, including that the schedule is adjusted to the extent reasonable to reflect changes in the expected economic life of an asset or group of assets.[141]

75. What issues (if any) arise from the current treatment of regulatory depreciation?

76. Is there a need to include specific guidance in the Rules in relation to regulatory depreciation? If so, in what areas?

77. Should the Rules require an explicit link between the appropriate rate of depreciation and the threat (or not) of regulatory stranding?

78. Should the Rules require an explicit link between the appropriate rate of depreciation and the threat (or not) of market stranding?

7.5. Rate of Return

7.5.1. Existing Arrangements

The current Rules require that the AER must take into account the weighted average cost of capital of the TNSP, having regard to the risk adjusted cash flow rate of return required by investors in commercial enterprises facing similar business risks.[142] They also require that the AER have regard to the need to provide a 'fair and reasonable' risk-adjusted cash flow

141 Clauses 8.32-8.33, Gas Code

142 Clause 6.2.4(c)(4), National Electricity Rules

rate of return,[143] and that the benchmark returns are consistent with the method of valuation of new assets and revaluation, if any, of existing assets.[144]

The SRP provides relatively detailed statements in relation to the AER's approach to calculating an appropriate rate of return. The SRP sets out the formula the AER proposes to use to calculate the Weighted Average Cost of Capital (WACC), which is a nominal, post-tax vanilla WACC. The SRP also states that the AER intends to continue using the Capital Asset Pricing Model (CAPM) model to estimate the cost of equity, and makes the following points in relation to the parameters to be adopted in the model:

- 10 year government bond rates to be used as a proxy for the risk-free rate;
- the AER will accept the period used to calculate the moving average of the risk free rate (between five and 40 days) submitted by a TNSP in its application;
- market risk premium of 6 per cent;
- equity beta of 1;
- proposal to calculate a benchmark debt margin, corresponding to a 10 year term and a benchmark 'A' credit rating for a TNSP;
- gearing level at 60 per cent for a benchmark TNSP;
- average gamma of 0.5; and
- debt and equity raising costs to be treated as operating expenditure items and the AER will undertake a further review of debt and equity raising costs and hedging costs.

7.5.2. Alternative arrangements

The extent of guidance in the current Rules in relation to the rate of return is again relatively high level.

The Gas Code includes a general principle that the rate of return used in determining a Reference Tariff should provide a return which is commensurate with prevailing conditions in the market for funds and the risk involved in delivering the Reference Service.[145] It then provides an example of the basis on which the rate of return may be determined ie, via the CAPM, and provides general guidance on the assumptions that should be made regarding financing structure.

143 Clause 6.2.3(d)(4) and 6.2.4(c)(5), National Electricity Rules
144 Clause 6.2.3(d)(4)(v), National Electricity Rules
145 Clause 8.30, Gas Code

In contrast, the EPO in South Australia sets out the detailed formula that the regulator is required to adopt and provides a mixture of structured guidance and prescription in relation to the various input parameters.[146]

A further issue is whether the WACC should reflect benchmark assumptions regarding the TNSPs' capital structure, or whether the regulator should model the business' actual capital structure. The assumption of a benchmark structure provides an incentive for businesses to try to outperform the financing costs associated with that structure, since they are able to retain the value of the difference. A calculation of a TNSPs' actual financing costs is likely to be highly complex. However, by the continual assumption of a benchmark structure, users may end up paying more than the true cost associated with capital financing, and, in contrast to other cost components of regulated revenues, do not end up sharing in the efficiency benefits achieved by the TNSP.

It is possible to envisage a further alternative approach, under which the appropriate values of each of the WACC parameters was periodically examined and decided upon. Those values would then be applied for all regulatory determinations until the next periodic review. Such an approach would recognise that there is limit to the precision with which the rate of return can be determined, but would go some way towards providing greater certainty to the market on the derivation of the WACC.

A further recognition of the inherent uncertainty surrounding the rate of return would be the adoption of an approach whereby the regulator could only modify a business' proposed rate of return if it lies outside of a plausible range, rather than requiring the WACC to be the best estimate available. This approach is discussed further in chapter 9.

7.5.3. Relevant Issues in Evaluating Alternative Approaches

An important issue in relation to the WACC is again the extent to which the Rules should provide prescriptive guidance in relation to the way in which the return is to be calculated.

79. What guidance should be provided in the Rules in relation to the calculation of an appropriate rate of return? Should the Rules be more prescriptive than currently?

80. Should the form of WACC (eg, nominal, vanilla post-tax), the WACC model (eg, CAPM) or any of its components (eg, approach to risk free rate, debt premium, beta, credit rating) be prescribed in the Rules?

81. To what extent should the WACC continue to be based on assumptions of a benchmark capital structure?

146 South Australia EPO, Schedule 10 Reset Schedule

82. Should the principles in the SRP be elevated to the Rules?

83. Should the Rules prescribe a process for the periodic review of relevant WACC parameters? If so, how frequently should such a review be undertaken: for every determination or less frequently? Who should undertake such a review?

84. Should the Rules allow for the determination to be re-opened if market conditions change?

7.6. Tax

7.6.1. Existing Arrangements

The current Rules do not contain any guidance in relation to the treatment of company taxation in making a regulatory determination. It is therefore currently left open to the AER to decide whether the regulatory approach should be on a post-tax or pre-tax basis.

The SRP establishes a post-tax regulatory regime where the required compensation for company tax is provided in the annual cash flow requirements of the TNSP. However, the SRP makes no explicit statement on how tax will be calculated except to say that compensation for tax in the MAR will be equal to 'expected business income tax payable.'[147]

To date the ACCC has generally accepted the TNSP's proposal regarding the existing tax value of regulatory assets and the remaining tax asset lives which are used to calculate its tax liabilities during the regulatory period.

7.6.2. Alternative Arrangements

The Gas Code is similar to the current electricity Rules in that it doesn't provide any explicit guidance in relation to the treatment of taxation. The ACCC has adopted a similar post-tax approach for gas transmission. The post-tax approach is also adopted by the ESC in Victoria, for gas and electricity distribution.

In contrast, the jurisdictional regulators in the ACT, NSW and South Australia adopt a pre-tax modelling approach that does not explicitly calculate required compensation for tax in required revenues but instead provides compensation through an increased rate of return to gas and electricity distribution businesses, using the statutory tax rate.

An alternative pre-tax approach that is sometimes raised would be to compensate for tax through the rate of return, but to use effective (rather than statutory) tax rates. The effective tax rate could either be calculated over the regulatory period or over the life of the regulated asset.

[147] SRP, p.5

As a further alternative, in Queensland, the amount of tax payable is estimated by the distribution business and approved by the Queensland Competition Authority (QCA) at the start of the regulatory period, with any differences between forecast and actual tax paid subject to an unders and overs process on an annual basis.

7.6.3. Relevant Issues in Evaluating Alternative Approaches

A further issue is therefore the extent that the Rules should prescribe the methodology for compensating business for the cost of company tax.

The original adoption of the post-tax approach to regulatory modelling was to address concerns that a pre-tax approach that used statutory tax rates would over-compensate the regulated business for the cost of tax, due to the presence of accelerated depreciation provisions. The allowance of accelerated tax depreciation on new capital investments effectively defers the payments of taxation so that the effective tax rate (ie, the percentage of taxes paid in relation to regulatory profits) is lower than the statutory tax rate in the earlier years. However once the accelerated depreciation allowance is exhausted the effective tax rate rises above the statutory tax rate (the 'S-bend' effect).

The removal of accelerated depreciation removes this effect in relation to new assets. However, the impact of accelerated depreciation on effective tax rates continues, as the tax value of assets that previously received accelerated depreciation will be significantly below their regulatory value and as a result a TNSP's regulatory depreciation will be greater than its tax depreciation. This has a tendency to increase the effective tax rate above the statutory rate.

Furthermore, the post-tax approach removes the necessity to adopt a conversion formula that transforms the post-tax WACC calculated using the CAPM into a pre-tax WACC used to calculate regulated revenues. None of the conversion formulae commonly proposed is complex enough to account for the effects of inflation, tax deductibility of nominal interest rates and tax depreciation. There is, therefore, a trade-off between the complexity of the formula and its degree of accuracy in accounting for the full impact of taxation on the return earned.

In addition, it is envisaged that the AER will also take over the role of regulating gas and electricity distribution. As noted above, some of these businesses are currently regulated on a pre-tax approach.

Under both a post-tax approach, or a pre-tax approach the TNSP has an incentive to adopt an efficient tax policy, since the business gets to retain (or wears) any difference between anticipated and actual tax costs. Under a pass-through approach, as adopted by the QCA, this incentive is absent.

85. Is a post-tax or a pre-tax approach appropriate for electricity transmission? What proportion of a TNSP's assets have been subject to accelerated depreciation for tax purposes?

86. Are there transparency benefits associated with a pre-tax approach? To what extent are these outweighed by the accuracy and complexity of the associated WACC conversion formula?

87. Is a convergence of modelling approaches likely to be desirable as the scope of AER energy network regulation widens? That is, are there benefits in the Rules requiring either a post-tax or a pre-tax modelling approach across all sectors?

88. What guidance (if any) should be provided in the Rules on the derivation of the cost of tax, ie, synthetic or actual information on tax values of assets (and so depreciation), financial structure, capitalisation policies?

89. Is it appropriate for the TNSP to face incentives in relation to its tax costs?

7.7. Analysis of the Financial Impact of a Revenue Determination

7.7.1. Existing Arrangements

The current Rules require the AER to have regard to the on-going commercial viability of the transmission industry and any other relevant financial indicators.[148]

To date the ACCC has discharged this duty by calculating and analysing a series of financial indicators. The purpose of the analysis is to determine the impact of the revenue decision on the ability of the TNSP to obtain credit. In calculating the financial indicators the ACCC has assumed that the TNSP's actual costs will equal those determined in the revenue decision. In particular:

- actual operating costs will equal operating expenditure allowance;
- the TNSP's capital structure is similar to the benchmark gearing level used to determine the WACC; and
- the TNSP's actual debt costs equals the rate of return on debt.

The ACCC's analysis has not considered the impact of the potential differences between the TNSP's actual costs and those set out in the revenue determination.

148 Clauses 6.2.4(c)(8) and (9), National Electricity Rules

7.7.2. Alternative Arrangements

A similar form of financial ratios analysis is conducted by jurisdictional regulators in their electricity distribution decisions.

There are no comparable requirements in the Gas Code to consider the on-going commercial viability of the gas industry or any other relevant financial indicators. In practice no regulator includes an analysis to determine the impact that its revenue decision has on financial indicators of a gas transportation business.

An alternative approach would be to base the assessment of financial ratios on a probabilistic assessment of potential outcomes, rather than assuming that the TNSP is able to meet the targets established in the determination.

7.7.3. Relevant Issues in Evaluating Alternative Approaches

An issue is whether the Rules should continue to require the AER to consider the on-going commercial viability of the transmission industry and any other relevant financial indicators.

90. What is the role for assessment of financial ratios? What value (if any) does it add?
91. Is there any benefit in continuing to calculate financial ratios on the basis of costs set out in the revenue decision? Are their alternative approaches that would be more meaningful?

8. Extent of Discretion and Design of the Rules

8.1. Principles for Determining Appropriate Discretion

As highlighted in chapter 1 of this Paper, increasing regulatory certainty is a key focus for this Review. Submissions to the Scoping Paper indicate that a number of stakeholders believe that the current regulatory regime is too uncertain.[149] Responses also called for a greater degree of guidance to be provided in the Rules to the AER on the basic transmission revenue determination process.[150]

One aspect of increasing regulatory certainty is determining the extent to which the Rules should prescribe or leave open to discretion, the regulatory decisions to be made by the AER. The question as to the appropriate extent of discretion is relevant in relation to each element of the regulatory decision making process, including the appropriate form(s) of regulation, the scope of that regulation and the application of that regulation (such as determining, as appropriate, the level of various regulatory parameters and the design and application of any incentive arrangements). The higher level issue of the extent of discretion and the design of the Rules is therefore discussed in this chapter, following the more detailed discussions in chapters 4 to 7 of the appropriate regulatory approach for the Rules in each of these areas.

Principles of good regulatory design suggest that greater predictability and consistency in the regulatory regime can reduce the regulatory risks faced by TNSPs, as well as the risks faced by users of transmission services and investors in other parts of the energy supply chain. Greater certainty in the Rules governing regulation means investors are more likely to commit capital, facilitating efficient investment and the provision of long term benefits to consumers. Predictability and consistency of decision making can be increased through:

- Rules that provide clear objectives and outcomes in relation to regulatory decisions;
- Rules that provide a greater degree of guidance about the decisions to be made; and
- Rules that set out clear procedural and informational requirements thereby increasing the transparency of decision making. This is discussed further in chapter 9.

At the same time, there needs to be recognition that highly prescriptive Rules can result in insufficient flexibility for the AER to accommodate individual business environment differences and changing market circumstances. Regulatory decision making is not simply a process of collecting data to which a mechanical formula is then applied. Some of the key decisions to be made in regulating transmission necessarily involve the exercise of judgement and choice by the regulator, and require an ability to be responsive to particular factual circumstances as they arise. For example, flexibility is required where:

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149 Energy Action Group, Submission to the Scoping Paper, p. 7; NGF, Submission to the Scoping Paper, 19 August 2005, p. 1; EnergyAustralia, Submission to the Scoping Paper, 18 August 2005, p. 4

150 Energy Networks Association, Submission to the Scoping Paper, 19 August 2005, p.2

- decisions relate to parameters that change with market conditions, such as energy demand forecasts, and financial market returns to debt and equity;

- decisions rely heavily on particular factual input, often with reference to an individual TNSP's circumstances. For instance, whether or not forecasts of future costs are efficient and prudent, or whether the allocation of reported costs between regulated and unregulated activities are appropriate; and

- observations of adaptive behaviour are important for determining the appropriate level of a particular parameter, such as the penalty/reward rates applying to an incentive scheme.

In these circumstances, seeking to draft Rules that fully prescribe the regulatory approach may be inappropriate.

In addition, the theory and practice of regulation is constantly evolving in response to experience and analysis of that experience. Rules that are overly prescriptive may inhibit the ability of the AER to refine the regulatory approach as regulatory thinking develops. While Rules can be changed, there are likely to be limits, both in terms of practicability and desirability, on the frequency of Rule changes. This raises the question about how best to allow for such change without creating unacceptable uncertainty.

The subject matter is crucial to the level of discretion. Effective regulatory processes and outcomes will be best achieved by designing Rules that provide levels of prescription or discretion that are appropriate and take into account the nature and context of the various decisions to be made by the AER.

As a result, it is likely that the appropriate degree of prescription will vary across different decisions. It is also important to recognise that regulatory certainty can be provided both through Rules that set out clear objectives and guiding principles, as well as through Rules that are more detailed and prescriptive.

92. What should be taken into account in determining the appropriate degree of regulatory discretion? What are the advantages and disadvantages in leaving a wide degree of discretion for the AER? What are the arguments for and against a more prescriptive approach? Alternatively, should the Rules prescribe/confer discretion in a way that is more tailored to the specific decisions that must be made?

93. Are the principles listed above the appropriate ones to guide consideration of the appropriate balance between prescription and discretion in the Rules? Are there additional factors that should be taken into account?

94. Given that regulatory practice and methodology will evolve over time, to what extent should the Rules accommodate future change without the need for progressive amendments? Alternatively, is it preferable that future changes in approach be implemented via a future Rule change process?

8.2. Existing Arrangements

The NEL requires the AEMC to make Rules with respect to the subject matters identified in items 15-24 of Schedule 1 but does not mandate the level of prescription that should be embodied in those Rules. It is therefore be open to the AEMC, in the design of the Rules, to determine the appropriate levels of prescription/discretion in the Rules, consistent with meeting the overall NEM objective.

The approach in the current Rules for transmission regulation reflects a relatively high degree of discretion, compared with comparable instruments in other sectors. For example:

- the current Rules provide flexibility for a number of regulatory approaches to determining the asset base, including optimisation.[151] This compares with regulatory instruments applying to electricity distribution regulation in Victoria and South Australia, which require an opening RAB lock-in and roll forward approach; and

- the current Rules provide discretion on the form and methodology for determining the WACC, requiring only that it is determined with regard to the risk adjusted cash flow rate of return required by commercial enterprises facing similar business risks,[152] in contrast to an instrument such as the South Australian EPO which contains a detailed formula to be applied for electricity distribution.[153]

Some responses to the Scoping Paper have expressed the view that the extent of discretion in the current Rules contributes to a lower level of transparency and predictability, resulting in a higher risk and cost of capital being faced by TNSPs and users of transmission services.[154]

The SRP has provided clarification of the regulatory approach the AER intends to adopt where issues have been left open by the Rules, such as the determination of the opening asset base for each regulatory period. However, the SRP is itself a non-binding policy document.[155] In effect, the AER can choose to apply or depart from the SRP when it considers it necessary to do so.

As its title indicates, the SRP is a list of principles rather than a more detailed description of the regulatory methodologies and requirements the AER intends to apply. For example, the SRP sets out a preference for rolling forward the opening asset base, but does not prescribe in detail the methodology for undertaking this roll-forward, leaving the application of this principle open to regulatory discretion.

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151 Clause 6.2.3(4)(iv), National Electricity Rules

152 Clause 6.2.4(4) National Electricity Rules

153 South Australia Electricity Pricing Order, Schedule 10, Reset Schedule.

154 NGF, Submission to the Scoping Paper, 19 August 2005, p. 2

155 This is also reflected in the language of the SRP, which refers, for example, refers to "the approach the AER intends to follow", or states that the "general" or "preferred" approach is…."

8.3. Alternative Arrangements

There are a range of approaches that could be adopted in drafting the Rules to achieve greater clarity of the regulatory regime, and an appropriate balance between discretion and prescription for each of the matters to be decided in the regulatory task.

There may be areas where the Rules should mandate the approach to be adopted. For example, the Rules could direct the AER to adopt a revenue cap form of price control (as they do currently).[156]

At the other extreme, the Rules could provide for open-ended discretion in some circumstances. For example, the Rules could state that the AER is to decide on the form of price control, without providing any further guidance on potential options or the principles to be adopted by the AER in making that decision.

Between these two extremes there is a range of potential Rule design options that could, to a greater or lesser extent, structure or guide regulatory decision making. For example, the Rules could provide for the AER to decide on the appropriate form of price control, but restrict the choice to either a revenue cap or a weighted average price cap. The current Rules in relation to electricity distribution provide an example of this approach.[157] Or the Rules could require the AER to decide on the appropriate form of price control, and set out the principles on which the AER is to make that decision, such as having regard to the need to provide incentives for efficient pricing signals, and require reasons for the decision.

95. Are there other approaches that provide useful guidance on the balance between discretion and prescription in preparing the revised Rules for electricity transmission?

Currently the Rules contain an extensive list of general objectives to which the AER must have regard.[158] The existence of trade-offs within such an extensive list of objectives may be unhelpful in terms of providing clear guidance to the AER, and may reduce the clarity, and therefore predictability of the regulatory approach.[159] The NEM objective means that the inclusion of additional objectives for the AER in the Rules may be superfluous at best and potentially unhelpful if layered and competing objectives, that reduce the clarity of the regulatory regime are applied.

156 Clause 6.2.4(b), 6.2.3(b) National Electricity Rules

157 Clause 6.10.5(b) National Electricity Rules

158 Clause 6.2.2 National Electricity Rules

159 See for example the Productivity Commission review of the Gas Code which criticised the extensive list of obligations in the Gas Code and recommended the introduction of an overarching objective (Productivity Commission Inquiry Report, Review of the Gas Access Regime, 11 June 2004, p. p. XXIX and recommendation 5.1).

96. Is there a role for further objectives in the Rules given the single NEM objective? To what extent should the general objectives currently included in the Rules be removed, reduced or rationalised?

Increasing regulatory guidance does not necessarily lead to more detailed Rules. The Rules can provide clear decision making criteria on what a particular decision is intended to achieve by specifying principles to be applied or matters to be considered by the AER in making particular decisions. This type of approach can reduce the need to include further more detailed prescriptive Rules, which run the risk of being complex and inflexible. For example, the Gas Code provisions in relation to the asset base make clear the general approach to be applied in determining the opening asset base[160] and provide principles in relation to the determination of capital redundancy, including an explicit requirement to consider the impact that such a decision would have on the risk faced by the regulated business.[161]

97. What are the relative advantages and disadvantages of an approach that specifies outcomes and principles as decision making criteria in the Rules, versus Rules with greater prescription and detail?

160 Clause 8.9 Gas Code

161 Clause 8.27 Gas Code

9. Regulatory Procedures

Procedural and information-related Rules support the AER's regulatory decision making, and this chapter highlights some key issues for the design of those Rules, including:

- the procedural steps to be taken, in making regulatory decisions, including timing and obligations on the AER's to provide its reasoning;
- finding a balance between the need to obtain information for good regulatory decision making and the associated costs of providing it; and
- the extent to which the AER is able to modify or reject a proposal put forward. This is related to the issue of AER's discretion as discussed in chapter 8 of this Paper.

9.1. Procedures and Regulatory Decision Making

Clear and robust procedures can improve both the quality and transparency of regulatory decision making, thereby minimising the risk of regulatory error and contributing to certainty and predictability of the regulatory regime. There are broad public policy reasons for having open processes that enable interested third parties to participate in decision making. Well designed procedural Rules can also provide a further way to manage investor uncertainty.

9.1.1. Existing arrangements

9.1.1.1. New procedural requirements in NEL

The amended NEL states that the revised Rules to be made by the AEMC must cover the procedures to be followed by the AER in exercising its economic regulatory functions.[162] It specifically requires that the Rules cover;[163]

- the publication of notices, draft and final determinations, and giving of reasons by the AER; and
- the making of submissions (by the TNSP and by affected Registered participants) and the holding of pre-determination conferences.

9.1.1.2. The current Rules

The current Rules pre-date the new procedural requirements set out in the NEL, but they do incorporate a number of procedural requirements. Under clause 6.2.4(b) the AER is required to publish the *"process and timetable for re-setting the revenue cap"* and the process *"must provide all affected parties with a reasonable opportunity to prepare for, participate in, and respond to that process prior to the commencement of* the *regulatory control period*."

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162 Item 17 Schedule 17, NEL

163 See s.35(1), NEL and Item 24 Schedule 1 NEL

In relation to disclosure by the AER, under clause 6.2.2(i), the transmission regulatory regime to be administered by the AER must seek to achieve "*reasonable regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions*". The current Rules require the AER to publish "*full and reasonable details of the basis and rationale of the decision*" (clause 6.2.6(a)). This includes :

- reasonable details of qualitative and quantitative methodologies;
- the values adopted for each of the regulatory parameters in any calculations, including a full description of the rationale for adopting those values;
- reasonable details of other assumptions made in the conduct of analyses in relation to resetting the revenue cap; and
- full reasons for all material judgments and qualitative decisions made and options considered, and all discretions exercised which have a material bearing on the outcome of the decision.

9.1.1.3. **The SRP**

The AER has set out its proposed process for transmission determinations in chapter 3 of the SRP that includes public consultation and submissions, a draft decision and second round consultation, before a final decision.

The process set out in the SRP is not binding on the AER. The SRP itself notes that "*the process and timetable may be adjusted by the AER where the process is not prescribed by the NER and the particular circumstances justify a departure*."[164] Submissions noted that in practice, the processes and timetables adopted by the ACCC (as the predecessor to the AER) have differed from those set out in the SRP.[165] This creates uncertainty and risk.

9.1.2. Issues to be Considered

There are a number of issues arising in relation to regulatory procedure, including:

- the steps to be incorporated into the process and how fixed or flexible each of those procedural steps should be;
- timing issues in the regulatory process and how the Rules ensure that all parties adhere to timeframes so that there is no gap between the expiry of a revenue determination and the start of a new one;
- the extent to which the AER must disclose its reasoning in making a determination; and
- whether regulatory determinations for TNSPs are made sequentially or concurrently.

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164 SRP, p.13

165 Energy Action Group, Submission to the Scoping Paper, p.7

9.1.2.1. Fixed versus flexible procedural steps in the Rules

Chapter 8 of this paper canvasses the general issue of the extent of regulatory discretion. That discussion is also relevant to the design of the procedural Rules for setting a revenue determination. Mandatory procedures may promote transparency and fairness, and discourage arbitrary decision making. However, if too rigidly prescribed, procedures can slow down the processes without benefits, prevent full and frank information flows and generally make communication between the AER and the TNSP less effective.

The transparency benefits from fixed procedural requirements need to be assessed against the advantages and disadvantages of procedural flexibility.

As noted above, the NEL does set out some procedures that the Rules must cover such as the giving draft and then final decisions and the holding of a pre-determination conference. However, the question of the extent to which these and other procedures should be fixed or subject to some discretion remains open.

98. What is the appropriate balance between fixed procedures and leaving procedural requirements open to discretion in relation to setting revenue determinations, and for related regulatory functions eg assessing compliance with price controls?

99. Are there existing procedural regimes in other jurisdictions that reflect a suitable balance between flexibility and certainty?

100. Are there other jurisdictions that reflect a poor balance between flexibility and certainty?

9.1.2.2. Initial guidance to TNSPs on Regulatory Submissions

The procedural steps taken in the past by the ACCC for electricity transmission regulation differ from those taken by jurisdictional regulators for gas and electricity distribution and the process for regulating gas transmission.

In particular, the ACCC has generally not provided initial formal guidance on the content and structure of a revenue application. Appendix A to the SRP and the AER's Information Guidelines provide a standard set of guidelines for submissions. Other jurisdictional regulators have provided specific guidance in relation to each review as a first step in their review processes. For example, both IPART in NSW and the ESC in Victoria have publicly released an initial regulatory issues paper and detailed guidance on the information to be included in businesses' submissions as the first step in their regulatory review processes.

Alternatively, the propose-respond model adopted in the Gas Code requires the businesses, rather than the regulator, to take the first step in the process by submitting an application to the regulator. The Gas Code sets out what that initial application is required to cover.[166]

101. Are there benefits in requiring the AER to issue an initial framework document for each transmission review setting out specific information requirements?

102. Are there advantages in adopting an alternative process where the initial step of submitting an application is left to the TNSP?

9.1.2.3. Timing: the general timeframe for transmission determinations

Currently there is no obligation in the Rules that ensures a transmission revenue cap is set before the end of the current regulatory control period. Delays in the process can occur for a range of reasons, and the SRP enables the AER to adjust the timeframes for the revenue setting process where the circumstances justify a departure from the stated timetable. There may be some concern that this has led to uncertainty.[167]

In addition, the current Rules do not make provision for a situation where no new determination is in place at the expiry of an existing determination. Under the Rules the maximum prices a TNSP can charge are determined by reference to the revenue cap determined by the AER.[168] As a result, if a transmission determination has not been made by the AER before the end of the regulatory control period and the expiry of the existing determination, TNSPs may find themselves in breach of the Rules.[169]

The Gas Code sets out specific timing requirements in relation to the time within which the regulator must issue a Final Decision as well as minimum time periods for submissions. In practice the timeframes in the Gas Code can be extended fairly flexibly, and this was identified by the Productivity Commission as a key issue in its review of the Gas Code.[170] The Productivity Commission recommended that the Gas Code be amended so that the regulator can only extend the time period for the Final Decision once. However it has also proposed that there should be stop-the-clock provisions if judicial proceedings commence during that time period.

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166 Clauses 3.1-3.20 Gas Code.

167 EnergyAustralia, p.4,16

168 Clauses 6.2.4(b), 6.3, 6.5.8, National Electricity Rules

169 In relation to the ACCC's revenue determination for TransGrid, the NSW Minister for Energy and Utilities, through NECA, applied to the ACCC for a jurisdictional derogation in order to put in place interim arrangements for TransGrid's revenue cap prior to the completion of the ACCC's determination. ACCC, Applications for a Minor Variation of Authorisation, NSW Transmission Pricing Derogations, 4 August 2004.

170 Productivity Commission Review of Gas Access Regime, Draft Report, December 2003, p.335

103. Should the Rules prescribe a timeframe for transmission determinations? If so, should that timeframe be capable of extension, by whom and in what circumstances?

104. If there are limited extension provisions, what stop-the-clock provisions would be appropriate? What incentives should be provided for the regulated business and the AER to meet the required timeframes?

9.1.2.4. Timing: managing time over-runs

Under current practice, where a transmission determination is not made before the expiry of the existing determination, interim arrangements have been put in place, and the revenues earned prior to the final determination are taken into account in setting the maximum annual revenue for the TNSPs.[171]

An issue for this Review is whether arrangements for transmission revenue and pricing during any period in which there is no operational determination should be codified in the Rules and, if so, what those Rules should be.

Any change to the form of price control (specifically the adoption of a price cap rather than a revenue cap) may require alternative Rules to address a situation in which a transmission determination is not finalised by the due date.

The Productivity Commission considered the issue of backdating reference tariffs in its review of the Gas Code.[172] In its Draft Report it recommended that the regulator should have the discretionary power to backdate tariffs. However it removed this recommendation in its Final Report, on the basis that backdating may increase uncertainty, and may increase the service providers' investment risk and would have 'significant practical difficulties.'[173]

105. What provisions should be included in the Rules to create incentives and/or sanctions for both the AER and the TNSP to meet timelines for revenue reset processes?

106. How should the Rules cover a situation in which there is no operational transmission determination?

107. Does a mechanism that involves some form have "backdating" have value?

171 With respect to the ACCC's most recent decision for TransGrid, an interim MAR was established for the first year of the regulatory period based on the ACCC's Draft Decision (under the approved derogation discussed above[but it's not discussed above]), and then revenue earned in the first year was taken into account in the Final Decision when determining the X-factors for the remainder of the period.

172 Productivity Commission Review of Gas Access Regime, Final Report, June 2004, pp. 477-479

173 Productivity Commission Review of Gas Access Regime, Final Report, June 2004, p. 479

9.1.2.5. **Sequential versus concurrent reviews**

To date, revenues for the electricity TNSPs have been reviewed sequentially, one to two years apart. In contrast, for electricity and gas distribution, all like entities have tended to be dealt with simultaneously by the jurisdictional regulators.

Undertaking simultaneous reviews for TNSPs may have potential benefits in ensuring that the same approach is applied to all businesses. In particular it may limit the current iterative changes to the regulatory approach adopted for transmission, although simultaneous reviews would raise workload issues. However, there may be scope for efficiencies in considering similar issues at the same time. In addition the AER's work flow will change significantly at the point when responsibility for gas and electricity distribution regulation is transferred.

108. What benefits or costs may be expected in requiring all electricity transmission determinations to be undertaken simultaneously?

9.1.2.6. **Requirements on the AER to disclose its reasoning**

The NEL specifically requires the revised Rules to oblige the AER to give reasons for its decision making.[174] The issue for discussion is how prescriptive those Rules should be about the content of those reasons.

The current Rules contain provisions in relation to information disclosure by the AER, including reasonable details of the qualitative and quantitative methodologies it has adopted. In relation to the provision of detailed information on regulatory modelling, the ACCC's practice has varied. For its more recent determinations, the ACCC has made the populated version of its PTRM model available to the relevant TSNP, but not publicly available. Regulators in other jurisdictions provide quantitative modelling information to some extent, with varying practice as to whether or not the components of determinations are in the public domain. An issue for this Review is therefore what the regulatory practice in this regard should be and whether this should be prescribed in the Rules.

109. What information should the AER be obliged to include in a statement of the reasons for a determination?

110. What are the arguments for and against a requirement in the Rules for the AER to provide details (either publicly or to the affected TNSP) of the modelling that underpins specific transmission determinations?

[174] Schedule 1, Item 24(c), NEL

9.2. Regulatory Information

Good quality information given in a timely way forms an important part of effective regulation. Information may be needed by a regulator at a number of points, namely:

- At each phase of the process for setting a regulatory determination;
- annual reporting; and
- on an *ad hoc* basis in relation to regulatory functions other than the making of a determination.

A well recognised challenge for regulatory decision making is the asymmetry of information between the regulator and regulated businesses.

Regulated businesses may lack an incentive to volunteer information to the regulator when that information may be used to their commercial detriment. Regulators typically respond to concerns in relation to accuracy of information by seeking further and more detailed information, with the attendant risks that such requests become poorly targeted, or do not take sufficient account of the costs involved.

On the other hand information requests by regulators can be burdensome both in respect of the costs the business incurs in answering the request and in the diverting of management time from the task of operating the business.

A key issue is therefore what guidance, if any, the Rules should give in relation to the trade-off between the value of good information to successful regulatory decision making, and the costs of obtaining and providing such information.

It is also important to recognise that information requirements will differ depending on the form of regulation adopted. Less intrusive forms of regulation may be accompanied by more extensive information demands on the TNSPs, in order to ensure sufficient transparency. The Rules in relation to information requirements therefore need to be considered alongside the Rules in relation to the form of regulation. Similarly, the details of the regulatory approach will also determine information requirements. For example, to the extent that the approach allows for reopening of the determination, there are likely to be specific information requirements surrounding how the need for a reopening is identified.

9.2.1. Existing arrangements

The NEL (s.28) sets out the powers of the AER to compulsorily obtain information and documents. The AER has the power to obtain information or documents from any person that it believes has the information or documents that it requires to perform its functions or powers under the NEL, including its economic regulatory function. As a result, the AER has powers to obtain information from third parties as well as from the regulated businesses.

The NEL (s.18) and the TPA (s.44AAF) also set out requirements in relation to the AER's use and disclosure of confidential information.

Under the current Rules, the AER may require a TNSP to provide any information the AER reasonably requires to perform its regulatory functions (clause 6.2.5(c)). There is also express procedure for dealing with claims for confidential information (clause 6.2.6).

In terms of the provision of routine information, currently the Rules require the TNSPs to submit certified annual financial statements to the AER, in a form to be determined by the AER (6.2.5(a)). The AER has issued an Information Requirement Guidelines that sets out reasonably detailed principles for TNSPs to follow in preparing their regulatory accounts and *pro forma* statements.

Clear information requirements in the Rules and the greater level of transparency that this brings to the process, means that the scope for disputes between the regulator and the business, may be significantly reduced. Where information requirements are vague, even if seemingly less intrusive, they may be more likely to result in greater uncertainty and the opportunity for more disputes.

A particular issue that may arise in the process of making regulatory price or revenue determinations is the ability of the regulator to assess whether particular costs incurred by a regulated business are efficient when the particular costs relate to services supplied by related but unregulated business. This issue raises the question of the extent to which regulatory accounting requirements and information gathering powers in relation to third party contracts should be explicitly set out in the Rules.[175]

An important aspect of the provision of accounting information is the extent and manner in which information on regulated services is separated from information on contestable services. Clause 6.20.2 of the Rules requires the AER, and jurisdictional regulators, to develop ring-fencing guidelines. The AER has issued Transmission Ring-fencing Guidelines that contain requirements relating to accounting separation and cost allocation, in addition to physical separation and no preferential treatment.

111. Are there any perceived problems with the current Rules in relation to the provision of information, and if so, what are they?

112. Should the Rules set out high level, qualitative principles in relation to the AER's information gathering powers, or should they seek to prescribe what information is to be provided, both routinely, and/or on an occasional basis?

[175] Essential Services Appeal Panel Reference E2/2005, In the matter of the Electricity Price Determination 2006-2010 in respect of United Energy Distribution Pty Ltd and *In the matter of the Essential Services Commission Act 2001* and In the matter of an appeal by Alinta Network Services Pty Ltd.

113. Should the Rules set out the minimum relevant requirements in relation to the content of regulatory accounts?

114. Is there a need to make specific provision in the Rules in relation to information requirements for third party contracts?

9.2.2. Alternative Arrangements

In relation to regulatory accounts, the current provisions in the Rules and the information guidelines prepared by the AER appear similar to the arrangements applying to jurisdictional regulators for electricity distribution.

The arrangements are different in the gas sector, where the AER has issued Regulatory Reporting Guidelines for Gas Pipeline Service Providers that set out principles for service providers to develop their own regulatory accounting manuals to be approved by the AER and used to govern the preparation of accounts.

115. Are the current requirements in the Rules about the content of the Regulatory Accounts satisfactory? Should the Rules be more prescriptive on any specific matters relating to regulatory accounts?

116. Would there be any advantages in adopting the model used for gas pipelines which requires the regulated business to develop its own regulatory accounting manual, consistent with guidelines produced by the AER?

9.3. Basis on which the AER can Reject or Modify a TNSP's Proposal

A further issue for the drafting of the revised Rules is the extent of the powers of the AER in relation to the application or proposal submitted by the TNSP, and in particular, whether the AER is able to reject or modify the TNSP's application and on what basis.

9.3.1. Existing Arrangements

Current practice for electricity transmission is for the AER to approach decisions on individual regulatory parameters recognising there is a range, but attempting to determine the best or most likely estimate. This is consistent with the AER having full discretion to reject or modify a TNSP's application where it is not satisfied that the values adopted represent the most likely estimate.

9.3.2. Alternative Arrangements

As noted in chapter 8, many of the parameters that need to be addressed by the AER in making its regulatory determination are difficult to prescribe in advance, since many of them depend on future market conditions. This was highlighted as an issue by the Productivity Commission in its review of the Gas Access Regime.[176]

The uncertainty involved in basing regulatory decisions on forecasts of costs, demand and financial market parameters, gives rise to the potential for regulatory error. In other sectors this has led to calls to limit the regulator's discretion to reject or modify a proposal to those regulatory parameters where the business's proposal or application is outside a plausible range, as distinct from approaching the decisions on a best estimate basis.[177] Such an approach recognises that there is potential for differing views on what should be taken as the best estimate, and also recognises the potential for regulatory error.

This approach is reflected in the ruling made under the provisions of the Gas Access Code by the Australian Competition Tribunal that, in the case of GasNet, it was up to the service provider to choose the model for establishing the rate of return.[178] Specifically the Tribunal concluded that under the Code, it was not open to the ACCC to choose some other model because it believed that an alternative model would better meet the objectives of the Gas Code. Although the decision focused on the consistency of parameters within the model for establishing the rate of return, the principles established by the Tribunal have been interpreted by some as extending to the choice of potentially all regulatory parameters.

The question as to the power of the AER to modify or reject a TNSP's application also raises the issue of the extent to which the regulator should err on the side of the regulated business in assessing business's proposals. The Productivity Commission in its review of the National Access Regime expressed the view that the consequences of overinvestment as a result of a regulator setting a rate of return that overcompensated businesses would have less impact on the long term interests of infrastructure users than the cost of underinvestment from setting too low a rate of return. It concluded that "*access regulators should be circumspect in their attempts to remove monopoly rents*".[179]

In considering Rules to address the trade-offs raised by this issue, the Commission will need to develop Rules which best facilitate the long term interests of electricity consumers. However, requiring the AER to accept a TNSPs' proposal where it lies within a plausible

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176 Productivity Commission, Review of the Gas Access Regime, June 2004, Finding 7.9, p.LIV.; See also Productivity Commission Draft Report, December 2003, p. XXVII

177 Specifically the Productivity Commission has recommended this approach to calculating the *ex ante* rate of return, Productivity Commission Review of the Gas Access Regime, Recommendation 7.9, p. LII. Some elements of the public debate around the propose-respond model also amount to a suggestion that the discretion of the regulator to reject or modify proposals should be changed, for most if not all regulatory decisions. It should be noted that such an approach is only one variant of the propose-respond model, and is not a corollary to a change in the sequencing of steps in the regulatory process.

178 Australian Competition Tribunal, Application by GasNet Australia (Operations) Pty Ltd, 2003 ACompT 6, 23 December 2003

179 Productivity Commission, Review of the National Access Regime: Inquiry Report No. 17, 28 September 2001, p.83

range could give rise to both disputation about the extent of the permissible range and to businesses proposing values towards the end of the range that would be of commercial benefit to them.

9.3.3. Relevant Factors in Evaluating Alternative Approaches

In considering the development of appropriate Rules in this area, it is relevant to consider the benefits that may be expected from changing the basis on which the AER can reject or modify a TNSP's application/proposal and any potential difficulties there may be with this approach. The MCE's SCO has sought comment as to whether the adoption of a criterion for decision making that values should be accepted if they lie within a plausible range could imply more disputes and cost in the future, with possible adverse implications for the objective of improving the degree of certainty.[180]

117. Is requiring the AER to accept TNSPs' proposal if they lie within a plausible range an appropriate way to deal with the potential for regulatory error? What other approaches may be relevant?

118. What is the likely impact of such an approach on the extent of regulatory certainty? Are regulatory outcomes more or less easy to predict if the decision criterion is within a plausible range, rather than the best or central estimate?

119. What would be the basis on which the AER is to determine that an outcome is within a plausible range? To what extent could this be by reference to objective criteria or would it by need to be at the AER's discretion?

The second issue is the extent to which such an approach would be expected to result in a bias away from a central estimate, in favour of TNSPs, and whether such a shift would be consistent with outcomes sought by the NEM objective.

120. Would such an approach represent an erring towards the interests of investors?

121. If so, is that an appropriate objective given the value apparently placed by customers on reliability and security in the long run? Are the consequences of underinvestment in electricity transmission of more detriment to achieving the market objective than the consequences of overinvestment?

122. If such an objective is appropriate, are there alternative ways of achieving it? Would such alternatives better achieve the market objective?

180 Ministerial Council on Energy Standing Committee of Officials, Review of the National Gas Pipelines Access Regime, Consultation Paper, August 2005, p.20

9.4. Savings and Transitional Issues

The proposed Rules to implement the outcomes of this Review will need to consider the impact of those new Rules on any existing determinations made, arrangements entered into or actions taken, under the existing Rules.

For example, TNSPs current revenue determinations made under the old Rules, would, without any savings or transitional Rules, be subject to the new Rules when they commence, and may be in breach of the new requirements.

Clarity and certainty is a theme of this Issues Paper, and savings and transitional Rules should provide clarity and certainty to TNSPs and other affected persons, in managing the change from the old Rules to the new.

Well designed rules that are clear and certain generally operate in a prospective and non-discriminatory way. So for example, when new laws are made existing actions, decisions and instruments which have not expired would generally be "continued" and given legal status under the new laws.

However, for certain purposes (such as a variation, review or appeal) in relation to a continued revenue determination, the transitional Rules may specify that the old Rules (or even the old National Electricity Code) apply in those circumstances. The recent amendments to the NEL included a range of transitional provisions which may provide a useful model for consideration in dealing with the likely issues to be managed.[181]

There may be other specific arrangements or issues that will require support of savings and transitional Rules. For example, Powerlink Queensland will be part way through a review process during 2006, and, depending on relative timing, there may be a need to provide savings and transitional Rules to give continuity and support for those processes.

123. What issues need to be supported or provided for in savings and transitional Rules? What is the best approach to the management of these issues?

9.5. Consequential Amendments and Jurisdictional Derogations

The AEMC will make all consequential amendments to the Rules that are necessary to implement the transmission revenue and pricing Rule changes. The AEMC seeks views and comments on any consequential amendments that may be necessary.

The AEMC specifically seeks feedback from participating jurisdictions whose current jurisdictional derogations may be affected by the substitution of new transmission revenue and pricing Rules.

181 See Schedule 3 National Electricity Law and Schedule 2 National Electricity Regulation (South Australia).

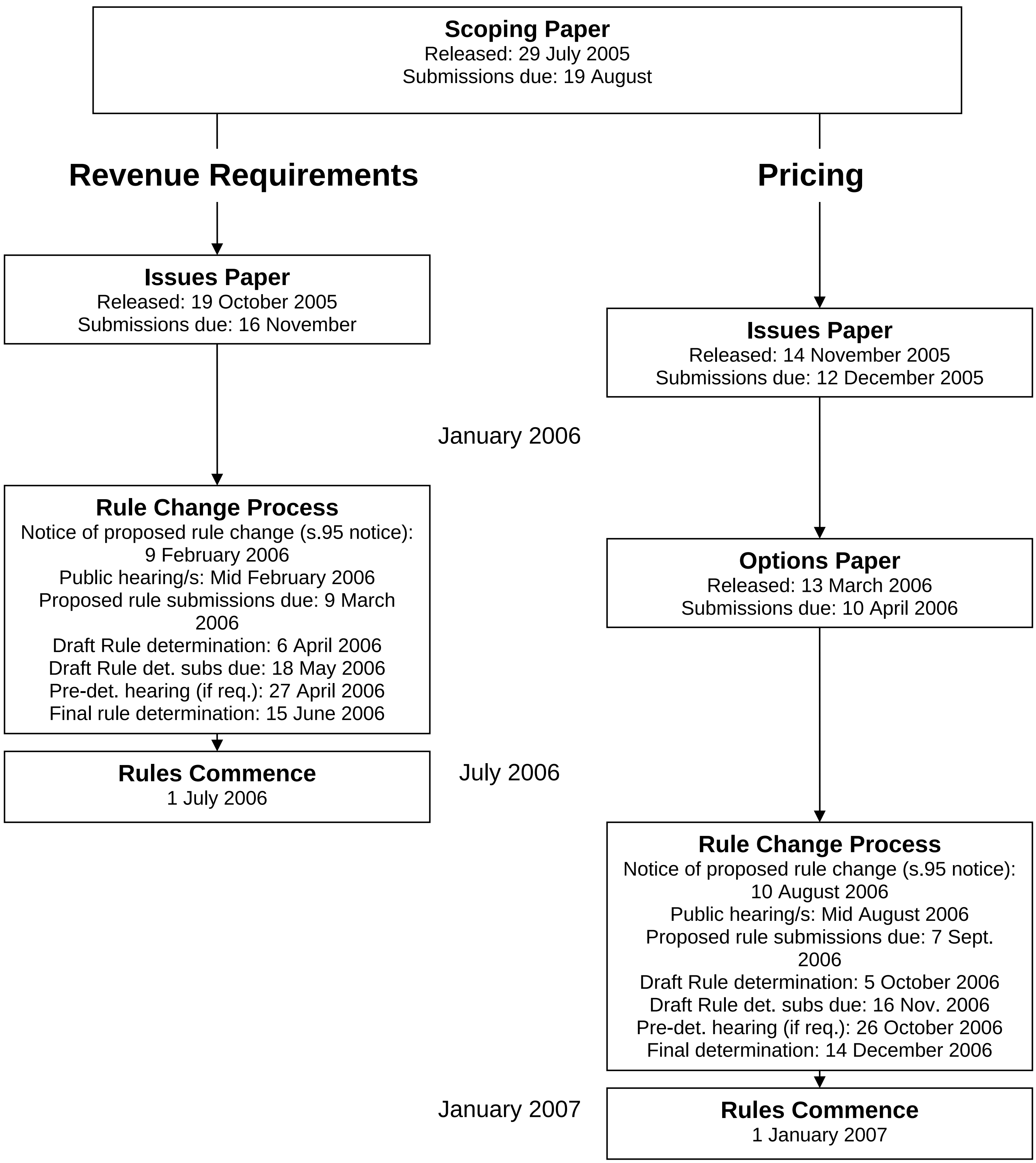
9.6. Other Pending Rule Changes Related to the Review

The Commission has received two Rule proposals that relate to issues which are relevant to this Review. ElectraNet SA, Powerlink Queensland, SPI Powernet and Transend Networks have submitted a proposal to allow the AER to vary a regulated revenue cap to take account of matters that were not included in original transmission determinations. This is either through a process of revenue cap reopening, as envisaged in the SRP, or through a cost pass through mechanism.

TransGrid has submitted a participant derogation to allow contingent projects identified in TransGrid's revenue determination, to be included in their regulatory asset base once certain triggers are met.

The Commission is considering both applications and will be progressing them in advance of the Rule change process for this Review. In doing so, the Commission will take into account the ongoing developments in this Review.

Attachment 1: Review Process



Attachment 2: Provisional Key Dates

Electricity Transmission Revenue and Pricing Review

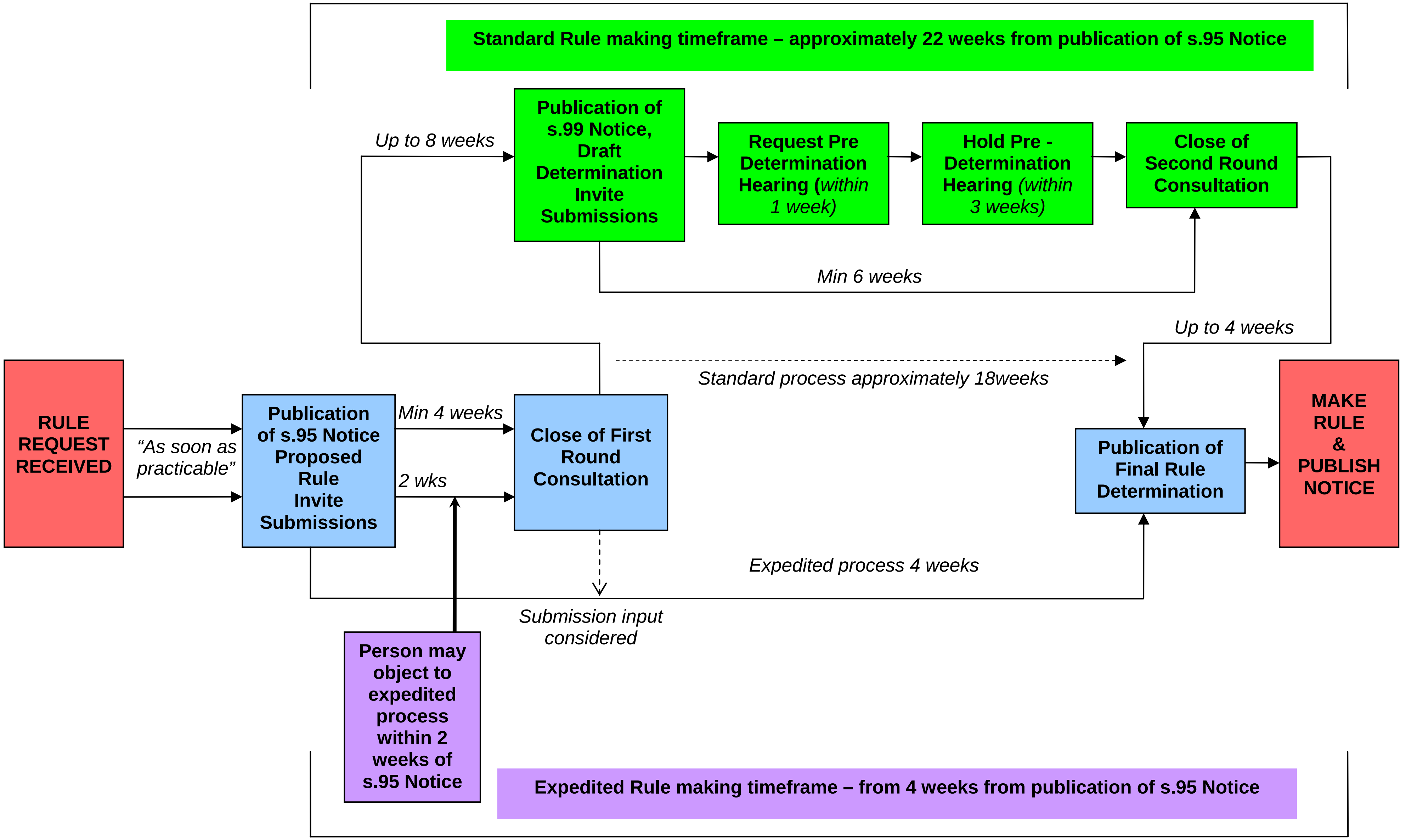
	Issue		Action From		
Action Item	**Revenue Requirements**	**Pricing**	**AEMC**	**Stakeholders**	**Date**
Release of Process and Scoping Paper for transmission revenue requirements and pricing	✓	✓	✓		29 July 2005
Submissions due on Process and Scoping Paper for transmission revenue requirements and pricing	✓	✓		✓	19 August 2005
Release of Issues Paper for transmission revenue requirements	✓		✓		19 October 2005
Submission due on Issues Paper for transmission revenue requirements	✓			✓	16 November 2005
Release of Issues Paper for transmission pricing		✓	✓		14 November 2005
Submissions due on Issues Paper for transmission pricing		✓		✓	12 December 2005
Release of notice of proposed Rule for transmission revenue requirements (s.95)	✓		✓		9 February 2006
Public hearings for transmission revenue requirements (s.98)	✓		✓	✓	Mid February 2006
Submissions due on notice of proposed Rule for transmission revenue requirements (s.97)	✓			✓	9 March 2006
Release of Options Paper for transmission pricing		✓	✓		13 March 2006
Release of draft Rule determination for transmission revenue requirements (s.99)	✓		✓		6 April 2006
Submissions due on Options Paper for transmission pricing		✓	✓		10 April 2006

	Issue		Action From		
Action Item	**Revenue Requirements**	**Pricing**	**AEMC**	**Stakeholders**	**Date**
Deadline for interested person or body[182] to request the AEMC to hold a pre-final Rule determination hearing (s.101)		✓		✓	13 April 2006
Submissions due on draft Rule change for transmission revenue requirements (s.100)	✓			✓	18 May 2006
Pre-determination hearing for transmission revenue requirements (if requested) (s.101)	✓		✓	✓	27 April 2006
Release of final determination for transmission revenue requirements project (s.102)	✓		✓		15 June 2006
Rules commence for transmission revenue requirements project and options paper for transmission pricing (s.104)	✓		✓	✓	1 July 2006
Release of notice of proposed Rule for transmission pricing (s.95)		✓	✓		10 August 2006
Public hearings for transmission pricing (s.98)		✓	✓	✓	Mid August 2006
Submissions due on notice of proposed Rule for transmission pricing (s.97)		✓		✓	7 September 2006
Release of draft Rule determination for transmission pricing (s.99)		✓	✓		5 October 2006
Deadline for interested person or body[183] to request the AEMC to hold a pre-final Rule determination hearing (s.101)		✓		✓	12 October 2006
Pre-determination hearing(s) for transmission pricing (if requested) (s.101)		✓	✓	✓	Before 26 October 2006
Submission due on draft Rule change for transmission pricing (s.100)		✓		✓	16 November 2006
Release of Final determination for transmission pricing (s.102)		✓	✓		14 December 2006
Rules commence for transmission pricing		✓	✓	✓	1 January 2007

[182] An interested person or body means a person or body that has made a written submission or comment under s.97 or s.100 of the NEL

[183] An interested person or body means a person or body that has made a written submission or comment under s.97 or s.100 of the NEL

Attachment 3: Statutory Rule Making Process



Attachment 4: International Summary[1]

Market	Form of Regulation	Form of Price Control	Scope of Regulation	Asset Valuation and Roll Forward	Assessment of New Capital	Capex/Opex Incentive Schemes	Cost Pass-through Arrangements
Argentina	Prices are now negotiated between Transener and Ministry of Energy.	Price cap until 2001. In 2001, price cap clauses were removed.	NA	Book costs and projections.	NA	NA	NA
Chile	Cost-of-service regulation used to set 'reference charges'. Access charges are negotiated between transmission owner and generators.	Access charges set every five years.	NA	Replacement cost (a useful life of 30 years and a rate of discount of 10% is considered for these investments).	NA	No specific incentives.	NA
England and Wales	Building blocks. CPI-X revenue control allows the network owner to earn revenues equal to forecast opex, depreciation, taxes; and a return on capital.	Revenue cap.	Activities that are treated as excluded services, e.g. provision of new connections, are of relatively small scale in revenue terms. Businesses are limited to earn a reasonable rate of return on associated assets,	RAB rolled forward on basis of actual capex. Outturn capex in excess of allowances subject to ex-post efficiency review, before inclusion in RAB. Changes in	No explicit new investment test.	"Rolling incentive scheme" allows companies to retain the benefits of capex underspends for five years. "Sliding scale" mechanism allows companies to	Pass-through costs include business rates, licence fees; and BETTA implementation costs.

Market	Form of Regulation	Form of Price Control	Scope of Regulation	Asset Valuation and Roll Forward	Assessment of New Capital	Capex/Opex Incentive Schemes	Cost Pass-through Arrangements
			but there is no explicit cap.	accounting policies are reviewed to prevent gains from changes in capitalisation policies.		choose a higher capex allowance but receive lower rewards for any underspends. A reliability incentive mechanism sets a target level of reliability and rewards or penalises for outperforming or underperforming.	
Mexico	None. Tariffs are set to recover long-term cost recovery of all investments plus all variable costs.	State-owned transmission grid through CFE.	The Regulatory Commission (CRE) deals with private parties, issuing the transmission pricing methodology, interconnection agreements, etc. CRE does not regulate CFE.	Original cost adjusted for inflation.	No test but annual budget is approved by Congress and acquisitions are done through a competitive solicitation process.	No incentives.	NA

Market	Form of Regulation	Form of Price Control	Scope of Regulation	Asset Valuation and Roll Forward	Assessment of New Capital	Capex/Opex Incentive Schemes	Cost Pass-through Arrangements
New Zealand	"Threshold and control" regime. Thresholds are set for price and service, and amount to a screening device. Threshold breaches lead to assessment of whether or not to implement price controls. Price thresholds are of CPI-X form and, for transmission, set by reference to distribution TFP. Service threshold focuses on interruptions. Transpower has breached its price threshold in each of the two years of the scheme's operation. Control assessment pending.	Price path threshold set by reference to weighted notional annual revenue (effectively a price cap).	Excluded services: - services that are not directly related to the provision of electricity transmission; - services for which there is workable or effective competition; or - services provided under "new investment contracts".	Disclosure regime uses ODV at 30 June 2004. Choice between indexing of starting ODV or periodic reoptimisation for roll forward	Grid Investment Test, very similar to Australian Regulatory Test. Final decision on upgrades taken by Electricity Commission. Explicit consideration required of non-transmission alternatives. Unclear link to threshold and control regime.	No explicit arrangements. Incentives are implied by non-cost based approach to determining thresholds. Current situation unlikely to be stable.	Price path threshold is net of local authority rates and Electricity Commission levies.

Market	Form of Regulation	Form of Price Control	Scope of Regulation	Asset Valuation and Roll Forward	Assessment of New Capital	Capex/Opex Incentive Schemes	Cost Pass-through Arrangements
Norway	Total revenue allowance of any network company set equal to the book cost of building and running its facilities, including a rate of return. Actual profits are allowed to vary by +/-7% around the cost of capital. If actual income from tariffs exceed (falls short of) the permitted income, the extra profit (loss) should with added interest, be paid back to (recovered from) consumers in year two after the financial year.	For any network operator, individual revenue cap.	All 3 levels of transmission covered: national, regional, local. Companies required to run separate accounts for monopolistic and competitive activities, the latter excluded from revenue cap.	The RAB is based on depreciated historic cost. State subsidies may be capitalised only with regulatory approval.	The NVE (Norwegian Water Resources and Energy Administration), relies on the mechanism described in the next column but also states that "a few major investments at higher voltage levels "will have to be dealt with as special cases".	Compensation for a new investment is related to what the new investment produces in the form of an increase in the amount of energy delivered. As this compensation is also given when the existing network is utilised more efficiently, NVE does not expect this to encourage over-investment.	Allowed revenue updated annually with respect to the following factors: Forecasted inflation, forecast demand growth; and annual requirement for productivity growth.
Singapore	Building blocks. CPI-X price caps allow the network owner to earn revenues equal to forecast opex,	Price caps. PowerGrid is required to use its best endeavours to ensure that the average revenue	Regulation is limited to PowerGrid's grid business. PowerGrid must first seek EMA	Book value.	The TNSP is responsible for developing a ten year Transmission Development	An efficiency carryover mechanism applies for both opex and capex, which allows the	Exogenous costs to the Licensee which are not separately recoverable

Market	Form of Regulation	Form of Price Control	Scope of Regulation	Asset Valuation and Roll Forward	Assessment of New Capital	Capex/Opex Incentive Schemes	Cost Pass-through Arrangements
	depreciation, taxes; and a return on capital.	per kWh earned from transmission services does not exceed the maximum average revenue as calculated by the "Economic Regulation Formula".	approval to engage in other non-related activities. Approval is subject to the EMA's assessment that the activity: uses an existing competency of PowerGrid's; and provides synergies with regulated activities.		Plan. The Plan is then reviewed and revised by the Power System Operator to ensure it meets the minimum security standards as set out by the Code. The Plan must then be approved by the EMA. The EMA review is to ensure that the Plan is not excessive based on the security standards.	regulated entity to keep any positive difference between actual and allowed figures, subject to these gains being classified as efficiency gains. Service performance standards are published by the EMA with explicit penalties for non-compliance. The penalties escalate with repeated failures. The TNSP is allowed to offer mitigating reasons for failures.	and other changes in costs to the Licensee due to regulatory directives or changes in tax, licence conditions, codes; and industry framework. Including: research and development; international obligations; and investigations of offences costs.
Sweden	The 1997 Energy Act states that "the network tariffs shall be	When the "reasonableness of a network tariff is assessed, special	The requirement to charge "reasonable" tariffs based on	The Swedish Energy Agency does not use asset valuation	According to the 1997 Energy Act, a "network	Regulator collects cost data from all network companies to	Regulator allows increases in tariffs which are not

Market	Form of Regulation	Form of Price Control	Scope of Regulation	Asset Valuation and Roll Forward	Assessment of New Capital	Capex/Opex Incentive Schemes	Cost Pass-through Arrangements
	reasonable and based on objective criteria." The Swedish Energy Market Inspectorate within the Swedish Energy Agency supervises "reasonableness" of pricing relative to services provided by local transmission companies without setting an explicit RoR or price cap (ex-post regulation).	consideration must be given to the fact that customers benefit from low and stable prices and to justifiable demands of the network owners for a reasonable yield from their operations. The tariffs must be correctly costed and must be based on costs that are related to network operations, but must not differ depending on where in an area a customer is located. Since 1/2003: Individual "reasonable" price for local transmission companies is decided upon by using NPAM (Network	"objective criteria" set out in the 1997 Energy Act applies to lines belonging to all three levels of transmission (i.e. the national grid, with high voltage levels of 400 kV and 220 kV, the regional network which connects to the national grid and has a lower voltage level; and the local networks to which household and most industrial users are connected). NPAM currently applies only to local transmission companies.	and roll-forward assess whether prices are "reasonable".	concession may be granted only if the installation is considered appropriate from a general point of view" and a "line concession may only be granted for a power line with a voltage not exceeding the maximum voltage of the areas with a network concession through which the line passes if the necessity of the line can be motivated." A line concession should be broadly compatible with the detailed development plan of the area or the general	assess whether prices are reasonable. For local transmission companies, cost data are compared with the costs of a model company under the NPAM.	"unreasonable" . Also, regional transmission companies are allowed to pass through tariffs paid to the national network company.

Market	Form of Regulation	Form of Price Control	Scope of Regulation	Asset Valuation and Roll Forward	Assessment of New Capital	Capex/Opex Incentive Schemes	Cost Pass-through Arrangements
		Performance Assessment Model) – a benchmark using data on quantity and quality of supply, prices and geographical attributes of all firms. A similar model for regional companies may be developed in future.			guidelines of the development plan. An environmental impact assessment should be included in the application for a line concession. In general, the social welfare effects of investment are taken into account when assessing whether prices are "reasonable".		
US – FERC Open Access Transmission Tariff	Rate of Return (RoR) regulation. FERC authorises rates for transmission service based on a target rate of return on investments. (Cost of Service	Schedule of approved prices.	All embedded transmission costs plus variable O&M, excluding costs recovered directly via connection charges. FTR auction revenues used as an off-set	Net Book Value.	NA	NA	Congestion costs are passed-through to consumers.

Market	Form of Regulation	Form of Price Control	Scope of Regulation	Asset Valuation and Roll Forward	Assessment of New Capital	Capex/Opex Incentive Schemes	Cost Pass-through Arrangements
	Regulation).		to open access transmission tariff (OATT) revenue requirement.				

[1] Sources:

Argentina - *Ley de Emergencia Pública y de Reforma del Regimen Cambiario, 25.561, 6 de enero de 2002. ENRE Resolutions No 182/2000, 510/2001, 531/2001 y 692/2001* www.enre.gov.ar.

Chile - www.camara.cl/aindex/leyelec/ley.htm DFL N° 1 de 1982. www.cne.cl.

England and Wales - *Ofgem, Transmission Price Control Review: Initial Consultation, July 2005*. www.ofgem.gov.uk.

Mexico - *Comisión Reguladora de Energía, Methodology for the Determination of Charges for Electricity Transmission Services, Resolution Num. RES/146/2001 www.cre.gob.mx Ley de De Adquisiciones, Arrendamientos Y Servicios Del Sector Público.* www.cfe.gob.mx.

New Zealand – *Commerce Commission, Regulation of Electricity Lines Businesses Targeted Control Regime: Resetting Transpower's Thresholds from 1 July 2005 Decisions Paper and Invitation for Submissions on Draft Gazette Notice, 6 May 2005.*

Norway – the Norwegian Water Resources and Energy Directorate. www.nve.no.

Singapore – Electricity Licence for Transmission Licensee: PowerGrid Limited, Transmission Code, www.ema.gov.sg.

Sweden –1997 Electricity Act and the Swedish Energy Agency. www.stem.se.

US - *NERA analysis. Example of Open Access Transmission Tariff (OATT) in New York ISO.* www.nyiso.com/public/index.jsp.

Attachment 5: Submissions Received

1. A Solid Foundation;
2. AER;
3. AGL;
4. Alcoa;
5. Bardak;
6. Bev Smiles;
7. CS Energy;
8. Electricity Transmission Network Owners;
9. Energex;
10. Energy Networks Association;
11. Energy Users Association of Australia;
12. EnergyAustralia;
13. Energy Intensive Industries Alliance;
14. Ergon;
15. Hydro Tasmania;
16. Major Energy Consumers Coalition;
17. National Generators Forum;
18. NRG Flinders;
19. Total Environment Centre;
20. Transend;
21. TRU/International Power/Loy Yang/NRG Flinders; and
22. VENCorp

Attachment 6: Schedule 1 to the NEL items 15-24

15 The regulation of revenues earned or that may be earned by owners, controllers or operators of transmission systems from the provision by them of services that are the subject of a transmission determination.

16 The regulation of prices charged or that may be charged by owners, controllers or operators of transmission systems for the provision by them of services that are the subject of a transmission determination, and the methodology for the determination of those prices.

17 Principles to be applied, and procedure to be followed, by the AER exercising or performing an AER economic regulatory function power.

18 The assessment, or treatment by the AER, of investment in transmission systems for the purposes of making a transmission determination.

19 The economic framework and methodologies to be applied by the AER for the purposes of item 18.

20 The mechanisms or methodologies for the derivation of the maximum allowable revenue or prices to be applied by the AER in making a transmission determination.

21 The valuation, for the purposes of making a transmission determination, of assets forming part of a transmission system owned, controlled or operated by a regulated transmission system operator, and of proposed new assets to form part of a transmission system owned, controlled or operated by a regulated transmission system operator, that are, or are to be, used in the provision of services that are the subject of a transmission determination.

22 The determination by the AER, for the purpose of making a transmission determination with respect to services that are the subject of such a determination, of

(a) a depreciation allowance for a regulated transmission system operator; and
(b) operating costs of a regulated transmission system operator; and
(c) an allowable rate of return on assets forming part of a transmission system owned, controlled or operated by a regulated transmission system operator.

23 Incentives for regulated transmission system operators to make efficient operating and investment decisions.

24 The procedure for the making of a transmission determination by the AER, including

(a) the publication of notices by the AER; and
(b) the making of submissions, including by the regulated transmission system operator to whom the transmission will apply and by affected Registered participants (within the meaning of section 16(3)); and
(c) the publication of draft and final determinations and the giving of reasons; and
(d) the holding of pre-determination conferences.