AER Submission

Australian Energy Market Commission

Review of the Electricity Transmission Revenue and Pricing Rules

Revenue Requirements: Issues Paper

November 2005

1. Introduction

The Australian Energy Regulator (AER) is responsible for regulating the revenues of transmission network service providers (TNSPs) in the National Electricity Market (NEM). As the Australian Energy Market Commission's (AEMC) review of the revenue setting rules of Chapter 6 of the National Electricity Rules (Rules) is directly relevant to the AER's role as transmission revenue regulator, the AER welcomes this opportunity to comment on the Issues Paper.

The AER notes the comment of the AEMC that the key themes of the review 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]

The AER believes that these objectives provide an appropriate focus for the review. The AER is supportive of any changes to Chapter 6 that could improve the quality of regulation in terms of outcomes and process.

The AER considers that the Rules could be amended to improve clarity of the economic framework, the regulatory decision making process, and the clarity and transparency of objectives of regulation. The Rules should also provide sufficient powers to enable the regulator to carry out its functions.

The AER's views on these issues are discussed later in this submission.

First, however, the AER comments on two of the key issues raised by the AEMC paper; namely the extent to which there should be a shift away from the existing CPI-X building block approach to TNSP regulation and, second, the extent of discretion for the regulator and whether greater prescription should be included in the Rules.

2. Alternative approaches to the form of regulation

The Issues Paper canvasses some broader transmission regulatory issues relating to alternative approaches to the form of regulation (including a prices monitoring approach to transmission regulation) and the scope of regulation (including a multi-tiered approach where different forms of regulation are applied to different transmission services).

[1] Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules, Consultation Program, Revenue Requirements: Issues Paper*, October 2005, pp 9-10.

The AER believes that the building block approach, with some amendment and modification along the lines suggested later in this submission, is the most appropriate framework for transmission revenue at this time. There is considerable experience with the building block approach and as a result it is well understood.

The AER has considered issues surrounding the developments of productivity-based approaches and has previously sought consultancy advice from Dr. Darryl Biggar on whether longer term industry-wide productivity trends (as measured by Total Factor Productivity, Data Envelope Analysis or other techniques) should be used as part of the regulatory regime for regulated networks in Australia, and if so how they should be used. His paper *Understanding the Role for Relative Productivity Information in Natural Monopoly Regulation in Australia* is attached to this submission.

A regulatory approach solely based on the use of industry-wide productivity measures at this time should be approached cautiously. As Dr. Biggar's paper identifies, significant further work is required before such approaches could be used instead of the current building block approach.

However, industry-wide productivity trends can provide a useful supplement to the existing regulatory approach. The AER notes that the Utility Regulators Forum is undertaking further work on these productivity-based approaches. The regulatory framework should be flexible enough to accommodate any further developments in this area.

3. The importance of an appropriate balance between regulatory discretion and prescription

It is important to find an appropriate balance between prescription and discretion. This submission argues that the current Rules largely reflect an appropriate balance between prescription and discretion, but also highlights a number of opportunities to improve on this existing balance.

A central issue for the review is the level of specification in the Rules regarding the regulatory framework; that is whether the AER's discretion in a range of areas should be limited by amending the Rules to provide greater prescription regarding the regulatory process. The current regulatory framework in the Rules consists of outlining at a high level the appropriate form of regulation and providing high level guidance on that form of regulation. This allows greater detail on the regulatory approach to be developed by the regulator and provided in supporting guidelines, such as the Statement of Regulatory Principles (SRP). The AER notes that a similar approach to this is proposed in the rule change request on regulatory test principles that is currently being considered by the AEMC.[2]

[2] This rule change request notes that the "proposed Rule should contain a set of regulatory test principles that will provide minimum coverage guidelines for the AER to apply in promulgating the regulatory test. The principles are intended to ensure the regulatory test is promulgated in a manner which provides a level of certainty to NSPs in undertaking new network investment, while leaving significant discretion with the AER to promulgate the regulatory test and perform its role as regulator." (p 4)

The Issues Paper questions whether it is necessary to place more prescription into the Rules in order to provide investment certainty for TNSPs. The AER believes that to create investment certainty it is not necessary to prescribe in the Rules the form, mechanisms or methodologies that should be adopted for transmission regulation in great detail. Significant investment certainty can be created by the guidelines such as the SRP, which sit outside the Rules.

This has been acknowledged by a number of industry participants. For example, SPI Powernet's submission in response to the Draft of the SRP noted that the SRP:

> *"… outlines a more consistent, clear and practical framework and process while still allowing appropriate regulatory discretion. Most importantly, it is less backward looking than the previous document, focusing on creating incentives for future investment and operating decisions. In doing so, it removes significant regulatory uncertainty from the TNSPs for which they were not receiving compensation."*[3]

The current framework delivers the certainty that is cited as one of the main benefits of a more prescriptive regulatory approach, but without any of the associated risks.

There is considerable regulatory literature on the dangers of regulatory regimes that are overly prescriptive. The Office of Regulation Review (ORR) has produced a checklist to illustrate the attributes and characteristics of high quality regulation. According to the ORR, regulation should be "not unduly prescriptive" and "general rather than overly specific."[4] The Victorian Government has also cautioned against prescriptive rules.[5]

There are a number of reasons why there is significant concern with prescriptive regulatory approaches. First, as acknowledged in the Issues Paper, highly prescriptive Rules can result in insufficient flexibility for the regulator to accommodate individual business environment differences and changing market circumstances. These concerns have been highlighted by the Council of Australian Governments who noted that regulation:

> *"…should not preclude an appropriate degree of flexibility to permit regulators to deal quickly with exceptional or changing circumstances or recognise individual needs."*[6]

Second, as also recognised in the Issues Paper, the theory and practice of regulation is evolving in response to experience and analysis of that experience. The AER believes that Rules that are overly prescriptive may restrict the ability of the regulator to improve the regulatory approach as regulatory thinking develops. The OECD has

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[3] SPI Powernet, *Submission on Draft Statement of Regulatory Principles and Background Paper*, 15 October 2004, p 3.
[4] Argy, S., and Johnson, M. 2003, *Mechanisms for Improving the Quality of Regulations: Australia in an International Context*, Productivity Commission Staff Working Paper, July, p 6..
[5] Victorian Department of Treasury and Finance 2005, *Victorian Guide to Regulation*, February, pp 3-7 & 3-8.
[6] Council of Australian Governments (COAG), *Principles and Guidelines for National Standard Setting and Regulatory Action by Ministerial Councils and Standard-Setting Bodies*, Endorsed by COAG April 1995, Amended by COAG June 2004, p 6

recently emphasised the importance of adopting:

> *"…a dynamic approach to improve regulatory systems over time to improve the stock of existing and the quality of new regulations."* [7]

The ORR has also stressed the importance of regulation that is "flexible enough to deal with special circumstances."[8]

Third, the AER considers that considerable additional costs are potentially created for market participants by placing significant detail into the Rules. Where Rules are highly prescriptive, even minor changes to regulatory practice will require amendment to the Rules. Significant resources will necessarily be devoted to a rule change process. As a result, the regulatory costs associated with pursuing improvements in regulatory practice are likely to be significant under a more prescriptive regulatory approach.

The current level of prescription in the Rules is largely appropriate. The current regulatory framework provides significant investment certainty, without the reduced flexibility and future regulatory costs that come from 'locking-in' significant additional prescription in the Rules. Nevertheless, there are some areas where the existing framework can be enhanced and made more effective by providing additional prescription without changing the existing balance. These are outlined in the following sections.

4. Coverage of the Rules

The AER considers that the Rules could be amended to improve:

- certain elements of the economic framework;
- the regulatory decision making process; and
- the clarity and transparency of objectives of regulation.

The Rules should also provide sufficient powers to enable the regulator to carry out its functions.

These elements are discussed below.

4.1 Economic framework

The AER proposes that the Rules be amended to improve a number of aspects of the existing regulatory framework. This section discusses some of the main issues raised in the Issues Paper, focusing on:

- the 'lock-in' approach to asset valuation;

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[7] OECD 2005, *OECD Guiding Principles for Regulatory Quality and Performance*, June, p 3.
[8] Argy, S., and Johnson, M. 2003, *Mechanisms for Improving the Quality of Regulations: Australia in an International Context*, Productivity Commission Staff Working Paper, July, p 6

- the ex-ante expenditure framework;
- re-opener provisions; and
- a service standards incentive framework.

4.1.1 Asset valuation

The Issues Paper canvasses a number of approaches to asset base valuation, including the lock in approach and a revaluation approach.[9] In reviewing approaches to asset valuation during the development of the SRP, the ACCC received advice from the Allen Consulting Group (ACG) on the relative merits of the lock in approach to asset valuation (roll forward approach) and a revaluation approach.[10] The ACG report is attached to this submission. The ACG identified that:

> *"The most important of the distinctions between the two methodologies relates to the strength of the incentive provided to transmission network service providers to minimise cost and – determined simultaneously – the level of risk borne by transmission providers over the ability to recover costs incurred".[11]*

The ACG concluded that:

> *"…. We do not consider that the application of such a methodology [optimised depreciated replacement cost] is desirable in the long term. Given the risks associated with estimation error, it is difficult to see how the Commission [ACCC] could commit credibly to adhere to such a regulatory regime over the long term. As a consequence we do not consider the ODRC revaluation methodology to be appropriate".[12]*

The AER agrees with the conclusions of the ACG. On balance locking in the regulatory asset base is the most appropriate approach to determining an opening asset base for revenue cap purposes. The alternative approach of periodic revaluations of sunk assets is likely to lead to significant variations in asset values between asset replacement costs and historic costs. Most importantly, the uncertainty associated with a periodic revaluation approach is not likely to be in the long-term interests of customers as revaluations lead to unpredictable revenues and prices resulting in windfall gains or losses and create a risk that efficient investments may not be recoverable, thereby deterring efficient investment.

It is also important to note that there appears to be widespread support for this approach. For example, during the consultation on the SRP, SPI Powernet noted that it:

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[9] Op cit 1, p 59-60.
[10] A detailed discussion of the relative merits of the lock-in approach to asset valuation (roll forward approach) and a revaluation approach is in the attached paper *Methodology for updating the regulatory value of electricity transmission assets*, Final Report, August 2003, prepared by the Allen Consulting Group (ACG) for the ACCC.
[11] ACG, Final Report, August 2003 p.5.
[12] ACG, Final Report, August 2003, p.6.

> *"… strongly supports the ACCC's preferred position to lock in the value of sunk assets, where both the TNSP and ACCC are comfortable that valuations for sunk assets should remain permanently fixed… [This] would remove one of the most significant regulatory risks overhanging TNSPs: the risk of a regulator appropriating business value through regular revaluation…[and] greatly simplify the regulatory regime, allowing ACCC, customer and TNSP resources to focus on getting the incentives right for future investment in the transmission system and minimising future operating costs".* [13]

The AER concurs that the lock-in of asset values is an important factor in providing regulatory certainty. In particular, this approach is likely to be aligned with the long-term interests of customers by promoting incentives for future investment. Clause 6.2.3(d)(4)(iv) of the existing Rules prescribes a revaluation approach to asset valuation. However, given the considerations outlined above, the AER believes that as part of this review the Rules should be amended to either prescribe a lock-in approach to asset valuation, or to allow the regulator to adopt a lock-in approach.

The Issues Paper also seeks comment on whether the principles in the SRP provide sufficient certainty as to the method by which the lock in approach to asset valuation will be applied. Specifically, the paper asks:

- what level of prescription should apply to asset valuation in the Rules, noting that the mechanics of the roll forward applied in asset valuation is not provided in the SRP; and
- is the current level of discretion in the Rules appropriate?

The AER considers that the specification of the mechanics of the roll forward of asset values over time in the rules may be unduly restrictive. Specifically, further prescription of the mechanics of a roll forward of asset values in the Rules would inhibit the regulator's ability to adopt alternative approaches to regulation that are likely to evolve over time. Additional guidance on the mechanics of a roll forward should be at the Regulator's discretion and informed (following detailed consultation with stakeholders) in guidelines developed by the AER such as the SRP. For example, the AER is currently considering as to whether a TNSP's capital expenditure should be reported on an "as-incurred" basis or on an "as-commissioned" basis. This has implications for the roll forward of asset values over time. The AER is currently working on the development of a generic roll forward model to be applied to TNSPs to determine closing asset values at the start of a revenue control period.

4.1.2 Ex-ante regulatory framework

The Issues Paper canvasses a number of issues arising from the adoption of an ex-ante framework in the SRP for assessing capital expenditure. The AEMC notes that it intends to:

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[13] SPI Powernet, *Submission to Discussion Paper on the ACCC Statement of Regulatory Principles*, 28 November 2003, p 10.

> *"… examine the incentive properties and relative merits of both the ex ante and ex post regulatory approaches to the assessment of efficient investment..."*[14]

There are a number of possible approaches to implementing an ex post regulatory framework. At one end of the spectrum, there is a 'cost of service' approach where expenditure is not scrutinised by the regulator and a TNSP simply recovers all of its actual expenditure. However, this approach would be a fundamental departure from the current regulatory framework which requires that incentives are provided for *efficient* investment. At the other end of the spectrum, the regulator would conduct a detailed ex post review of a TNSP's capital expenditure. However, this approach creates significant uncertainty as TNSPs face the threat of optimisation after the expenditure has been spent; is highly intrusive as it requires the regulator to 'second guess' past investment decisions and also requires an assessment of the efficiency with which assets were developed; and is not consistent with the NEL and AEMC's objectives.

The AER considers that a preferable approach is to adopt an ex-ante framework. This provides both improved incentives for efficient investment and regulatory certainty, which is in the long term interests of customers and consistent with the NEM objective specified in the National Electricity Law (NEL). Issues surrounding the appropriate capital expenditure framework are outlined in the attached Supplementary Discussion Paper on the capital expenditure framework[15].

The ex-ante approach is accommodated within the current chapter 6 framework. The AER recommends that any amendments to chapter 6 continue to support an ex-ante regulatory framework for assessing capital expenditure.

4.1.3 Recovery of efficient investment cost and the ex-ante framework

The Issues Paper discusses whether an ex-post approach to capex assessments may be necessary to ensure that efficient investments that exceed an ex-ante cap or unforseen efficient expenditure may be recovered by a TNSP. This potential for 'forecasting error' is an important issue which was considered in detail during the development of the ex-ante framework. To deal with this issue, the ex-ante framework adopted by the AER provides TNSPs with the flexibility to recover additional investments during the regulatory period through the contingent project provisions and the provisions for a dynamically adjusted ex-ante cap. Contingent project provisions have been included in the regulatory framework to minimise the potential for a TNSP to be exposed to windfall losses and gains associated with significant but uncertain investments over the regulatory period. The contingent project provisions are expected to improve the accuracy of a TNSP's ex-ante allowance and ensure that the ex-ante allowance is more closely aligned with efficient costs.

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[14] Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules, Consultation Program, Revenue Requirements: Issues Paper*, October 2005, p 10.
[15] Australian Competition and Consumer Commission, *Supplementary Discussion Paper: Review of the Draft Statement of Principles for the Regulation of Transmission Revenues – Capital Expenditure Framework*, 10 March 2004.

The capital expenditure framework includes the provision for a dynamically adjusting ex-ante cap. This feature of the capital expenditure framework was not acknowledged in the Issues Paper. The regulatory arrangements are sufficiently flexible for allowed capital expenditure to be adjusted during a regulatory control period based on specified cost drivers to provide TNSPs with protection against variation in efficient costs due to changes in underlying parameters. For example, Powerlink has suggested that its revenue cap be allowed to adjust to changes in demand. This is a fundamental aspect of the ex-ante arrangements.

In addressing this issue of forecasting error, the AER considers that existing regulatory arrangements provide sufficient flexibility to enable the recovery of efficient investments. Specifically, the contingent project provisions provide the flexibility for a TNSP to recover investments that may be associated with a specific investment driver, while the dynamically adjusted cap provides TNSPs with the flexibility to recover investments associated with 'systemic' investment drivers such as demand growth or changes in input costs. These safeguards for a TNSP to recover efficient investments provide an appropriate balance between the incentive arrangements reflected in setting an ex-ante cap and enabling TNSPs to recover efficient investments.

Notwithstanding the arrangements outlined in the SRP, the existing Rules provide limited flexibility to 're-open' or amend a TNSP's revenue cap.[16] The AER considers that the Rules should be amended to enable the full implementation of a contingent project framework and a dynamically adjusted cap.

4.1.4 Service standards

The Issues Paper considers that there may be a role for economic regulation to reinforce or supplement a TNSP's service performance obligations by providing financial incentives associated with performance outcomes.

The AER, through its service standards guidelines, currently implements a transmission network service standards regime linked to a TNSP's revenue cap. The financial incentives available from achieving performance targets under the regime are capped at ±1 per cent of the TNSP's revenue-cap.

The AER supports a strengthening of the financial incentives based around the impact of a TNSP's performance on the market. However in general, the AER cautions against elevating the details of the existing performance incentive regime or a variant of this regime, (including an economic incentive linked to the costs of network constraints), directly into the Rules at this time. Further development work is required in relation to an economic incentive linked to network constraints (as discussed below) and there is limited experience to date with which to assess the effectiveness of the existing financial incentive arrangements. Rather, the Rules should provide the flexibility for the AER to implement a more sophisticated service

[16] Clause 6.2.4 of the Rules prescribes limited circumstances in which a revenue control may be re-opened. These include the provision of false and misleading information to the AER, a material error in the decision of the AER or a substantial change in ownership.

incentive scheme as part of the economic regulatory framework, following completion of the work programme on this matter as outlined below.

The Issues Paper also invites views on specific service incentive arrangements. In particular, the Issues Paper is seeking comment on how target performance levels should be set, and in cases where market impact measures are proposed, how the difficulties surrounding the identification of TNSPs' roles in causing market impacts and measuring market impacts should be addressed. The AER is currently working on transparency measures which, amongst other benefits, will provide a clearer understanding of the impact of transmission constraints in the NEM and their causal elements.

In progressing work on this issue it is necessary to establish a close working relationship with NEMMCO, the TNSPs and stakeholders. The AER has developed a very good working relationship with stakeholders and believes that the shared level of understanding of the issues has improved significantly. It is essential that this work continue to progress. Indeed, significant progress has been made in working towards publishing the first Transmission Network Service Standards Market Impact Transparency Report (MITR).[17] This report will help provide a clearer picture of the causal elements of transmission constraints including those elements that may be attributable to TNSPs' operating behaviour. It is anticipated that the MITR will be published in early 2006. Following the publication of the MITR, the AER will continue to explore opportunities flowing from increased transparency including investigating the possible introduction of an economic incentive mechanism directly linked to the cost of network constraints. The AER encourages the AEMC to take account of these developments in this review.

4.2 AER decision-making processes

The Issues Paper argues that the AER's decision making processes are a major source of regulatory uncertainty and a key focus of the review and seeks comment on the most appropriate process to be adopted.

The AER believes that its current policy of a 12 month timeframe for decision making is appropriate given the complexity of issues covered in a revenue determination and the need for appropriate consultation. A number of submissions supported the 12 month regulatory review period in the context of the development of the SRP, including Powerlink, the National Generators Forum, Transend, Ergon Energy and VENCorp. This does not prevent adoption of a shorter timeframe if opportunities allow.

In relation to the timeframes and process, the Issues Paper states that:

> *"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. This creates uncertainty and risk."* [18]

[17] The ACCC's draft decision on Market Impact Transparency Measures is attached to this submission.
[18] Op cit 1, p 78

In terms of consistency of process, all 10 revenue cap determinations made by the ACCC for transmission service providers in the NEM followed the same process (initial request for submissions, draft decision, pre-decision conference, further submissions and final decision).

In terms of the timeliness of decision making, all except the recent NSW transmission determinations were made within the timeframe set out in the SRP. The NSW processes were extended because of the release of the SRP during the revenue reset. However, the ACCC gave these TNSPs the choice of finalising the decisions within the normal 12 month process, or extending the process to accommodate the revised approach in the SRP. Both TNSPs elected to extend the process. The extensions allowed the TNSPs to submit revised capital programs. These determinations were then finalised in accordance with the agreed revised timeframe.

While the current timeframes and review processes are appropriate and have been followed in revenue determinations to date, it is productive to consider how these regulatory processes can be improved. Indeed, the AER is and will continually look for opportunities to streamline its regulatory decision-making processes.

The Issues Paper also invites views on an appropriate balance between fixed procedures and leaving procedural requirements open to the discretion of the regulator in setting revenue determinations. Rigidly specifying the detail of regulatory processes in the Rules would result in a significant loss of flexibility in the process, which could affect the quality of regulatory decisions. This flexibility is necessary to respond to issues as they arise during the regulatory decision making process. In particular, there are likely to be instances where the AER may not have complete or the appropriate information from TNSPs or a TNSP may subsequently identify further issues that need to be considered in support of its application. Safeguards would need to be included in the Rules to provide adequate flexibility to accommodate these circumstances, such as ‘stop the clock’ provisions, in the event that regulatory processes and timeframes are prescribed in the Rules.

Existing regulatory processes are specified in clause 6.2.4(b) of the Rules. However, these provisions only specify that the AER must publish its intended process and timetable prior to the commencement of the revenue control period to provide reasonable opportunities for affected parties to participate in the process.

On the basis that the timeframes and processes specified in the SRP would appear to be reasonable, the AER considers that the key aspects of the processes and overall timeline outlined in the SRP could be prescribed in the Rules if the AEMC believes that it will help meet the objectives of this review. By way of example an appropriate level of prescription might require:

- the TNSP to submit an application;

- the AER to review the application, with the review commencing when the AER is satisfied that the application provides complete information;

- the AER to publish a draft determination and provide the opportunity for submissions on the draft; and

- the AER to publish its final determination within 12 months of the commencement of the review.

4.3 Clear and transparent objectives

This review is an opportunity to significantly simplify Chapter 6 by removing any repetitive or overlapping objectives and principles. The NEL and the Rules set out over 50 principles, objectives and other matters to which the AER must have regard when setting a transmission revenue cap. In light of this, there is a clear scope to rationalise the principles and objectives in Chapter 6 of the Rules to improve its clarity and effectiveness and align it with the NEM objective.

In particular, the objectives and principles within clauses 6.1.1, 6.2.2, 6.2.3, 6.2.4 of the Rules need to be reconsidered. In some of these cases, in addition to repetition and overlapping objectives and principles, there is the potential for inconsistency between objectives. The AER suggests that the AEMC consider streamlining these clauses of Chapter 6 to simplify the reading of the Rules.

Superfluous provisions

An example of a superfluous high-level principle includes clause 6.1.1 which sets out the key principles and core objectives for Chapter 6 of the Rules. In light of the enactment of the NEM objective and its application to the AEMC and AER, this clause does not appear to add any value to the Rules. It seems unnecessary to retain a further set of objectives that sit between the NEL and the specific principles in the Rules. It is the AER's view that clause 6.1.1 can be removed in its entirety.

Repetition and overlapping

An example of repetition in the rules is demonstrated in clauses 6.2.2(b)(2), 6.2.3(d)(4) and 6.2.4(c)(5). In these three separate places, Chapter 6 states that the AER is to give weight to the need to provide a fair and reasonable, risk adjusted, cash flow rate of return on efficient investment, given efficient operating and maintenance practices. The AER suggests the AEMC seek to remove such repetition in this review.

Potential inconsistency

To prevent inconsistencies developing between these principles, it important for this review to amend the Rules to bring different principles on the same subject into line. For example section 16(2)(d) of the NEL states that:

> *"the AER, in making a transmission determination, must in accordance with the Rules:*
> *…*
> *(d) have regard to any valuation of assets forming part of the transmission system owned, controlled or operated by the regulated transmission system operator applied in any relevant determination or decision."*

However, clause 6.2.2(g)(b) of the Rules provides that the AER must seek to achieve "*reasonable recognition of pre-existing policies of governments regarding transmission asset values, revenue paths and prices". Meanwhile, c*lause 6.2.3(d)(5)(iv)(A) provides that the AER must have regard to "*the initial revenue setting and asset valuation decisions made by participating jurisdictions in the context of industry reform pursuant to the Competition Principles Agreement.*

Each of these provisions instructs the AER to have regard to previous decisions and government policies. As well as being repetitive, there is potential inconsistency in relation to the types of decisions and policies to which regard must be had; and the purposes for which the AER must do so. The AER suggests the AEMC seek to address such areas of potential inconsistency in this review.

4.4 Sufficient powers to enable the AER to carry out its functions

It is essential that the Rules provide adequate powers for a regulator to carry out its economic regulatory functions. In this regard, this review offers a good opportunity to address an anomaly in the Rules regarding the publication of TNSP information. Under the existing Rules, each TNSP is required under clause 6.2.5 of the Rules to provide to the AER annual information on the TNSP's financial performance and any other information reasonably required by the AER to perform its regulatory functions.[19]

These information requirements provide information and insight into a TNSP's performance. Annual reporting is a useful tool and provides significant benefits such as facilitating informed public input into future decisions by the AER, allowing public scrutiny of annual TNSP performance against revenue caps, and providing greater transparency of the regulatory process. Information provided by TNSPs also informs the exercise of the economic regulation functions set out in Chapter 6 of the Rules.

The AER publishes annual reports of TNSP performance under clause 6.2.5 of the Rules. However, the AER can only disclose financial information if the TNSP has provided written consent. For the publication of the 2002/03 and 2003/04 reports, one TNSP did not provide consent and the information relating to it was omitted. This has undermined the effectiveness and completeness of the reports.

The intention of the Rules' provisions regarding information gathering powers was always that the regulator would be able to publish information relating to a TNSP's financial performance. This is evidenced by further provisions in the Rules, covering instances where consent is not provided.[20] However, the oversight in the existing Rules means that the AER may not be able to publish annual data in the absence of written consent for its annual reporting function. To correct this anomaly it would be

[19] This information is prescribed in Appendices A and B of the *Information Requirements Guidelines*. The information prescribed in Appendix A is used to set revenue caps and the information prescribed in Appendix B is used in the AER's annual reporting on TNSPs' financial performance.
[20] In instances where consent is not provided, the AER can issue a notice to the TNSP of its intention to publicly release certain information.

desirable to amend the Rules to clarify that the AER has the ability to conduct this reporting function.

The Allen Consulting Group

Methodology for updating the regulatory value of electricity transmission assets

Final report

August, 2003

Report to the Australian Competition and Consumer Commission

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Executive summary

The Australian Competition and Consumer Commission ('the Commission') has requested The Allen Consulting Group to report on the relative merits of two alternative options for updating the regulatory values of the regulated electricity transmission assets at future reviews, namely:

- revalue the relevant network assets at an estimate of the valuation derived using the optimised depreciated replacement cost (ODRC) valuation methodology (and, implicitly, continue to revalue the network using the same methodology at subsequent price reviews); or to
- commence with the previous regulatory asset base for the regulated assets, and adjust for capital expenditure, depreciation, disposals and inflation during the previous regulatory period.

The change in the regulatory value from the start of one regulatory period to the next reflects the change in future income that a provider will expect arising out of the actions or events that took place during the proceeding period. Thus, to the extent that the provider had invested in renewals to the network over that period, or expanded to meet the growth in demand, the change in the regulatory value would reflect the incremental income the provider would expect from making those investments, and hence its incentive to invest.

The most important of the distinctions between the two methodologies relates to the strength of the incentive provided to transmission network service providers to minimise cost and – determined simultaneously – the level of risk borne by transmission providers over the ability to recover costs incurred.

The first of these methodologies – the ODRC revaluation methodology – would have the effect of setting prices for the use of transmission assets at the commencement of each regulatory period at a level that is (approximately) consistent with the cost structure of a hypothetical (efficient) new entrant. That is, regulated charges would be independent the costs actually incurred (that is, capital costs and operating costs) in providing transmission services.

In contrast, the second of these methodologies – the rolling forward methodology – would imply updating the regulatory asset base for a regulated transmission entity to reflect the actual outcomes for the regulated entity over the previous regulatory period. That is, the updated regulatory asset base would reflect the level of capital expenditure undertaken and return of funds (regulatory depreciation and disposals) received over the period. The practice of fixing prices independent of cost for a regulatory period – and coupling this with a carry-over of some of the benefits arising from efficiency gains into the next period – would provide a commercial incentive to reduce cost, notwithstanding the updating of the regulatory asset base to reflect actual cost.

The ODRC revaluation methodology represents the polar case along a spectrum of trade-offs relating to the strength of incentives to reduce cost, and the degree of certainty over the recovery of costs. The rolling-forward methodology, in contrast, provides a degree of certainty over the recovery of costs incurred – with the degree of certainty (and strength of the incentive to minimise cost) determined by the length of the regulatory period selected.

We do not consider that the setting of prices completely independent of cost is feasible for regulated electricity transmission businesses in the short term. The application of the ODRC revaluation approach would require significant refinement to the methodology for estimating ODRC values to the methodology used to set regulated charges – which would require a substantial investment by the Commission.

Moreover, we do not consider that the application of such a methodology is desirable in the longer term. Whether a transmission business would expect to recover the cost of continuing to provide the service – or expected to earn returns much larger than that required to justify its continued financing of the business – would depend upon the accuracy of the estimated ODRC value, for which substantial statistical uncertainty will be inevitable. Given the risks associated with estimation errors, it is difficult to see how the Commission could commit credibly to adhere to such a regulatory regime over the long term.[1] As a consequence, we do not consider the ODRC revaluation methodology to be appropriate.

Whether the balance between the strength of the incentive to reduce cost, certainty over cost recovery under the use of a five year regulatory period and efficiency carry is the most efficient balance is a matter that the Commission should keep under review. It is noted, however, that where price cap is used (which is consistent with the roll-forward methodology), the strength of the incentive to reduce cost can be increased by lengthening the regulatory period – which is a straightforward task. One means of making longer price control periods more credible would be to improve the methods used to set the rate of change of prices over the period, in particular, to place less emphasis on the use of internally generated forecasts and more on external estimates of productivity growth. We consider that work in this area would be a more productive use of the Commission's scarce resources than the refinement of ODRC estimates.

Another point of distinction between the valuation methods is the level of prices expected at each point in time in the future. The ODRC level would maintain average prices at (approximately) the level consistent with those of the hypothetical (efficient) new entrant, whereas under the roll-forward approach, average prices could be higher or lower. It is noted that the structure – rather than the average level – of charges is more important for efficiency. It is also noted that the time profile of charges of an efficient new entrant may not be the most efficient charges – and that the roll-forward methodology may permit the more efficient time profile of charges.

[1] The use of an ODRC valuation methodology equates to what was referred to as an 'engineering economic analysis' in the recent report to the Utilities Regulators Forum on different regulatory approaches (Farrier Swier Consulting, Comparison of Building Blocks and Index-Based Approaches, Report to the Utility Regulators Forum, June 2002, p.33). Farrier Swier Consulting appeared to reject the 'economic engineering approach' as one that could potentially be applied as the primary approach in Australia, although did not set out clearly the reasons for rejecting the approach (Farrier Swier Consulting, op cit, p.35).

Another relevant matter in the selection between the two methodologies is the administrative costs and simplicity of the two approaches. The application of the ODRC revaluation methodology would require a substantial refinement to the current practice, which would require a commensurate investment by the Commission and interested parties. The continued application of the methodology is also likely to be difficult, given that substantial windfall gains or losses may result (for example, from an error in the depreciation allowance). While the application of price cap regulation (and the roll-forward approach) is not cost free, it is noted that the greater use of incentive arrangements to assist the regulatory task offers scope for reducing the cost of regulation. More objective methods of setting future price paths – such as greater reliance on estimates of productivity trends rather than internally generated forecasts – would also reduce administrative costs.

A positive effect of revaluing assets at their ODRC value is that this may provide regulated entities with the incentive to have regard to events beyond the current price control period, including the most appropriate means of meeting increasing demand. ODRC valuations would ensure that the regulated entity would have an incentive to take account of the value of a flexible response.

The importance of such an incentive is an empirical matter, and is something that declines as the length of the regulatory period is extended, and would need to be traded off against the adverse effects of increased risk from the ODRC revaluation method. However, for electricity transmission, such an incentive is likely to be of little practical relevance because the provider has no incentive over the structure of tariffs, and because the regulatory test already provides a 'screen' over the efficiency of the response to demand growth.

It is noted that the references to concepts like optimal deprival value and the associated current replacement cost concepts derived from a desire in the 1980s to improve the measures of the financial performance of government business enterprises. This approximately coincided with the debate about the most appropriate measure of income for financial accounting purposes, relating to the debate between financial capital maintenance and operating (or physical) capability maintenance.

It is noted that revaluing assets at their ODRC value has similarities to concepts from the financial accounting field, such as Optimised Deprival Value and the valuation methods consistent with the operating capital maintenance concept. The regulatory asset base in regulation has a specific purpose, which is to reflect the value of the regulated assets in the eyes of the regulator at each point in time, and the test for the appropriateness of any method for updating of the regulatory asset base has a specific objective – which is to ensure that the change in the regulatory value provides incentives for efficiency, including to minimise cost but to continue to investment where it is efficient to do so. Accordingly, it need not follow that accounting conventions developed for other purposes – such as measuring the financial performance of government businesses or to derive better estimates of economic income – are appropriate for this task.

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

Chapter 1

Introduction

1.1 The brief

The Australian Competition and Consumer Commission ('the Commission') has requested The Allen Consulting Group to report on the relative merits of two alternative options for updating the regulatory values of the regulated electricity transmission assets at future reviews, namely:

- revalue the relevant network assets at an estimate of the valuation derived using the optimised depreciated replacement cost (ODRC) valuation methodology (and, implicitly, continue to revalue the network using the same methodology at subsequent price reviews); or to
- commence with the previous regulatory asset base for the regulated assets, and adjust for capital expenditure, depreciation, disposals and inflation during the previous regulatory period.

In undertaking this project, the Commission has requested that regard be had to:

- allocative efficiency issues, including the rate of technological change, the level of demand, and the market characteristics such as the age of the networks and potential augmentations in the future;
- incentives for efficient investment in regulated assets; and
- approaches that are robust, transparent, and simple.

The Commission has also noted that the report will need to consider the key issues in a manner suitable for public release and discussion. Further, reference would be made to the approaches adopted in other Australian industries and jurisdictions, and to relevant contributions in the economics literature.

1.2 Background

The regulatory asset base that is assigned to a transmission provider's assets is an important input in the assessment of regulated charges. The regulatory asset base at a point in time can be interpreted as the net present value of income that the regulatory regime would be expected to provide over the remaining economic life of those assets, at least in the eyes of the regulator.[2] Thus, the objective of the regulator when setting regulated charges can be expressed as setting charges such that regulated revenue stream has a present value equal to the regulatory asset base, given the regulator's assumptions about matters such as expenditure requirements and the cost of capital associated with the regulated activities.[3]

2 This statement assumes that the regulatory WACC is equal to the cost of capital for the regulated activities, and that expenditure on operating and capital items is exactly that assumed by the regulator for the purpose of determining regulated charges. If the regulated business outperforms against these benchmarks (ie spends less than the benchmark), while not compromising service performance, or the regulatory WACC is higher than the cost of capital associated with the regulated activity, then the expected net present value of income to the existing assets will exceed the regulatory asset base. In addition, a regulator may also include a reward for past efficiency gains in regulated charges in order to provide a continuous incentive for efficiency, which would also imply that the net present value of future

The Commission released its draft *Statement of Regulatory Principles for the Regulation of Transmission Revenues* (DRP) in May 1999, which set out the Commission's views on all the methodology it would adopt to determine the revenue caps for the regulated electricity transmission network service providers, including the methodology for setting a regulatory value for the assets that are used to provide the regulated services.[4]

In that draft statement, the Commission expressed its intention to set the regulatory value of the regulated transmission assets at an estimate of the Optimised Depreciated Replacement Cost of the relevant network when the Commission first had the opportunity to reassess the value of those assets under the National Electricity Code. It also signalled its intention to reset the regulatory value for the regulated transmission assets at an estimate of the ODRC value of the relevant network at future reviews (although not necessarily every five years).

The Commission has now set the 'first round' revenue caps for five regulated transmission providers (TransGrid, Powerlink, the Snowy Mountains Hydro-electric Authority, SPI PowerNet and ElectraNet) and is in the process of setting the revenue cap for a sixth, which will complete the revenue caps for the transmission providers covered by the National Electricity Markets. However, under the relevant provisions of the National Electricity Code,[5] the Commission's decisions over the regulatory values for the regulated transmission providers when setting the 'first round' revenue caps were constrained to the values set by a jurisdictional regulator or at values consistent with the jurisdictional valuation if one existed. Accordingly, it is assumed in this report that the Commission will reset the value for the regulated transmission assets at an estimate of their ODRC value when setting the 'second round' revenue caps for the regulated entities.

The issue that is addressed in this report is whether the Commission should continue to reset the regulatory value of regulated transmission assets at an estimate of their ODRC value into the future, either at each periodic revenue cap review or at longer intervals. The alternative approach to updating regulatory values based on ODRC estimates is to merely to adjust the previous regulatory value to reflect capital expenditure, depreciation and disposals over the period, that is, in the same manner as book values of assets are carried forward in Australia for financial accounting purposes.

income would exceed the regulatory asset base. The form of incentives arrangements that a regulator may adopt are discussed in chapter 2.

3 This statement is subject to the same caveats set out in footnote 2.

4 More precisely, the Commission determines revenue caps (referred to as the Maximum Allowable Revenue, or MAR) for the prescribed services provided by the transmission network service providers that are registered as such pursuant to the National Electricity Code. All references to regulated services and regulated transmission entities throughout this report are references to this specific class of services and entities, and references to regulated transmission assets are references to the assets required to provide prescribed services.

5 National Electricity Code, Ch.6.

Setting an *initial* regulatory value with reference to cost for the assets that are already exist at the time those assets become regulated formally has been one of the most contentious issues for Australian regulators. It is a matter for which economic principles do not provide an unambiguous answer. The assumption in this report that the Commission will reset the regulatory values of the regulated transmission assets at an estimate of their ODRC values implies that the selection between the methodologies for updating the regulatory asset bases should not be expected (*ex ante*) to lead to a windfall gain or loss to the regulated transmission providers.[6]

1.3 Structure of this Report

The remainder of this report is set out as follows.

Chapter 2 describes the analytical framework that is adopted for assessing the alternative asset valuation methodologies, and, in particular, the implications of economic efficiency for price regulation, and the regulatory tools that exist for encouraging the various facets of economic efficiency. It also discusses some of the 'regulatory tools' that are either embedded in the National Electricity Code – or implicitly ruled out by the Code.

Chapter 3 describes the two options for updating the regulatory value of regulated transmission assets in detail. A key message of the discussion is that a fair comparison between the options for updating asset values needs to consider the *complete package of measures* that could accompany the selected methodology. The practicalities associated with each methodology also need to be considered.

Chapter 4 assesses the relative merits of the alternative methodologies for updating the regulated values of regulated transmission assets, focussing on the key distinctions between the methodologies identified in Chapter 3 and pursuant to the framework for analysis set out in Chapter 2.

Chapter 5 summarises the practice on asset re-valuation in other industries and jurisdictions, the gas industry in Australia and energy regulation in the US and UK and places in context the use of the two methodologies.

[6] A further implicit assumption of this report is that the Commission would have decided how it intends to update the value of the regulated transmission assets prior to setting the 'second round' revenue caps, and that – should it elect to reset regulatory values at ODRC in the future – those revenue caps are set in a manner that is consistent with that asset revaluation methodology. Chapter 3 discusses the requirements for consistency if regulatory values are to be reset at their ODRC over time.

Chapter 2

Framework for Analysis

2.1 Introduction

It is assumed that the relevant objective for the Commission when setting revenue caps for electricity transmission businesses is to ensure that economic efficiency is maximised. Accordingly, this chapter first provides an overview of the implications of *economic efficiency* for this task.[7]

One of the important regulatory innovations in the last two decades has been the development of techniques to overcome the lack of incentive that regulated entities may have for minimising cost under more traditional regulatory arrangements. The two asset revaluation methodologies assessed in this report effectively imply the selection of one of either two schools of thought as to how best to encourage efficient production. Accordingly, the costs and benefits of each of these approaches are discussed below.

As well as innovative measures to encourage cost minimisation, the last two decades has witnessed the development of forms of regulation that harness regulated entities' commercial incentives to deliver other socially beneficial outcomes. The other outcomes that may be relevant to the relative merits of the alternative asset valuation methodologies are the setting of efficient prices and the decision to invest in the most appropriate technology and at the most appropriate time. Accordingly, the approaches to these issues are also discussed below.

The provisions of the National Electricity Code embody a regulatory tool for achieving some of the objectives discussed above – namely, the 'regulatory test', and also preclude the use of one of the tools – namely, using incentives to encourage efficient pricing. Accordingly, the relevant provisions of the Code, and their implications of the relative merits of the two asset revaluation methodologies are also discussed below.

2.2 Objectives of Price Regulation – Economic Efficiency

Economic efficiency, in general terms, refers to a condition under which society's limited resources are used such that the benefit to society is maximised, for a given distribution of wealth. While the conditions for economic efficiency can be expressed in terms of three general outcomes,[8] the more relevant (interrelated) implications of economic efficiency for the matter at hand include the following:

[7] It is noted that Chapter 6 of the National Electricity Code – and the Code Objectives set out in Chapter 1.4 – may imply that considerations other than economic efficiency may also be relevant. However, consistent with the brief, this report addresses only the efficiency-related issues associated with the different methodologies for updating regulatory asset values.

[8] The more general conditions for economic efficiency are:

- the mix of goods and services that an economy produces reflects the relative value that society places on those goods and services given the extent of society's resources required to produce the respective goods and services (allocative efficiency);
- firms produce the goods and services for the minimum cost, which implies that the lowest-cost combination of society's resources (typically defined generically as land, labour and capital) is used, and the best technology is employed (productive or technical efficiency); and

- *Efficient pricing* – prices signal to customers the relative scarcity of 'resources' used to provide network services (including prices reflecting cost-efficient provision of service). This condition ensures customers' decisions about whether to connect to the network or to use the system at a particular time are also socially optimal decisions;
- *Efficient investment* – investors must have the incentive to invest in long-lived assets that will be required to ensure that the service continues to be provided at the desired service levels over the long term; and
- *Efficient production* – the service delivered by the network (ie energy of a particular reliability at a particular point) is produced in the least cost manner. This requires the selection of the cost-minimising technology for providing the service given all of the available options, and the construction and ongoing operation and maintenance of the asset in a least-cost manner.

The *first condition* implies that the regulatory regime should minimise the opportunity for the provider to set unnecessarily high prices (and making unnecessarily high returns) that may otherwise arise from its market power. Thus this condition effectively places an upper bound on earnings. It also has implications for the structure of tariffs. As electricity transmission is characterised by economies of scale and scope, setting prices at the efficient level may not permit the recovery of all costs, and so additional cost recovery may be required. Given the need to allow all costs to be recovered (resulting from the second condition, and discussed further below), efficiency requires that tariffs be structured to recover the residual in a manner that has the least impact on the pattern of demand.

The derivation of the most efficient prices is a demanding task, and one for which regulators are not well equipped. A more recent innovation in regulatory practice has been to provide regulated entities with the flexibility to set charges, and to design regulatory arrangements to encourage efficient price setting. This issue is discussed in section 2.4. However, the National Electricity Code limits the applicability of such arrangements for transmission pricing – as discussed in section 2.5.

The *second condition* requires that investors expect to make sufficient returns from the regulated business to recover the costs – including the opportunity cost of the funds tied up in the business, adjusted for risk – from investing in the regulated business, and so effectively places a lower bound on earnings. Taken together, the first and second conditions would be met from a set of regulatory arrangements that provide investors with an expectation of making a reasonable (risk adjusted) return on their investments and a return of that investment over the life of the relevant assets.

While the outcome implied by the *third condition* – ensuring that the regulated services are provided at least-cost – is straightforward in principle, achieving such an outcome in practice is complex. The selection between the two asset revaluation methodologies effectively implies a choice between the different approaches that exist for encouraging cost efficiency. Accordingly, the two methods are discussed next.

- the mix of goods and services produced, and the production processes employed by firms, change over time in response to changes in tastes, technology and other factors – that is, so that allocative and productive efficiency is maintained at each point in time (dynamic efficiency).

2.3 Encouraging Efficient Production

It is now widely understood that regulatory arrangements that provide a high degree of certainty over the recovery of costs incurred – consistent with the second condition discussed above – also provide less incentive for the firm to seek to minimise costs and, indeed, can provide the perverse incentive to over-spend. The US system of 'rate of return regulation' is the most obvious example of regulatory arrangements that provide poor incentives to minimise cost. The US institutional arrangements have generally allowed firms or the regulator to seek adjustments to prices whenever costs or revenues move such that the allowed rate of return is breached.

It is also widely accepted that the regulator is in a poor position to judge whether a particular project or technology or organisational structure and associated staffing levels represent efficient production. The regulated entity's knowledge of such matters outweighs vastly that of the regulator, and so attempts by a regulator to disallow perceived inefficiencies are unlikely to be effective.

The presence of both information asymmetry between the regulated entity and the regulator over what is efficient practice, coupled with the poor incentive properties of regulatory arrangements that promise a high degree of certainty of cost recovery, has lead to the development of alternative forms of regulation that overcome these deficiencies. The two different forms that are relevant to this report are *price cap regulation* and *external benchmark regulation*, which are discussed in turn below.

Price Cap Regulation

Price cap regulation is one of the manifestations of incentive regulation, the essence of which is that the regulatory regime is designed to provide firms with incentives that align its private interests with social interests – that is, to act efficiently. Given these incentives, the firm's actual behaviour can be assumed to be efficient – or at least to converge towards efficiency over time – implying that observations of the firm's actual behaviour can provide information that can be relied upon for regulatory purposes.

Thus, the underlying philosophy of incentive regulation is – in effect – to bribe the regulated entity to act in a manner that is efficient and so reveal this to the regulator, and then to use the information gained to improve the efficiency of the regulatory process.

With respect to achieving cost efficiency, the most common method for aligning interests is through the use of a price cap. Under a price cap, prices are set independently of cost for a period, which implies that the regulated entity can increase its returns by reducing its expenditure (including by meeting its service obligations using a different technology).[9] A more recent innovation in the use of price cap regulation is the introduction of a carry-over of some of the benefit from efficiency gains made in one regulatory period to the next. If properly designed, the carry-over of efficiency benefits can eliminate any reduction in the incentive to pursue efficiencies that may otherwise exist towards the end of a regulatory period.[10] The potential rewards from the pursuit of efficiency gains under price cap / efficiency carry-over regulation – and hence the strength of the incentive to make such gains – is then a function of the length of the period between price reviews.

There are two methods that can be used to set the rate of change of prices over the regulatory period. The first method – and one used in the UK and in Australia – is to forecast expenses and demand growth over the period, and set the price path such that the expected revenue under the price control equates with the expected cost of providing the services (both in discounted terms). The second method – and which is widely used in US price cap plans – is to set the rate of change in prices with reference to a proxy for expected future productivity increase for the industry, for which long term historical productivity growth is generally used as the proxy.

Over time, it would be expected that such incentives would lead to the firms' expenditure levels reflecting efficient levels, and reflecting new technologies and techniques as they become available. The use of such incentive arrangements have a number of benefits for all parties involved in the regulatory process.

- The presence of the incentive arrangements would permit the *regulator* to infer that a firm's actual expenditure level at the end of a regulatory period is efficient, and to use that expenditure level as a starting point when setting price caps for the next regulatory period. Accordingly, the regulator could satisfy it statutory obligations without the need to second-guess a firm's operational decisions – over which the regulated entity has substantial informational advantages relative to the regulator.
- The use of incentive arrangements should encourage efficiency gains that otherwise would not have been achieved. *Customers* would benefit as these gains are passed through into lower prices over the medium term.
- *Regulated entities* have the opportunity to make additional returns from above-expected performance. The regulator's use of incentive arrangements to generate outcomes like cost-efficiency would also avoid the potential need for the regulated entity to justify specific operational decisions to the regulator.

An important question to be addressed when designing the price cap regime is the strength or power of the incentive for cost reductions that is created. The importance of this issue derives from the fact that as the strength of the incentive to minimise cost rises, the level of certainty over the recovery of costs incurred – or the level of insurance provided by the regulatory regime – falls.

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9 It was also recognised that prices could more credibly be set independent of cost for a period if prices where adjusted for inflation (thus removing a substantial risk to investors in times of inflation uncertainty) and if an offset were made for expected future productivity gains (the X factor). Accordingly, price cap regulation is also commonly referred to as CPI-X regulation.

10 The design of such an efficiency carry-over mechanism is described in some detail in: ESC 2002, *Review of Gas Access Arrangements: Final Decision*, October.

Price cap regulation works by exposing regulated entities to the profit consequences caused by differences between their actual cost incurred in providing the regulated services and the cost assumed in the price cap *for a period*. It is inevitable that a firm's actual cost will diverge from that assumed in the price cap. The higher the strength of the incentive, the longer the period of time that the provider would either retain the benefit – or bear the shortfall – associated with a difference between its actual cost and that assumed in the price cap. Thus, stronger incentives provided to reduce costs, the greater the risk that either the entity is unable to continue to finance its activities (thus violating condition two above), or that profits reach an unacceptably high level.[11]

Accordingly, the combination of the need to secure an adequate level of investment in long-lived assets and also to ensure that customers are protected from monopoly pricing is likely to impose a constraint on the strength of the incentives for cost-efficiency that reasonably (and credibly) can be imposed.

External Benchmark Regulation

An alternative approach to using a price cap to overcome asymmetric information and incentive problems is to attempt to use a model to predict the efficient cost of undertaking the relevant activity. External benchmarking uses cost information from a large number of regulated entities, together with the information about each of the networks to adjust for factors that may cause costs to differ across networks. The outcome of such a methodology is that the regulated price (or at least the starting price) is predicted, based solely upon information that is external to the regulated entity (or at least in principle).

Numerous techniques exist for attempting to predict the efficient cost of providing regulated services; the categories identified in the recent paper to the Utility Regulators Forum were as follows:[12]

- Frontier methods – which included Data Envelopment Analysis and Stochastic Frontier Analysis;
- Econometric Benchmarking; and
- Engineering economic analysis.

Continuously updating the regulatory value of the electricity transmission assets to an estimate of their ODRC value corresponds to the latter methodology – the engineering economic analysis.

[11] While it is possible to exclude the regulated entity from some of the events that may affect future profitability through the use of pass-through clauses or a specific correction factor in a price cap, these mechanisms could only apply to a very narrow class of events. This is because many of the events (or the consequences thereof) that may cause cost to change are likely to be partly within the control of the regulated entity, and so seeking to insulate the provider from this risk would undermine the incentives for efficiency that the price cap regime was intended to generate in the first place. Extending pass throughs to a broader class of events will expand the cost of administering the price cap plan.

[12] Farrier Swier Consulting, Comparison of Building Blocks and Index-Based Approaches, Report to the Utility Regulators Forum, June 2002, pp.32-33.

The ability to use external benchmark models to set regulated charges is dependent upon a comprehensive and reliable set of information on the costs and relevant cost-related conditions of networks and a model that can predict costs to a level of accuracy that would make the methodology credible. In practice, however, it may be necessary to 'fit' a model to a particular regulated, which may imply that it may not be possible for the regulated charges to be completely independent of the decisions of the regulated entity. This is a particular issue for the 'engineering economic analysis' method, and is discussed further in section 3.1.

While not normally explicit in the use of external benchmark regulation, it would be open for the rate of change in the regulated prices over the regulatory period to reflect a proxy for industry-wide productivity growth.

Regarding the power or strength of the incentive to reduce cost (and level of insurance), the use of an external benchmark model to predict the total cost of an activity would imply a 'no cost insurance' model.

Regulatory Methods Compared

There are a number of distinguishing features between the use of a price cap methodology and external benchmark model.

- First, the price cap method uses actual costs as a starting point for the future price path, whereas the external benchmark approach bases the initial prices on predicted efficient cost.
- Secondly, the price cap method permits a selection of the strength of incentives to reduce cost (or degree of 'cost insurance'), which is choses through the selection of the length of the regulatory period. In contrast, prices under the external benchmark model would not insulate the provider from any changes in cost.

For both methods, prices over the term of a regulatory period could be set using a proxy for expected future industry-wide productivity growth if desired.

2.4 Other Incentive Arrangements

The use of price caps to encourage cost efficiency is just one of the regulatory tools falling under the heading of incentive regulation that can be used to align a regulated entity's private interests with the social interests, and so improve the outcomes from regulation. An outline of some of the other measures is as follows.

Efficient Tariff Structures and efficient response to demand growth

Given the existence of economies of scale and scope in electricity transmission, a residual amount of costs in excess of the marginal cost of providing the service needs to be recovered from customers. Efficiency requires that this residual be recovered in a manner that least distorts usage patterns. However, the derivation of an efficient price requires account to be taken of the demand sensitivities of different customers and to different methods of charging. Unfortunately, the regulator is not well positioned to undertake this assessment.

A recent trend in regulation is to delegate the decision over the structure of prices to the regulated entity (within an overall cap), and to provide incentives for the entity to set efficient prices. Within a regulatory period, the specific form of the control over prices affects the payoffs that may be associated with tariff rebalancing, and hence is the mechanism through which the incentive to set efficient prices can be provided.

Similarly, the form of price control also determines the incremental revenue that a provider will receive from additional load growth (as well as the loss it suffers from a loss of existing load), and so will affect the provider's decisions in relation to expansions to the system to meet new load growth. An important choice for the network provider may be how to respond to a possible growth in demand, there is a high degree of uncertainty about that future growth. Typically, there are a range of means to meet that growth, from purchasing demand management, to installing different types of transmission assets. In the presence of such uncertainty, responses that provide a degree of flexibility to respond to changes in future demand (such as demand management options, or the construction of a smaller capacity upgrade) are likely to have an additional benefit to the regulatory regime,[13] which implies that a simple comparison of the discounted cost (or net benefits) of the alternatives may not deliver the most efficient choice of response. Ideally, the incentive arrangements should lead the provider also taking account of the value of flexibility when selecting between the alternative means of responding to demand growth.

The choice of revaluation methodology may also have an impact on the incentives both to set efficient prices and to select the most efficient means of responding to demand growth. Under a price cap approach, the provider is only exposed to the consequences of events that occur during the price control period, and hence would only be expected to take account of such events when designing price structures and selecting between different means of meeting demand growth. In contrast, revaluing assets at a level consistent with that required to meet outturn demand (ie the ODRC revaluation methodology) would have the effect of exposing the regulated entity to the consequences of such events in all future periods.

The practical importance of providing such an incentive is an empirical issue. In addition, its relevance depends centrally on the length of the regulatory period – the longer the period, the more events the provider would be expected to take into account when making decisions. Thus again, better incentives to take account of future events would be provided by extending the length of price control periods.

However, we do not think that the objectives of providing an incentive to set efficient prices and to select the most efficient means of responding to uncertain demand growth are of central importance for electricity given the other regulatory tools and constraints in the National Electricity Code, which are discussed next.

[13] The characteristic of a project to allow the cost incurred to be varied to reflect observed demand (or other factors) is often terms a real option.

2.5 Implications of the National Electricity Code

The National Electricity Code contains two mechanisms that may reduce the requirements for additional tools to achieve the objectives set out above, and hence reduce the range of issues for which the choice of the asset revaluation methodology is relevant. These two mechanisms are the 'regulatory test' and the determination of price structures.

Regulatory Test

The National Electricity Code requires that new regulated investment satisfy an up-front 'regulatory test' to ensure that the benefits of undertaking the investment outweigh the costs. The 'regulatory test' is applied at a time prior to investment being undertaken (and expenditure sunk), and has as its objective the ranking of the desirability of a particular project against possible alternatives (including the alternative of doing nothing, or doing the same thing at a different time). The Commission has a role in determining any disputes about the application of the test.

The existence of the requirement for the regulatory test implies that a new project would already have to satisfy a formal test of whether it is the most efficient means of meeting demand growth. Given the existence of such regulatory requirement, the importance of incentive arrangements for delivering efficient project choices is lessened.

Price Control and Tariff Structure

The National Electricity Code specifies in detail the approach to cost allocation and tariff design for the pricing of transmission services. The implication is that regulated transmission businesses have practically no discretion over the setting of tariffs.

The existence of a prescribed methodology for cost allocation and tariff design implies that incentive arrangements to encourage efficient price setting would not have a role to play.

Chapter 3

Asset Valuation Methodologies to be Assessed

3.1 The Optimised Depreciation Replacement Cost Valuation Methodology

Introduction

Updating the regulatory asset base of regulated transmission assets to a new estimate of the ODRC value over time would imply that the regulated charges – or tariffs charges – would be set independently of actual costs incurred over the previous or any other regulatory period. In order to assess the relative merits of such an approach, the issues associated with its application are:

- the conceptual underpinnings of the ODRC valuation;
- the theoretical limitations to the continued reapplication of a properly-calculated ODRC value;
- the practical application of the ODRC valuation methodology to date;
- areas where the estimation of ODRC valuations may need to be refined if assets are to be re-valued at ODRC over time; and
- the implications of ODRC valuations for the other inputs required to set regulated charges.

Conceptually-Correct ODRC Value

The objective of an ODRC valuation is to estimate the maximum price that a person would be willing to pay for an existing asset, given the alternative of constructing a new asset.[14] In effect, it is an estimate of the price that an asset would sell for if that asset was traded in a liquid second-hand market (like used cars). In such a market, the value for the existing asset would reflect the cost of a new – and optimum – asset, but would also reflect all of the differences in the forward-looking service potential and costs of associated with the existing asset, compared to the new asset (all discounted to a present value or cost).

- It is important to understand that an ODRC valuation seeks to replicate the second-hand value of assets, *on the assumption that such a market existed*. In practice, the presence of substantial sunk costs and economies of scale and scope implies that such a market does not exist – indeed, if a liquid second hand market for regulated assets did exist, then there would be no rationale for regulation. Moreover, the reference to the service potential is a reference to the potential generated for society, rather than the service potential that necessarily could be captured by the asset owner. The degree of structural separation in the Australian electricity industry implies that it is not always possible for the provider of an asset to capture all of the benefits created.

[14] The Commission has discussed the theoretical foundations of the ODRC valuation in similar terms: Australian Competition and Consumer Commission, Draft Statement of Principles for the Regulation of Transmission Revenues, May 1999, pp.39-40.

A straightforward implication is that the ODRC value provides an estimate of the value that existing assets (that is, those that are inputs to production) would have in a market where the price was set at the level consistent with the price that would be charged by a hypothetical (efficient) new entrant (that is, assuming a perfectly contestable market). The logic for this is follows.

- The hypothetical (efficient) new entrant would be expected to set a price that recovered – over the life of its asset – the cost of providing the service with the new, optimum asset (including a competitive, or normal, return on its investment).
- Taking this price as given, the value of the existing asset would be given by its discounted future cash flows – which must deliver a value equal to the cost of the new, optimum asset, but adjusted for any differences in the forward-looking costs and/or service potential associated with the existing asset compared to and new, optimum asset.[15]

It also follows that prices in (long run) competitive equilibrium should be consistent with providing a reasonable return on the cost of the efficient new entrant. Given the relationship between the new entrant's costs and ODRC discussed above, prices in a (long tun) competitive equilibrium will also be consistent with providing a reasonable return on the ODRC value of existing assets.

The conceptually-correct ODRC value has a number of important implications for matters like the impact of excess (or inadequate) service potential on the value.

- Where the existing asset is considered to be overbuilt (ie contains excess capacity), the optimal asset may be sized to meet a lower level of demand. In this case, the old asset may be able to meet the future growth in demand for little or no additional cost, whereas the new 'optimal' asset may require substantial augmentation. The present value of the cost savings of meeting the future growth in demand with the existing asset would be reflected (as a positive addition) to the estimated ODRC value.
- Where an existing asset is considered to have service potential that would not be reflected in the optimal asset, the existing asset may deliver benefits in excess of its optimal replacement. Again, this excess service potential would be reflected (as a positive addition) to the estimated ODRC value.[16]

The steps in the computation – and the inputs – required to derive such an estimate are straightforward, and are as follows:

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15 The price that is expected to be charged by the hypothetical (efficient) new entrant may itself be used to assess the extent to which current pricing practices diverge from those consistent with a contestable market, and hence test whether there is evidence of monopolistic pricing practices. A critical assumption in the estimate of the hypothetical (efficient) new entrant price is the rate at which the entrant would expect to have its capital returned (for a good discussion of the application of the hypothetical new entrant test, see: NERA, The Hypothetical New Entrant Test in the Context of Assessing the Moomba to Sydney Pipeline Prices, A Report to the ACCC, September 2002). However, an assumption about the depreciation rate for the hypothetical (efficient) new entrant is not required to estimate the ODRC value – as knowledge of the present value of the future revenue stream rather than its time profile is all that is required. However, the continued application of the ODRC methodology over time effectively requires the same information, and the issue of the rate of regulatory depreciation that is consistent with the continued use of the ODRC methodology is discussed below.

16 Considered in terms of the hypothetical (efficient) new entrant, if the service offered by the incumbent offers a higher level of service potential than that of the new entrant, then the incumbent should be able to set higher prices than the new entrant, up to the level where the higher prices extracted the additional value that customers obtained from the service.

- First, to identify the asset that would be the optimum replacement (providing the optimum level of service) for the asset in place, taking into account all feasible means of providing the service, and to estimate the (full) cost of construction.

- Secondly, to identify the differences in the forward-looking service potential and costs associated with the existing asset compared to the new (optimal) asset.

- Thirdly, to adjust the estimated cost of the optimal asset to deduct (or add on) the present value of the reduced (or increased) service potential associated with the existing asset, and to deduct (or add on) the present cost of the higher (or lower) forward-looking costs associated with the existing asset compared to the optimal asset.

In analytical terms, the derivation of an ODRC value is then calculated as follows:

$$ODRC_0 = ORC_0 - \sum_{t=1} \frac{Serv_{New,t} - Serv_{Existing,t}}{(1+r)^t} - \sum \frac{Cost_{Existing,t} - Cost_{New,t}}{(1+r)^t}$$

where *ORC* is the cost of the optimal replacement of the existing asset, *r* is the discount rate, *Serv* is the value of the service potential of the relevant asset, and *Cost* is the forward-looking cost (operating and capital) associated with the relevant asset, and it is assumed for simplicity that all costs and benefits are received at the end of each year.

- Implicit in this formulation is that the role of the 'depreciation' step is to adjust for the differences in the forward-looking cost of operating, maintaining and renewing the existing asset compared to the optimal asset, and to adjust for differences in the value of the level of service provided by the existing asset compared to the optimal asset. Thus, the appropriate rate of depreciation is not a simple scaling down of the value to reflect the expired portion of the asset's life.

- Implicit also in this formula is that the use of an ODRC methodology would imply that regulated charges would depend only on the assumed operating expenditure for the optimal asset (that is, charges would be independent of the forecast of the entity's actual operating expenditure). This is because any change in the forecast of the entity's own operating expenditure would be translated into downward adjustment to the estimated ODRC value by an amount that would offset precisely the rise in forecast operating expenditure.

It is clear, however, that the application of the ODRC methodology – if done in a manner consistent with its theoretical underpinnings – requires substantial information, including:

- the optimum replacement for the existing system, which should include consideration of the most efficient means of providing the service given the existing sources of supply and demand, which should include consideration of alternative routes or technologies for providing the optimum level of service;

- an estimate of the cost of replacing the whole system, with this cost estimate taking account of all of the factors that may affect the efficient cost of constructing the relevant system across the whole of the system (for example, typographical factors, and environmental approval requirements);
- a forecast of the future operating and capital cost associated with providing the service using the new asset over the indefinite future, and again with this cost estimate taking account of all of the factors that would affect the efficient cost of providing the service using the optimal system across the whole of the system;
- a forecast of the future operating and capital cost associated with providing the service using the existing asset over the indefinite future; and
- an estimate of the value associated with any differences in the service potential between the existing and optimal asset.

In practice, the application of the ODRC methodology in Australia has fallen well short of the theoretical ideal, and has also involved a number of highly simplifying assumptions, which are discussed below.

First, however, some additional implications of economic principles to the feasibility of a regulatory model that requires the continued reapplication of a conceptually-correct ODRC methodology are discussed.

Theoretical Feasibility of the ODRC Methodology

The discussion above of the conceptually-correct ODRC methodology is the correct means of deriving a regulatory asset base that would be consistent with the market value of a business' assets in a market that is characterised by perfect contestability *at a point in time*, making it impossible in practice to allow for the movement from one optimally configured system to another. Rather, the efficient configuration of an actual system will reflect the fact that it would have been efficient for the networks to be configured to meet demand growth as it had occurred over time. Moreover, the cost associated with providing the level of capacity at any point in time will reflect the fact that actual systems are generally constructed to meet a forecast of future demand growth, rather than just existing demand.

The implications of the *incremental expansion* of the system and *efficient pre-building* – and the possible responses – are discussed in turn below, and then some comments are made on the practicality of the responses to these issues.

Level of Optimisation

As discussed in section 2.3, the incentive for the regulated entity to continue to expand its system to meet the efficient growth in the market relies upon changing the regulatory asset base to reflect the efficient cost of expanding the system to meet that growth in demand. As the transmission networks are generally characterised by economies of scale, scope and/or density, the incremental cost of expanding the actual system from one level of demand to a higher level would always exceed the change in the cost of the optimally configured system.

The implication of re-setting the regulatory asset base at an estimate of its ODRC value is that the provider would always suffer a financial shortfall from meeting growth in demand. One response would be to allow a faster rate of regulatory depreciation – in effect, allowing the provider to recover the difference between the forecast of the actual cost of meeting growth and that reflected in the change in ODRC values from customers in that period. This approach, however, has a number of shortcomings.

- First, the provider's incentive to not meet – or even to actively dissuade – system growth would remain as it would still gain financially *at the margin* by not expanding its system.
- Secondly, the amount of 'new network' that may have to be written off and recovered from customers in the period could be substantial. Moreover, the fact that it would be recovered from existing customers rather than the new customers served may be seen as unreasonable.

The alternative response would be to depart from the hypothetical (efficient) new entrant standard and to factor in an assumption of *incremental expansion* to the configuration of the system. The implication of this is that the optimisation step would be constrained (or, alternatively, that the replacement network would be sub-optimal). The appropriate degree of incremental expansion would be the level that aligned as closely as possible the change in the estimated ODRC value with the incremental cost of expanding the actual system.

The Level of Demand Assumed

The level of demand that the system should be configured to serve when the hypothetical (efficient) new entrant test is applied is straightforward – it is the *current level of demand*.

- If the hypothetical (efficient) new entrant attempted to set prices that recovered the cost associated with meeting a higher level of demand that was expected in the future, then another hypothetical (efficient) new entrant would be able to set lower prices by only seeking to recover the cost associated with serving current demand.
- Likewise, if the hypothetical (efficient) new entrant attempted to set prices that recovered the cost of capacity that had been built some years before to meet current demand, then again another hypothetical (efficient) new entrant would be able to set lower prices by only seeking to recover the cost associated with serving current demand.

However, in practice, transmission investment comes in lumps of capacity – and is generally characterised by economies of scale, scope and density – and it would seldom be efficient to install assets that are configured to meet just the current level of demand. Two observations flow from the need to pre-build capacity.

- First, even if the configuration of the actual system by chance corresponded to the configuration of the optimal system, the assets in the actual system would have needed to be having been built some years before (and so would have a higher cost than the hypothetical optimal system).
- Secondly, if it were assumed that the system could be optimally reconfigured today – but never reconfigured again – the optimal system would be one that was configured to meet future demand.

It follows from both of these observations that using the conceptually-correct ODRC as the regulatory asset base at each point in time would systematically understate the cost of actually providing the service. The two possible responses to this problem would be either to inflate the cost of constructing the optimal system at each point in time to recognise a level of pre-building, or to determine the optimised system as one that is optimal over a normal planning horizon. The latter of these would appear more practicable.

Practicality of the Adjusted-ODRC

The issues discussed above imply that it would be infeasible to reset the regulatory asset base for the electricity transmission assets at a conceptually-correct estimate of their ODRC value (ie the value consistent with the hypothetical (efficient) new entrant) as such a methodology would be expected systematically to understate the cost of providing the transmission services. Rather, two adjustments were proposed, which were:

- to assume a sub-optimal network when estimating the ODRC value to reflect an extent of *incremental construction* in the network; and
- to assume a degree of *pre-building of the network* at any point in time.

Both of these adjustments require further methodological decisions or assumptions. In particular, the adjusted ODRC requires information and decisions on:

- *incremental construction* – a model that generates the efficient *incrementally-expanded system* given the history of the relevant network is required, as well as information on the relevant history; and
- *pre-building* – a decision of the appropriate planning horizon for the purpose of setting an ODRC value is required, as well as the relevant forecasts of demand and sources of supply over that forecast period.

Moreover, at a conceptual level, the adjustment to reflect an incrementally constructed network inevitably implies determining the cost of a network that resembles closely the actual network in existence. A consequence is that the extent to which the regulatory asset base is independent of the decisions of the transmission provider would be reduced.

Practical Application of the ODRC Methodology

The application of the ODRC methodology for electricity transmission in Australia to date has fallen well short of the hypothetical (efficient) new entrant standard and has involved a number of highly simplifying assumptions. However, some of the departures from the hypothetical (efficient) new entrant standard would appear to be responses to the theoretical concerns discussed above with resetting the regulatory asset base at an estimate of its ODRC periodically.

This section provides an overview of the practical application of the ODRC valuation methodology to date, and the refinements that would be required to use ODRC as the basis for continued revaluation of transmission assets. It also comments on the asymmetric information problem inherent in ODRC valuation. Lastly, it discusses a methodologically simpler (but equivalent) approach for re-setting prices based upon the hypothetical (efficient) new entrant standard – which is the use of ORC rather than ODRC as the basis for valuation.

Assumptions adopted in current ODRC Valuations

Regarding the *level of optimisation*, Sinclair Knight Mertz has summarised what it considers to be the standard approach to ODRC valuations for transmission assets in Australia in the following terms.[17]

> Optimisation is a notional exercise. The objective is to determine the optimised transmission system that gives ‘industry best practice’ levels of service, or the same level of service as the existing system, whichever is the lower.
>
> “Brownfield” optimisation follows an incremental approach and not a greenfields approach. With incremental optimisation the existing network is reviewed and configurations, ratings and designs assessed to identify excess redundancy, over-capacity and over-design. It is based on there being no changes to points of supply (generating stations), location of loads, transmission line or cable routes, easements or substation sites. However, existing substations or lines can be amended in layout, or rating, or design, or deleted as appropriate. With greenfields optimisation the entire network would be completely redesigned and all lines and substations re-engineered and potentially relocated.
>
> Incremental optimisation places a limiting constraint on the extent of optimisation. It recognises that there will always be some degree of sub-optimality and reflects to some extent the historical development of the network. It takes a position between a pure economic (greenfield) approach that would lead to significant optimisations and a historical approach (and acceptance of staged construction of assets where economically justified) that would result in virtually no optimisation.
>
> An incremental optimisation methodology has in general been followed for previous electricity asset valuations, thus establishing a precedence for this methodology. Incremental optimisation is considered pragmatic, and has been adopted for this optimisation assessment.

That is, the optimisation step is typically undertaken subject to two constraints:

- *Routes* – that the sources of supply (generators), the delivery point for the transmissions (terminal stations) and the route of each transmission line is fixed at that which exists in practice; and
- *Incremental development* – an assumption is made that the system was expanded in an incremental manner.

In addition, it is also understood that the optimal system is also assumed to be designed to meet forecast demand growth, with a planning horizon of between 10 and 15 years commonly assumed.[18]

Regarding the *depreciation step*, the common method for depreciating the ORC value has been to use standard financial accounting approaches, that is, to scale down the cost of the new asset to take account of the expired age of the asset in place. This contrasts with the required adjustment, which is to adjust the ORC value upwards or downwards to reflect the difference between the forward-looking cost of continuing to run the old and new asset, and upwards or downwards to reflect the difference between the service potential of the old and new asset.

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[17] Sinclair Knight Mertz 2002, *Optimisation Assessment for the SPI PowerNet Network*, April, p 12.

[18] It should be noted that, while the assumption of a degree of ‘sub-optimisation’ and pre-building is relevant where the regulatory value of assets is continually reset to the ODRC value, these assumptions would be invalid for the application of a hypothetical (efficient) new entrant test.

Lastly, the estimates of the *cost of the replacement network* typically have been provided by engineering companies from their own databases, although some estimates of the ODRC value have used previous estimates adjusted for assumed cost inflation, or supplemented with benchmarks drawn from other regulatory decisions or recent examples of actual construction costs. The ODRC estimates that have been undertaken to date would suggest that there is a large degree of statistical uncertainty in the estimates of the cost of replacement assets, a view that often has been expressed as a caveat to independent reviews of ODRC valuations. By way of example, in its report to the Commission on the estimate of the ODRC value for PowerLink, PB Associates commented as follows:[19]

> It should be noted that cost estimating is not an exact science and that costs are different in different areas. Hence results of comparison [when estimating the replacement cost of assets] should be taken as indicative rather than definitive.

Issues for the Continued Application of the ODRC Methodology

If the Commission were to reset the regulatory asset base for transmission providers at an estimate of the ODRC value at defined periods, then it would be necessary for the Commission to provide detailed guidance on the methodology to be adopted to conduct such a valuation. In doing so, the Commission would also need to address any deficiencies in the standard approach to ODRC estimation described above. The criterion against which the application of the methodology should be tested is whether the estimated ODRC value would be likely to provide an unbiased estimate of the cost of providing the regulated transmission service, both over the long term and within each sub-period.

There would appear to be a number of aspects with the current approach that the Commission would need to assess carefully, as well as deficiencies in the standard approach.[20]

First, with respect to the degree of 'sub-optimisation' that is assumed when estimating the ODRC values, the Commission would need to assess whether the methods currently applied are likely to align the change in the ODRC value of a growing system with the efficient cost of expanding the actual systems. The Commission would also need to form a view as to the extent of pre-building that would be considered the efficient level of pre-building. If the ODRC method were to be used for asset revaluation purposes, the methodology and models used to derive the (sub-optimal) network should be made transparent and open to public scrutiny and debate.

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19 PB Associates 2001 *PowerLink Network Asset Valuation Review prepared for ACCC*, April, p 14.

20 The derivation of robust methodology for reapplying the ODRC method over time would be worthy of several reports in itself. Accordingly, only a number of general observations on the issues to be addressed are offered in this report.

Secondly, the sources and method that is used to estimate the cost of constructing the replacement network and the cost of operating that network would also need to be refined and open to public scrutiny and debate. To be sufficiently robust for asset revaluation purposes, the model used to estimate the replacement or operating costs would need to take account of all of the factors that may affect the cost of constructing or operating the optimal system, and be demonstrated to deliver these cost estimates with sufficient degree of precision. To date, there has been little or no public scrutiny of – and hence little informed debate about – the models used by the various engineering firms for estimating the replacement cost of transmission networks and the cost of the operation the networks. Accordingly, it is difficult to conclude that the methodologies currently used are sufficiently reliable to be used to set regulated charges independent of cost.

Thirdly, while it may be possible to continue to adopt the simple approach to the depreciation step – that is, the use of a financial accounting approach to depreciation – the Commission would need to be careful as to how it determined the new operating expenditure forecasts.[21] In particular, if the capital-related element of cost is set according to an external benchmark but operating expenses are set with reference to the firm's actual operating expenditure, then the firm would have two obvious incentives, which are to:

- skew its choice of technology towards high operating cost / capital cost equipment, the most obvious example of which would be to keep old assets in service longer than would be efficient; and
- to seek to classify as much expenditure as possible as operating expenditure rather than capital expenditure (which is a bias that would be consistent with financial accounting guidelines).

The only practicable response to both of these concerns with the operating expenditure forecasts would be to also use an external benchmark to determine operating expenditure forecasts – although the external benchmark should reflect the network actually in place. However, if an external benchmark for operating expenditure is required regardless, the simple financial accounting method for the depreciation step would appear to offer no advantages – it would appear more sensible to derive the external benchmark for operating expenditure to be consistent with the replacement asset, and to make the correct adjustment for depreciation.

Lastly, there are a number of difficult issues that the Commission would need to settle in order for an ODRC revaluation methodology to be applied, such as how it would deal with matters such as changing environmental standards.

The resolution of the issues discussed above and development of a sufficiently robust methodology would be expected to be a substantial task for the Commission.

Asymmetric Information Problem

A further consideration for the Commission when assessing the relative merits of the two methodologies for updating assets over time is the extent to which the application of the relevant methodology is dependent upon information that is held by the regulated entity.

[21] It is not completely clear whether the use of the financial accounting approach to depreciation would be sustainable over time in the face of changing operating expenditure requirements.

As discussed in Chapter 2, the development of external benchmark models – like engineering cost estimation models – was driven by a concern to overcome the asymmetry of information between the regulator and regulated entity. However, the practical application of the ODRC methodology as discussed above implies that the Commission would be dependent upon information that is held by the regulated entity. Some of these examples are as follows.

- First, the design of the replacement system would require load flow studies for the relevant system, which in turn requires assumptions about current and future (normalised) flows into and out of the relevant network. For most of the regulated transmission entities, the cost-effective gathering and analysis of this information could be undertaken only by the transmission entity.
- Secondly, the estimation of the cost of constructing the replacement network requires knowledge and adjustments for location network conditions. While in theory anyone could 'walk the route', the transmission entity would have an advantage in gathering and analysing this information.

To date, the estimates of the ODRC value of regulated assets in both the electricity and gas industries have been produced by the owners of the regulated assets (or their representatives), and the regulators' analyses typically has been limited to a desk-top analysis of the main assumptions reflected in those estimates. If regulatory values for regulated electricity transmission assets are to be reset at their estimated ODRC value over time, it would be expected that the Commission would need to take on a more active role in the derivation of the ODRC estimates.

An Alternative Methodology – ORC-Based Prices

To the extent that the Commission intended to use the engineering cost model approach to determine regulated charges into the future, a preferable approach may be to set charges based upon a model that sets charges with reference to the optimised replacement cost of the system (referred to below as the ORC approach), rather than with reference to the depreciated value. Such an approach would mirror the approach that is used to set access charges in telecommunications.

If applied correctly and consistently, both the ORC and the ODRC methodologies would deliver the same regulated charges.[22] However, the ORC methodology may offer a number of practical advantages. First, the use of the ORC methodology would obviate the need to forecast the costs of continuing to operate the existing system – and make it obvious that the assumptions about the forward-looking cost of operating and renewing the old asset would not have an impact on regulated charges if the ODRC methodology is applied correctly. More importantly, if the ORC approach is applied, regulators would be able to draw upon the body of knowledge with respect to the methodological issues associated with reapplying an engineering cost-based asset valuation over time that has developed in the telecommunications context.

[22] The equality between the ORC and ODRC methodologies requires the depreciation step of the ODRC valuation to adjust for the differences in the forward-looking cost of operating the old and replacement assets. If a financial accounting approach to depreciation is undertaken, one of the methodologies may provide higher regulated charges – although it is an empirical question as to which would be higher.

Consistency Requirements for the Application of the ODRC Methodology

The objective of setting regulated charges that provide an opportunity to recover efficient cost (as discussed in Chapter 2) has two important implications for the other inputs that are used with an ODRC value.

First, the assumptions for operating and capital expenditure and the useful lives of assets would need to reflect those consistent with the old (or existing) asset. This reflects the fact that the depreciation step in the ODRC valuation would already have reduced the value of the regulatory asset base on account of the higher forward-looking cost of operating and renewing the existing asset and shorter useful lives of existing assets.[23]

Secondly, the regulatory depreciation allowance would need to reflect an unbiased estimate of the forecast change in the ODRC value for the network over the regulatory period less the capital expenditure forecast for the period. This is necessary to ensure that the expected present value of future cash flow equates to the regulatory asset base at the commencement of the regulatory period. That is, the regulatory depreciation allowance would need to be calculated as:

$$\sum_{t=1}^{T} Reg\ Dep_t = \left(ODRC_T - ODRC_0\right) - \sum_{t=1}^{T} Capex_t$$

where the regulatory period is T years in length.

The calculation of the appropriate regulatory depreciation allowance, therefore, requires all of the assumptions required to derive the ODRC value at the commencement of the period, but projected out to the end of the regulatory period. Important assumptions include the trend in the cost of replacing the relevant assets, and assumptions about the likelihood of parts of the system becoming redundant over the period.

An implication of the ODRC revaluation methodology is that future regulated charges would be constrained to follow a unique time profile – in effect, (almost) mirroring the prices that would be charged by an efficient new entrant. A second implication is that the derivation of the regulatory depreciation allowance is likely to be controversial as any errors in its estimation would imply a windfall gain or loss to the regulated entity.

23 As discussed already above, the assumptions about the cost of operating, maintaining and renewing the existing asset should have no affect on regulated charges if the ODRC value is estimated correctly. This reflects the fact that a rise in the cost of operating, maintaining and renewing the old asset compared to the new would imply a commensurate reduction in the ODRC value.

3.2 The Roll-Forward Methodology

Introduction

Under the roll-forward methodology, the regulatory asset base at the commencement of a regulatory period would be calculated as the opening regulatory asset base at the commencement of the previous regulatory period, plus the actual capital expenditure over the period, less regulatory depreciation (and disposals). As the regulatory asset base is adjusted for actual capital expenditure and actual funds returned to investors implies that the future prices would be based upon the actual cost incurred in providing the service.

In contrast to the application of the ODRC revaluation methodology, the application of the roll-forward methodology is relatively straightforward. However, for completeness, the main features of the methodology are summarised below. First, the formula for updating the methodology is discussed, followed by a discussion of the model's consistency with the use of price cap regulation. Lastly, the implications of the roll-forward model for the other inputs required to set regulated charges is noted.

Application of the Roll-Forward Methodology

Under a price cap regulatory regime, the regulatory asset base need only be calculated at the commencement of each regulatory period, which is assumed in the discussion below.

The formula for deriving the opening regulatory asset base is as follows:

$$RAB_{Opening,T+1} = RAB_{Opening,0} + \sum_{t=1}^{T} Capex_t - \sum_{t=1}^{T} Deprec_t$$

where the previous regulatory period was T years in length. If the return on assets that was assumed in regulated charges for the previous period was defined in real terms, then this formula holds if the values are set in constant price terms.

The opening regulatory asset base at the commencement of the previous period (year 1) would have been settled in the previous regulatory period, and the capital expenditure for each year except for the last year of the regulatory period would be observable from the company's regulatory accounts. The capital expenditure for the last year would not be observable if prices are set in advance of the next regulatory period, as the final decision would be made part way through the last year.

Accordingly, the only matters upon which a decision is required is:

- how depreciation should be measured; and
- the assumption about the last year of the previous regulatory period.

Regarding depreciation, there are two possible options, which are to:

- use the depreciation methodology and lives assumed in the previous regulatory period to derive the depreciation allowance, reflecting the actual mix of capital expenditure over the period; or

- use the dollar allowance (adjusted for inflation) that was included in regulated charges for the previous period.

The application of either methodology is feasible, although some regulators have relied upon the latter approach because of its simplicity and greater consistency with the 'financial maintenance concept' (which is discussed in section 4.5).[24]

Regarding the assumption to be made about capital expenditure in the last year, again a range of simple assumptions are possible. However, it has been noted that merely assuming that the outturn capital expenditure is equal to the original forecast would have the most desirable incentive properties if a carry-over of part of the benefits of efficiency gains in the previous period is provided.[25]

Use of Price Cap Regulation

As discussed in section 2.3, if prices were changed to reflect changes in the costs incurred in providing the regulated service frequently (or able to be reset to reflect cost as soon as a discrepancy between price and cost had occurred), the regulated entity would have little incentive to minimise cost. This is because the consequences of inefficiency would be largely borne by customers. The roll-forward methodology would be a feature of such a regulatory regime.

However, price cap regulation is also compatible with the roll-forward revaluation methodology. In particular, by setting prices independent of cost for a period, the provider would retain the benefits from reducing costs (or minimising any increase in cost) for the period of the price cap. Moreover, the price cap could be combined with a carry-over of part of the efficiency gains made during the regulatory period in order to ensure that the benefits from making cost reductions is constant throughout the regulatory period.

Under price cap regulation, the rolled-forward regulatory asset base would be used to set prices at the commencement of a new regulatory period, but then have no effect on price levels until prices were reset at the next periodic price review. As also noted in section 2.3, the size of the incentive to reduce costs would be determined by the length of time between such periodic price reviews.

Administrative Costs

The setting of regulated charges inevitably will be administratively costly for both regulators and regulated entities.

However, with the greater use of incentive arrangements discussed in Chapter 2, the administrative costs of updating a regulatory asset base to the start of a new regulatory period can be reduced substantially – to merely ensuring that reliable information on actual costs incurred is kept (which would be required for any methodology).

[24] See, for example, Essential Services Commission (Victoria), Review of Gas Access Arrangement – Final Decision, October 2002, p.132.

[25] Essential Services Commission (SA), Electricity Distribution Price Review: Efficiency Carryover Mechanism, Working Conclusions, April 2003, p.30.

Establishing the new price path (or X factor) under the current approach in Australian of basing this on internally generated forecasts can bring with it significant administrative costs, arising in large part because the regulated entities stand to make windfall gains if the forecasts are biased towards setting higher prices. However, it would be open to the Commission over time to make more use of external productivity estimates (rather than internally generated forecasts) to set the trajectory of price paths between regulatory periods. The greater use of objective measures to set price paths would be likely to reduce the administrative costs of implementing price cap regulation.

Consistency Requirements for the Application of the Rolled-Forward Approach

The use of the roll-forward methodology would permit a range of approaches to be used to determine the opening regulatory asset base for a network in existence, and not be limited to valuing the assets using the ODRC methodology, the only constraint being that the value of existing assets be rolled-forward mechanically thereafter. In addition, to the extent that the Commission considered it appropriate to value pre-existing assets at a value equivalent with the price that would be charged by a hypothetical (efficient) new entrant, this valuation would be feasible. Moreover, the adjustments to the conceptually-correct ODRC estimate (ie assumption of incremental construction and pre-building) discussed in section 3.1 are only required if assets are to be reset at an externally estimated value over time. If the value is to be set once and then rolled-forward, the unadjusted-ODRC value would be feasible.

The only constraint on regulatory depreciation is that the regulated entity have its capital returned at a sufficiently fast rate that it is expected to have returned (through regulatory depreciation) the whole of the value of its investment over the life of the asset, taking into account such matters as possible competition in the future. Subject to this lower bound, any regulatory depreciation profile is feasible.

Lastly, as with the ODRC methodology, the operating and capital expenditure assumptions that are used to derive revenue benchmarks should reflect the cost of operating the system in place (that is, the existing asset rather than any notional optimal asset).

3.3 Key Differences Between the Options

The discussion above has identified the following matters upon which the two asset valuation methodologies differ:

- the strength of incentives provided to reduce cost and, related to this, the level of certainty over the recovery of costs incurred;
- the level of average prices over the period and the permitted time profiles for tariffs; and
- level of administrative costs expected from applying each of the methodologies.

The assessment of these different factors is set out in Chapter 4. First, however, the differences between the separate concepts of ODRC revaluation and ‘regulatory stranding’ and ‘prudence tests’ are discussed.

3.4 Related Measures – 'Regulatory Stranding' and 'Prudence Tests'

There are two other regulatory tools that have featured in discussions of the methodology for updating a regulatory asset base, which will be referred to in this report as 'regulatory stranding' and undertaking a 'prudence test'. In order to avoid confusion, the differences between each of these regulatory tools and updating a regulatory value at its estimated ODRC value are discussed in this section. It should be noted that both of these measures are incompatible with an approach whereby the regulatory asset base is reset at its estimated ODRC value periodically, but may be used as a complement if the regulatory value is updated (or rolled-forward) to reflect actual events over the regulatory period.

Regulatory Stranding

'Regulatory stranding' is taken as asking whether any of the elements of a network have turned out to be excess to requirements, and adjusting the regulatory values for the specific assets downward, if the regulator is not compensating for the reduction in asset value through an increased regulatory depreciation allowance (and regulated charges).[26] It would be expected that 'stranded assets' may be readmitted to the regulatory asset base at some time in the future if they subsequently become used; however, the loss of income over the intervening period would be borne by the provider.

Some of the distinguishing features of 'regulatory stranding' assumed in this report are that:[27]

- the assessment of whether an asset should be 'stranded' would be made on the basis of a measure of utilisation of the asset – asset values would not be adjusted downwards to reflect a reduction in the cost of replacing the relevant asset;
- the judgment of the need for an asset would be expected to be made for either individual network elements or sub-networks, rather than comparing the system in place to the system that would be constructed by the hypothetical (efficient) new entrant;
- the assessment of whether an asset should be 'stranded' is an *ex post* test, that is, a judgment on the efficiency of a network element in light of outturn market outcomes; and
- the financial implications of asset stranding for the regulated entity would be asymmetric, that is, assets either would remain at their (implicit) regulatory value, or be re-valued downwards.

[26] 'Regulatory stranding' can be distinguished from what may be termed economic redundancy, the latter of which would occur where the existence of competing energy sources and/or a decline in demand may imply that the provider is unable to set prices that recover its revenue requirement. While such a form of stranding would not be imposed at the time by the regulator, the potential for economic redundancy should be anticipated in decisions, in particular, about the rate of regulatory depreciation that is permitted. The issues associated with the optimal rate of regulatory depreciation are discussed in section 4.3.

[27] This definition of 'regulatory stranding' is broadly consistent with what the National Gas Code refers to as 'redundant capital' (National Third Party Access Code for Natural Gas Pipeline Systems, sections 8.27-8.29).

Clearly, the implementation of a policy on 'regulatory stranding' would require a number of conceptual issues to be resolved, which include how the need for a particular network element is to be determined (and whether a form of threshold is required to be crossed before an asset is declared to be stranded), the extent of the value of an asset that is removed, and how what may be efficient pre-building of assets is to be treated.

Prudence Test

In contrast, what will be referred to as a 'prudence test' is taken to mean that the regulator would undertake its own assessment of the appropriateness of investment, and exclude assets from the regulatory asset base that did not pass the test. While the term 'prudence' is used, it is envisaged that the regulator would assess the efficiency of the relevant project or projects, potentially assessing such matters as:

- whether it was efficient for the relevant service potential to be created (that is, valued by its customers at more than its cost);
- whether the project was the optimal means of providing the service potential, given alternative technologies for providing the service; and
- whether the project was constructed in a least-cost manner.

The Commission's Regulatory Test (discussed in section 2.5) effectively requires a 'prudence test' as described above with respect to new augmentation projects, and is included for all projects (ie renewal and augmentations) in the Commission's existing Draft Regulatory Principles.[28] This description of the 'prudence test' is also broadly consistent with the tests required for capital and operating expenditure in the National Gas Code.[29]

A variety of administrative approaches to applying such a test could be adopted, ranging from undertaking an audit of the systems and procedures adopted by the relevant utility, to assessing the efficiency of individual projects (in turn, for which a range of different approaches could be adopted). Some of the distinguishing features of 'prudence' assessments assumed in this report include following:

- the test would be undertaken at the time when capital expenditure is first considered for being rolled-in to the provider's regulatory asset base (ie the next price review) and not at some time in the future; and
- the test would take account only of information available at the time that the project took place – and so utilise only information that was available to the provider.

Regulatory Tools Compared

Following from the discussion above, the key differences between the concepts of resetting the regulatory asset base at an estimate of its ODRC value, regulatory stranding and prudence tests are as follows:

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28 Australian Competition and Consumer Commission, Draft Statement of Principles for the Regulation of Transmission Revenues, May 1999, pp.56-57.

29 National Third Party Access Code for Natural Gas Pipeline Systems, sections 8.16, 8.37.

- *Level of optimisation* – the new ODRC value should reflect (in principle) the cost of a fully optimised system at any point in time, that is, taking into account different routes for transmission lines, siting of terminal stations, etc. In contrast, ‘regulatory stranding’ merely asks whether the asset that has been installed is has turned out to be excess to requirements, whereas the prudence test asks whether the asset to be installed is considered (ex ante) to be excess to requirements.
- *Financial effect* – re-setting a regulatory asset base at an estimate of its ODRC value could have a positive or negative impact on the provider, with the direction of the impact depending on whether the forecast of the period-end ODRC value that was assumed in existing tariffs over or understated the value. In contrast, ‘regulatory stranding’ could have only a negative effect on a provider. In particular, even though an asset could be readmitted into the regulatory asset base if it subsequently became sufficiently utilised, the opportunity cost of funds associated with that investment would have been foregone over the intervening period. Similarly, the effect of a prudence test could only be negative, although the fact that the test is an ex ante test – that is, relying on only the information available to the provider at the time of making the investment – implies that it would be reasonable to expect that the vast majority of projects would pass the test.

Chapter 4
Assessment

4.1 Introduction

This chapter considers the relative merits of the alternative asset revaluation methodologies, focussing on the distinguishing features of the two methodologies, namely:

- the strength of incentives provided to reduce cost and, related to this, the level of certainty over the recovery of costs incurred;
- the level of average prices over the period and the permitted time profiles for tariffs; and
- level of administrative costs expected from applying each of the methodologies.

The chapter also comments on the relevance of accounting conventions developed for other purposes for the approach to asset revaluation, and provides some comments on a related issue of the appropriate role of 'regulatory stranding' and 'prudence tests' when updating the regulatory asset base for a regulated transmission entity.

4.2 Strength of the incentive to minimise cost / certainty about cost recovery

The discussion of the relative merits of the ODRC revaluation methodology is divided into two periods, the short term and the longer term.

Most appropriate methodology in the short term

We do not consider that the setting of prices completely independent of cost is feasible for regulated electricity transmission businesses in the short term.

The discussion in section 3.1 has identified a number of complex methodological issues that would need to be addressed in order for the ODRC revaluation approach to be applied. We are also concerned that, to date, there has been very little wider debate and analysis of the actual estimation of ODRC values, with no disclosure and independent analysis of the robustness of the sources of information and statistical techniques that have been used to produce ODRC estimates. To date, the substantial variation in ODRC estimates for the same assets over short periods of time – and the large range of error often quoted by firms commenting on ODRC estimates – does not lend weight to the proposition that current ODRC practice of estimating ODRC values is sufficiently robust to be used to set regulated charges.

Most appropriate methodology over the longer term

We also do not consider that the application of the ODRC revaluation methodology would provide for the most appropriate set of incentives for the regulated transmission providers over the longer term.

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

The lack of public debate to date on the accuracy of engineering models for predicting the efficient cost of electricity transmission makes it difficult to make strong conclusions about the likely bounds of uncertainty for these cost predictions. However, a comparison with the models employed in telecommunications – which are subject to substantial debate – do not provide much room for optimism over the accuracy of models for predicting electricity transmission costs. Indeed, a comparison of the output provided by the two most popular models for estimating 'proxy costs' for telecommunications network elements showed an average difference of 50 per cent.[30] The author's conclusion on the appropriateness of cost-prediction models for setting telecommunications access charges was as follows:[31]

> Thus, I strongly suggest that regulators around the world learn from the US experience and avoid the use of cost proxy models in setting prices on interconnection and unbundled network elements.

Given the risks associated with the inevitable error associated with the prediction of efficient cost, it is difficult to see how the Commission credibly could commit to adhere to such a regulatory regime over the long term. It is noted that in the recent report to the Utilities Regulators Forum on different regulatory approaches, Farrier Swier Consulting appeared to reject the 'economic engineering approach' – of which the ODRC revaluation approach is an example – as one that could potentially be applied as the primary approach in Australia.[32]

That said, it is considered that the Commission should keep under consideration the question of whether the use of a five year regulatory period and efficiency carry would be expected to provide the most appropriate set of incentives for regulated entities. It may well be appropriate for Australian regulators to consider lengthening the time between price reviews in order to increase the strength of incentives on regulated entities to reduce cost.

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[30] Dippon, C 2001, 'Local Loop Unbundling: Flaws of the Cost Proxy Model', *Info*, Vol 3, No 2, April, p.165.

[31] Dippon, C, 'Local Loop Unbundling: Flaws of the Cost Proxy Model', *Info*, Vol 3, No 2, April 2001, p.171.

[32] The use of an ODRC valuation methodology equates to what was referred to as an 'engineering economic analysis' in the recent report to the Utilities Regulators Forum on different regulatory approaches (Farrier Swier Consulting, Comparison of Building Blocks and Index-Based Approaches, Report to the Utility Regulators Forum, June 2002, p.33). Farrier Swier Consulting appeared to reject the 'economic engineering approach' as one that could potentially be applied as the primary approach in Australia, although did not set out clearly the reasons for rejecting the approach (Farrier Swier Consulting, op cit, p.35).

However, it is considered that a lengthening of the time between reviews would require improvements in the way in which the trajectory of prices over the regulatory period is set in order to reduce the scope for regulated entities to use their asymmetric information to ensure that the price path is likely to generate windfall gains. A productive way forward for the Commission would be to use methods that place less emphasis on internally generated forecasts of matters like expenditure and demand over the period and more emphasis on external estimates of trends in partial or total factor productivity growth.

4.3 ODRC and Efficient Prices

Introduction

As discussed above, one of the objectives of regulation is to produce prices that reflect the 'scarcity' of the resources consumed in providing the regulated service. Such a price will ensure that users of the system face a signal that reflects the cost of providing the regulated service. In turn, this should lead to consumers making decisions that reduce the cost of providing the regulated service overall – for example, locating a generator closer to the source of demand, or turning off equipment when the network that would supply into an area is constrained.

What is an Efficient Price at a Point in Time?

The correct price signal for the scarcity of the resources consumed by a particular user is the marginal cost of providing that customer's service. The marginal cost is the change in the forward-looking cost associated with providing the last unit of service.

However, as electricity transmission networks are generally characterised by economies of scale and scope, both short run and long run marginal cost will generally sit below the average cost of providing supply. This is just the well-known problem of natural monopoly, where setting prices consistent with (forward-looking) change in costs caused by any particular customer would fail to permit recovery of the whole of the cost of providing the service.

Given that all of the cost of providing the regulated transmission services needs to be recovered from customers,[33] the shortfall in cost needs to be recovered from customers. Given this constraint, the prescription for efficient pricing becomes one of recovering the remaining costs in a manner that has the least impact on usage and investment decisions compared to the decisions that would have been made had customers faced the efficient prices. In turn, this implies recovering the remaining costs through charging components that have the least impact on demand, which would be expected to involve some form of non-linear pricing (such as multi-part tariffs with different types of fixed components, a usage charge that varies with the level of usage, etc).

[33] An option that is normally discussed in text book analyses is that the residual cost component be subsidised by the government through taxes, which may generate a lower deadweight loss than raising the price of electricity. This option is assumed not to exist in this report.

An implication of the discussion above is that it is the structure of prices – rather than the average level – that is more important for efficiency at a point in time.[34] Moreover, there is no reason to consider that prices determined to reflect the price that a the hypothetical (efficient) new entrant would charge at any point in time have a claim to being the most efficient charge – as a mark-up or extra charge in addition to efficient charge would be required to recover costs. Rather, given that a residual amount needs to be recovered from customers over the life of the relevant asset – while at the same time not distorting their usage of the system – the relevant question becomes what is the *optimal rate of recovery of costs over time*, and whether there is a distinction between the two valuation methodologies on this basis.

The question of the optimal rate of recovery of costs over time is a question of the most efficient rate or profile of depreciation for regulatory purposes, which is addressed next.

Efficient Prices over Time – Regulatory Depreciation

The regulatory depreciation allowance is the return of capital to investors over the life of the asset. Provided that prices are expected to deliver a present value of future cash flow equal to the original cost of an asset, the sum of the regulatory depreciation allowance over time will equate to the original cost of the asset.[35] In parallel, the profile of the regulatory depreciation allowances over time will determine the time profile of charges to customers over the life of the asset – and equally, the time profile of charges will imply a regulatory depreciation profile (provided that the set of prices is expected to deliver a present value of future cash flow equal to the original cost of the asset).[36]

As discussed in section 3.1, re-setting the regulatory asset base at the ODRC value at each price review implies that a unique time profile of charges over time would be established. The time profile would reflect the prices that would be charged by the hypothetical (efficient) new entrant at any point in time – which in turn would imply a unique profile of regulatory depreciation allowances.

In contrast, if the regulatory asset base is rolled-forward, flexibility exists in relation to the time profile of regulated charges (and regulatory depreciation). Subject to the rate of regulatory depreciation being sufficiently fast that the provider would always expect to be able to set prices that recover its revenue requirement given the actual (rather than hypothetical) threat of future competition, any regulatory depreciation profile can provide a stream of income that has a present value that equates with the regulatory asset base.

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34 A constraint is that the average prices (or revenue cap) be sufficiently high that it permits charges that reflect marginal cost. Such an outcome would be consistent with an efficient rate of regulatory depreciation, which is discussed below.

35 If a nominal return is provided, then the sum of regulatory depreciation allowances expressed in 'money of the day' terms will equate to the original cost of the asset. If a real return is provided, then the sum of regulatory depreciation allowances expressed in constant price terms will equate to the original cost of the asset.

36 It is important to note that the profile of regulatory depreciation and the profile of prices will not (at least not necessarily) be the *same* – but just that there is a necessary relationship between the two.

Comparing the two asset valuation methodologies, it is noted that the roll-forward methodology would permit the same regulatory depreciation profile (and hence time profile of regulated charges) as that implied by prices reset at the level consistent with the hypothetical (efficient) new entrant, but would permit other profiles of depreciation (and prices) to be selected. The only constraint on the profile of regulatory depreciation under the rolled-forward methodology would be the minimum rate necessary to ensure that the provider is always able to set charges that will recover the revenue requirement in the future, given potential future actual competition. Thus, the rolled-forward asset valuation methodology would appear to have the advantage of providing greater flexibility over the methodology where the regulatory asset base were re-set to an estimate of the ODRC value.

The greater flexibility offered by the rolled-forward methodology then raises the question of whether the use of the re-ODRC methodology may rule out a more efficient time profile of prices (and regulatory depreciation allowances).

In most applications in financial economics, the appropriate measure of depreciation is the rate of economic depreciation. Economic depreciation can be defined as the change in the market value of an asset between two points in time (adjusted for cash flows into or distributions from the relevant financial asset over that period).

However, where monopoly assets are regulated, there is a degree of circularity in attempting to use economic depreciation, as the rate of economic depreciation will reflect the depreciation methodology that is selected by the regulator. This reflects the fact that the selected regulatory depreciation profile determines the profile of prices over time, and hence affects the time profile of revenue – thus determining the change in the value of the asset. The one caveat to this conclusion is that the asset owner must expect to recover the whole of the value of the regulatory asset base over its economic life. This latter constraint implies that regard must be had to the price at which the service may be subject to actual competition in the future (in turn, depending on matters like the rate of technological improvement), and sets a lower bound to the rate of regulatory depreciation.[37] Within this bound, any regulatory depreciation schedule is consistent with economic depreciation.[38]

[37] The impact of future competition on the permissible regulatory depreciation profiles was analysed in: Crew, M and Kleindorfer, P (1992), Economic Depreciation and the Regulated Firm under Competition and Technological Change', *Journal of Regulatory Economics*, Vol 4, pp.51-61.

[38] This latter general proposition has been demonstrated by, amongst others, Schmalensee, R (1989), 'An Expository Note on Depreciation and Profitability Under Rate-of-Return Regulation', *Journal of Regulatory Economics*, Vol 1, pp.293-298.

The concept of economic efficiency provides further insights for the rate of regulatory depreciation than specifying a lower bound, however. As discussed above, the presence of economies of scale and scope in electricity transmission imply that a component in excess of the efficient price will have to be recovered from customers. As the economic distortion associated with the recovery of the residual costs may be affected by the amount that is to be recovered in each particular period, the efficient rate of regulatory depreciation can be defined as the is the rate that minimises the impact on usage of the regulated asset from recovering the residual cost of providing the service discussed above over time, provided always that this depreciation profile would ensure that the asset owner would expect to recover the whole of the value of the regulatory asset base over the economic life of the asset.[39]

The derivation of such a rate of depreciation is a complex task, however. In principle, it requires a view on the profile of marginal cost over time, as well as any change in the likely demand responsiveness of customers between periods. It also requires a view on all other factors that would affect price levels over time, such as trends in operating and capital expenditure, and demand. However, some of the implications that follow from simple models include the following:

- increasing operating costs over time as assets age would imply that the optimal cost recovery would be more *front-ended*, all else constant;
- falling replacement costs over time would imply that optimal cost recovery would be *back-ended*, all else constant falling ; and
- where demand is increasing over time, the optimal rate of recovery would be *back ended* (and vice versa if demand is expected to decrease), all else constant.

While the time profile implied by pegging prices to those that would be charged by the hypothetical (efficient) new entrant would also be affected by these factors, the rate of economic depreciation implied by the hypothetical (efficient) new entrant asset valuation may be expected to depart from the efficient rate, for the following reasons:

- Under the hypothetical new entrant valuation, changes in the replacement cost of assets would be assumed to flow directly into the assumed hypothetical new entrant price, and hence imply a faster rate of regulatory depreciation. In contrast, as noted above, the efficient rate of regulatory depreciation would be expected to imply a back-ending of depreciation (ie a slower recovery) where the replacement cost of assets is expected to fall (subject to the ability for the regulated entity to set prices that recover its revenue requirement).
- Under the hypothetical new entrant valuation, the full (average) cost of providing service in each period would be reflected in prices for that period. Thus, where demand is expected to rise – and there are strong economies of scale and scope in the provision of the service – prices would be high in the early years and fall over time. In contrast, the optimal rate of recovery of costs would imply a *deferral* in the recovery of the residual cost if there is expected to be a greater number of customers – over whom the residual costs can be – spread in the future.

[39] Baumol, W (1971), 'Optimal Depreciation Policy: Pricing the Products of Durable Assets', *The Bell Journal Economics and Management Science*, Vol 2, pp.638-656.

In the absence of actual contestability of a service, there is no compelling reason to fix the time profile of cost recovery to the outcome that would be expected to be observed in such a market if it existed. Moreover, the discussion above suggests that the time profile of charges implied by the hypothetical (efficient) new entrant standard may depart materially from the profile that would be economically efficient in some cases – for example, where replacement costs are expected to fall at a fast rate (subject to the ability to recover all cost) or demand is expected to grow over time. Accordingly, the additional flexibility for regulatory depreciation implied by the roll-forward approach may permit a more efficient time profile of regulated charges to be adopted.

The UK Office of Telecommunications Regulation, in explaining its approach to modelling economic depreciation for regulated mobile termination calls, reached a similar conclusion:[40]

> 20 One way to specify the competitor constraint would be the contestable market approach. It could be assumed for the purposes of the analysis (even if this represents a departure from reality) that entrants never experience a type (i) difference compared to incumbents. In a contestable market entrants face no barriers to entry and so would always be able to achieve the same utilisation as the incumbent(s) in any calendar year. So, for illustration, assume that the incumbent invested three years ago and achieved 50% utilisation in its first year of operation and 75% in its second year before reaching 100% in the current year. The contestable market approach would mean that the entrant in the current year would be assumed to achieve 100% in the current year, its first year of operation (and so has greater type (ii) efficiency than the incumbent).
>
> 21 Competition from potential entrants to a contestable market would be sufficient to ensure the removal of super-normal profit (whatever the number of incumbents or the nature of competition among them). The incumbent would be unable to defer depreciation when utilisation is low. If input costs (MEA price and operating expenses) were constant, then the economic depreciation profile under contestability would be a constant annual cost recovery (in £) each year. The unit cost (or price) would be inversely proportional to utilisation.
>
> 22 Although contestability provides a feasible answer to the specification of the competitor constraint, the price/unit cost profile that it implies seems unattractive. When utilisation is very low, the price/unit cost is very high and vice versa. It also involves an assumption about new entrants that seems very unrealistic.

It follows that the roll forward methodology may permit a more efficient spreading of costs over time than one where prices are reset periodically at the level that would be charged by a hypothetical (efficient) new entrant.

4.4 Administrative Costs and Complexity associated with the Different Options

One of the factors upon which the Commission has sought comment is the administrative costs and complexity associated with the different options. However, in the absence of a fully specified and road-tested ODRC methodology, it is difficult to be definitive about the relative administrative costs of the different valuation approaches. Notwithstanding, some observations on the potential administrative costs are set out below.

[40] Oftel, Calls to Mobiles: Economic Depreciation, undated (available at: http://www.oftel.gov.uk/publications/mobile/depr0901.htm)

As discussed already, a significant point of difference between the two methodologies is the upfront 'investment' required to implement each. While the roll-forward methodology is used already – and has widespread experience of use in other jurisdictions[41] – a substantial refinement to the estimation of ODRC values for electricity transmission networks would be needed before this could be considered as a feasible option in Australia.[42] Moreover, there is little or no precedent for the use of ODRC as the basis for revaluing electricity (or even energy) networks in other jurisdictions from which to learn.

Once estimated, the relative costs and complexity of administering the respective methodologies is likely to depend upon the difficulty of obtaining the information necessary to implement the approach – and the scope and incentive for the provider to contest the application of the methodology.

The range of assumptions required for the estimation of an ODRC value – and the fact that the provider would stand to make windfall gains (or losses) if the value is estimated incorrectly – would suggest that the derivation of an ODRC value is likely to require substantial resources from the regulator as well as the regulated entity. In contrast, updating the regulatory asset base using the roll-forward method requires only information on what has actually been spent over the previous period, which is reasonably straightforward to obtain. Moreover, any cost-prediction model is likely also to require information on actual expenditures undertaken by utilities – and potentially on a more disaggregated basis and for more companies than that required simply to roll-forward regulatory values.

One matter that could require substantial resources under the roll-forward model is testing for the efficiency of investments (and operating expenditure) undertaken during the previous regulatory period. However, as discussed in section 2.2, the use of incentive regulation to encourage regulated entities to undertake only efficient expenditure offers the opportunity for regulators place less emphasis on second-guessing the efficiency of investment decisions.

A further significant point of difference between the two methodologies is the level of analysis required to determine the allowance for regulatory depreciation. As noted in section 3.1, under the ODRC method, the regulated entity would make a windfall gain or loss if the regulatory depreciation factored into regulated charges differed from the change in the ODRC valuation over the regulatory period (adjusted for additions). Accordingly, the entity would have a strong incentive to attempt to inflate the allowance made for regulatory depreciation – and for which the correct value would be very difficult to calculate – implying that this input is likely to require substantial resources from the regulator and regulated entity.[43]

[41] Refer to the discussion in Chapter 5.

[42] As noted in section 3.1, if the Commission elects to continue to revalue assets based upon the hypothetical (efficient) new entrant standard, a methodologically simpler approach would be to use ORC – rather than ODRC – thus replicating the approach in telecommunications.

[43] The 'correct' level of regulatory depreciation requires a forecast of the ODRC value at the end of the period – thus requiring (amongst other things) an assumption about the trend in construction costs, demand, the optimal configuration consistent with the change in demand.

In contrast, under the roll-forward approach, a change to the rate of regulatory depreciation implies a commensurate change to the regulatory value of the business, and not affect the value of the regulated cash flows (at least if the regulator's estimate of the cost of capital is correct). Thus, the appropriate regulatory depreciation rate should be less controversial – indeed, it would be appropriate for the regulator to provide some flexibility over the rate of regulatory depreciation adopted.

Lastly, the issue upon which much effort by regulators and regulated entities has been spent is the estimation of the cost of capital associated with the relevant regulated activities. It is noted that both the ODRC revaluation methodologies and the roll-forward methodology requires an estimate of the cost of capital, and this estimate is equally important to the derivation of regulated charges under each approach. Thus, neither methodology has an advantage over the other with respect to the assumption about the cost of capital associated with the regulated activities.

On balance, it is difficult to see that the use of an ODRC revaluation approach would imply a reduction in the administrative cost or complexity associated with setting revenue caps. As well as the initial investment required to make the ODRC revaluation methodology feasible, its continued use inevitably will leave room for dispute which – given the sums of money likely to be at stake – regulated entities will have an incentive and even duty to their shareholders to seek to exploit. The use of the roll-forward methodology also is not costless, but it is known and widely used, and does not offer the same windfall gains and loss as the ODRC revaluation methodology. Moreover, the greater use of incentive regulation offers the prospect of reducing the cost of implementing the roll-forward model over time.

4.5 Efficient prices and choice of augmentation projects

As noted in section 2.4, a positive effect of revaluing assets at their ODRC value is that this may provide regulated entities with the incentive to have regard to events beyond the current price control period when setting tariffs and deciding on the most appropriate means of meeting increasing demand. In particular, the regulated entity would have an incentive to take account of the value of a flexible response.

The importance of such an incentive is an empirical matter. However, it can be concluded that the benefits from supplementing the incentives provided by the price control would be less important as the length of the regulatory period is extended, and the benefits of such incentive arrangements would need to be traded off against the adverse effects of increased risk for providers from the ODRC revaluation method, discussed above.

However, for electricity transmission, providing regulated transmission entities with an incentive to set efficient prices and to select efficient augmentation projects is likely to be of little practical relevance given that the provider has no incentive over the structure of tariffs, and because the 'regulatory test' required for regulated investments already provides a 'screen' over the efficiency of the response to demand growth.

4.6 Regulatory Asset Valuation vs Financial Accounting

The concept of revaluing assets at an ODRC value has similarities to concepts taken from the financial accounting field. This raises the question as to whether the use of similar concepts for financial accounting purposes provides any further justification for revaluing assets at their ODRC value over time. This matter is addressed below.

Measuring Financial Performance of Government Business Enterprises

The National Electricity Code requires the Commission – when deciding how to set a regulatory value for network assets and to revalue these assets over time – to have regard to the Council of Australian Government's agreement that the Optimised Deprival Valuation methodology should be the preferred basis for valuing transmission assets.[44] As the ACCC has recognised, an ODRC valuation is one of the possible outcomes of the Optimised Deprival Value methodology.[45] This raises the question as to the genesis of the Optimised Deprival Value methodology, and whether it is appropriate as a basis for economic regulation.

As the Productivity Commission has noted, the genesis of deprival value techniques was the desire in the late 1980s and early 1990s to improve the measure of the financial performance of government business enterprises as part of a suite of measures intended to improve what was considered to be poor financial performance. The Productivity Commission has highlighted the differences in the objectives behind the measurement of financial performance on the one hand and economic regulation on the other.[46]

> Underlying the Red Book exercise was governments' desires to improve the generally *inadequate* returns earned by government businesses. In contrast, regulators' concerns are, by and large, to prevent *excessive* returns. That is, rather than using asset values as a monitoring tool, regulators use it to control returns. For the reasons outlined above, it does not necessarily follow that a valuation method appropriate for measuring financial performance is appropriate in all cases for controlling monopoly power.

In particular, the regulatory asset base in regulation has a specific purpose, which is to reflect the value of the regulated assets in the eyes of the regulator at each point in time, and the test for the appropriateness of any method for updating of the regulatory asset base has specific objectives – which is to ensure that the method by which the regulatory value is changed over time provides incentives for efficiency, including to minimise cost but also to continue to investment in the regulated activities where it is efficient to do so. There should be no presumption that accounting conventions developed for other purposes – such as measuring the financial performance of government businesses – are appropriate for this task.

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[44] National Electricity Code, clause 6.2.3(d)(iv).

[45] Australian Competition and Consumer Commission, Draft Statement of Principles for the Regulation of Transmission Revenues, May 1999, p.39.

[46] Productivity Commission, Review of the National Access Regime, Inquiry Report No.17, September 2001, p.361.

Financial Capital Maintenance vs Operating Capital Maintenance

Another debate from the financial accounting field that has been transposed into the regulatory field is the debate about the most appropriate measure of income for financial accounting purposes – that is, whether income should be measured on the basis of the financial capital maintenance concept, or on the basis of the operating (or physical) capital maintenance concept. The differences between the options for the measurement of income are as follows:

- Financial capital maintenance – in which income is defined as the surplus after a sufficient amount has been reserved to maintain the financial value of the business or asset; and
- Operating (physical) capital maintenance – in which income is defined as the surplus after a sufficient amount has been reserved to maintain the physical capability of the asset.

The main distinguishing features of the two are the meaning of depreciation and the basis of asset valuation. Under financial capital maintenance, depreciation is just the return of the original cost of the investment and the book value represents the financial value. In contrast, under operating capital maintenance, depreciation is a provision sufficient to fund replacement of the existing assets when they expire, and the book value reflects the depreciated replacement cost of the current assets. At least on the face of it, the operating capital maintenance concept appears similar to revaluing regulated assets at the ODRC value over time.

For regulation, either of these approaches could be used with appropriate modifications, although the financial capital maintenance approach most closely resembles the accounting convention that regulators have used when setting regulated charges. To set regulated charges based upon the operating capital maintenance approach, the modifications required would include:

- to base depreciation charges on the full current cost valuation of the asset;
- to revalue the regulatory asset base at the full current cost valuation of the asset at price reviews;
- to escalate prices (and the regulatory asset base) by a price index for capital costs rather than the general CPI; and
- to either adjust the regulatory WACC (or to achieve the same effect by adjusting the revenue benchmark) to account for projected holding gains or losses if capital costs are expected to move at a different rate to prices generally.

The main implication of a move to an operating capability maintenance approach would be that investors would be exposed to the risk associated with the unpredicted changes in capital costs relative to prices generally over time, assuming that the opening regulatory value of their assets was the current cost asset valuation.[47]

[47] If the regulatory asset base for the business commenced below the full current cost value, the regulated entity would receive a windfall gain from having prices set on an operating capital maintenance approach: see footnote 77.

More importantly, the debate behind the relative merits of the financial capital maintenance concept and the operating capital maintenance concept in the financial accounting field revolves around which approach is likely to deliver the closest approximation for economic income. For regulated assets, however, the debate over the best proxy for economic income has little relevance – as the regulator effectively determines economic income by setting regulated charges.[48]

As noted above, the relevant objectives for selecting the most appropriate method for updating the regulatory value of transmission assets is not to derive a better measure of economic income, but rather to encourage economic efficiency. Accordingly, again, there should be no presumption that accounting conventions developed for other purposes are appropriate for setting regulated charges.

4.7 Role of Regulatory Stranding and Prudence Tests

In section 3.4, the revaluation of the regulated assets at an estimate of their ODRC value was distinguished from two other tools that regulators may employ, namely 'regulatory stranding' or partly used or unused assets, and the application of a 'prudence test' to new investment. It was noted that neither of these tools are compatible with the ODRC revaluation methodology, but either or both could be employed as additional measures if the 'rolling forward' methodology is used to update the regulatory asset bases of regulated transmission entities.

While it is beyond the current brief, a couple of comments on the appropriate role of these tools are provided below.

The relevant objective when considering whether either or both of the measures should be employed – and how the particular measure should be employed – is the pursuit of economic efficiency and its implications as discussed in Chapter 2.

Regarding the application of a prudence test, it would be expected that the reliance that regulators are required to place upon a formal prudence test would depend upon the strength of the incentives that are provided to regulated entities to minimise cost. In particular, the presence of strong incentives to minimise cost should permit regulators to draw an inference that expenditure was efficient. However, as the design of incentive arrangements inevitable involves a degree of imprecision, the ability to undertake a formal prudence test should be maintained, at least as a fallback.[49]

[48] As discussed in section 4.3, subject to the constraint that a regulated entity always be able to set prices that recover its revenue requirement, any regulatory depreciation schedule is also economic depreciation.

[49] As discussed in section 3.4, the Commission's 'regulatory test' includes a formal prudence assessment for new augmentations.

With respect to 'regulatory stranding', the position is less clear cut. While the threat of future 'stranding' may provide further incentive to minimise cost – and also force a regulated entity to take account of events that extend beyond the next regulatory period when setting regulated charges and selecting the appropriate means of meeting demand growth (given uncertainty about future demand) – a credible threat to 'strand' assets creates further uncertainty,[50] and which may impact upon investment. It is for this reason that some Australian regulators have elected not to preserve the ability to 'strand' assets at future price reviews.[51] However, whether some form of 'regulatory stranding' is considered appropriate for a particular case is a matter that needs to be considered in light of the objectives discussed above – in particular, the relative size of the potential positive and negative impacts on efficiency – and in light of other regulatory tools that may be for achieving the same ends (such as extending the price cap period).

50 As 'regulatory stranding' would have a one-sided impact on future cash flow, the threat of substantial future 'regulatory stranding' would need to be compensated for in regulated charges.

51 See, for example, Essential Services Commission (Victoria), Review of Gas Access Arrangement – Final Decision, October 2002, pp.152-155.

Chapter 5

Practice in Other Industries and Jurisdictions

The purpose of this section is to summarise the approaches that other energy regulators have used to update the regulatory asset bases for regulated entities in Australia and in selected other jurisdictions.

5.1 Australian Experience

Gas Transmission and Distribution

The methodology for updating the regulatory asset base for gas transmission and distribution businesses is determined by the National Gas Code, and requires the 'rolling-forward' method to be used to update the regulatory asset base.[52]

The Gas Code requires a 'prudence test' of capital expenditure[53] – although it leaves regulators with discretion as to how to satisfy themselves that the test is satisfied.[54] The Gas Code also permits 'regulatory stranding',[55] but also requires that the option of stranding assets be announced in advance, and reflected in either the rate of regulatory depreciation or return provided on the regulatory asset base.[56]

Electricity Distribution

The process for updating the regulated asset base in future regulatory periods for electricity distribution is governed by specific legislative requirements in a number of jurisdictions. The relevant legislative requirements or recent views of the jurisdictional regulators are summarised below.

- In New South Wales – IPART has proposed using the roll-forward method to update the regulatory asset bases for the NSW electricity distributors in its current review of their price controls. It has also noted that it will test the prudence of capital expenditure prior to rolling it into the regulatory asset bases.[57]

52 National Gas Code for Third Party Access to Natural Gas Pipeline Systems, section 8.9.

53 National Gas Code for Third Party Access to Natural Gas Pipeline Systems, section 8.16.

54 National Gas Code for Third Party Access to Natural Gas Pipeline Systems, section 8.49. For example, a regulator could infer from the operation of incentive arrangements that the expenditure was prudent.

55 National Gas Code for Third Party Access to Natural Gas Pipeline Systems, sections 8.27-8.29.

56 National Gas Code for Third Party Access to Natural Gas Pipeline Systems, section 8.27.

57 Independent Pricing and Regulatory Tribunal, Regulatory Arrangements for the NSW Network Service Providers from 1 July 2004 – Issues Paper, November 2002.

- Victoria – the existing Victorian Tariff Order provisions require the use of the roll-forward methodology when updating the assets in place at the time of privatisation,[58] which the Essential Services Commission has extended to all assets.[59] The then Office of the Regulator-General expressed strong support for the use of the roll-forward methodology in its earlier consultation papers.[60]

- Queensland – used the roll-forward method to update the regulatory asset bases for the two electricity distributors in its most recent price review.[61]

- In Tasmania, the Office of Tasmanian Energy Regulator has stated that it intends to use the 'roll-forward' method to update the regulatory asset base for the Tasmanian electricity distributor for the next regulatory period, but has indicated that will undertake a further examination of whether it is appropriate to use an updated ODRC valuation to reduce the possibility of an ever increasing divergence between a rolled forward asset valuation and an updated ODRC valuation.[62]

- South Australia – the South Australian Electricity Pricing Order effectively requires the use of the roll-forward methodology to update the regulatory asset base for the South Australian electricity distributor.[63]

5.2 Overseas Regulators

US Practice

Asset valuation methodology

In the US, the basis for the valuation and revaluation of regulated assets remained in a state of flux (and confusion) until the seminal decision of the US Supreme Court in the *Hope* case.[64] Over the previous 50 years before that decision, there had been substantial debate over the appropriate standard for the valuation of regulated assets – which included whether 'fair value' was an appropriate benchmark – with the two most widely used standards being depreciated original cost and revaluations based upon current replacement cost.[65] While the *Hope* decision did not mandate a specific methodology for the valuation of regulated assets, it did reject the use of 'fair value' as an appropriate standard, and also signalled a substantial withdrawal of the Court's role in settling disputes between regulated entities and regulators, instead emphasising pragmatism. The implication of this change of approach has been summarised as follows:[66]

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58 Victoria Electricity Supply Industry Tariff Order (Victoria), clause 5.10.

59 Office of the Regulator-General (Victoria), Electricity Distribution Price Determination 2001-05 – Statement of Purpose and Reasons, September 2000, p.111.

60 Office of the Regulator-General (Victoria), Electricity Distribution Price Review Consultation Paper No.1 – Cost of Capital Financing, May 1999, pp.6-8.

61 Queensland Competition Authority, Final Determination – Regulation of Electricity Distribution, p.63.

62 Office of the Tasmanian Energy Regulator, Research Paper – Electricity Distribution Pricing, December 2002, p.19.

63 Electricity Pricing Order (South Australia), October 1999, clause 7.2(e).

64 Federal Power Commission v Hope Natural Gas 320 U.S. 591 (1945). For an excellent discussion of the various court decisions that spanned this period, and of the contemporary academic discussion, see: Grout, P and A. Jenkins 2001, Regulatory Opportunism and Asset Valuation: Evidence from the US Supreme Court and UK Regulation, CMPO Working Paper Series No. 01/38.

65 It would be difficult to characterise the current replacement cost valuation methodology as equivalent to the ODRC revaluation methodology assessed in this report. For example, Professor Goodman notes that there was disagreement amongst early courts and commissions as to whether a new (cheaper) technology should be reflected in the valuation of an asset – but with the weight of authority favouring the

> As long as the company was able to operate successfully and to attract capital, the courts should not become involved. This doctrine of the end result made it much more difficult for utilities to appeal to the courts, and left decisions in practice to the regulatory commissions.

Following the Hope decision, however, many of the regulatory commissions turned to the use of depreciated original cost as the valuation methodology. Professor Goodman has summarised the current position of US state regulatory authorities as follows.[67]

> This trend of commission decisions favouring original cost has continued. In 1954, the commissions in only nine states out of 43 surveyed by one author followed fair value 'in its traditional meaning', and the remainder relied wholly or predominately on original cost.
>
> At the present time, fair value decisions may be found in only a handful of states governed by statutory or judicial decisions resting on pre-*Hope* criteria. State commissions, where they have been required to use fair value, chafe under this obligation; and some have even after ordered in court to use fair value, continue using original cost. Once given the opportunity to reflect fair value, they have generally done so.

Goodman referred to more recent evidence on asset valuation in the US, which noted that only six of the state regulatory commissions currently place weight on factors other than original cost. Regarding the federal authorities, Goodman noted that:[68]

> The F.E.R.C (and its predecessor, the F.P.C) has extensively employed original cost in its ratemaking proceedings, which include the regulation of the rates for transportation or sale of gas or electricity by gas producers, gas transporters, gas pipelines and by fossil fuel, nuclear, and water-powered electric utilities.

Accordingly, at least since the *Hope* decision, original cost – adjusted for capital expenditure and depreciation – has been the almost universal methodology for regulatory asset valuation in the energy industries in the US.[69]

Other approaches relevant to asset revaluation

Where the US authorities have adopted depreciated original cost as the standard for asset valuation (and revaluation), it has been common practice for two other checks to be applied prior to assets either being included or retained in the regulatory asset base. These are the 'prudence test', and the used and 'useful test'.

The idea of a 'prudence test' had as its background a general distrust of the books of regulated entities early in the 20th century. Thus, when the concept of 'fair value' for the valuation of assets was replaced with original cost, it was generally done so subject to the caveat to that only the prudently invested capital need be considered, not every cost incurred by the company.[70] Goodman has summarised the current standard applied for the 'prudence test' as follows:[71]

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revaluation of the existing technology: Goodman, L 1998, *The Process of Ratemaking*, Public Utilities Reports, Vol 2, p.774.

66 Grout, P and A. Jenkins 2001, Regulatory Opportunism and Asset Valuation: Evidence from the US Supreme Court and UK Regulation, CMPO Working Paper Series No. 01/38, pp.15-16.

67 Goodman, L 1998, *The Process of Ratemaking*, Public Utilities Reports, Vol 2, p.777.

68 Goodman, L 1998, *The Process of Ratemaking*, Public Utilities Reports, Vol 2, p.782.

69 The standard approach in the US has been to roll-forward the regulatory value of assets set in historical cost terms, and – consistent with this – has used a cost of capital defined in nominal terms. This contrasts with the approach that has become standard in Australia of using a cost of capital defined in real terms, and escalating the regulatory asset base for inflation. The difference in these approaches is in the allocation of inflation risk – see Office of the Regulator-General 1999, Cost of Capital Financing – Electricity Distribution Price Review Consultation Paper No.4, pp.8-9.

70 Goodman, L 1998, *The Process of Ratemaking*, Public Utilities Reports, Vol 2, p.856.

71 Goodman, L 1998, *The Process of Ratemaking*, Public Utilities Reports, Vol 2, p.857. There is substantial precedent on the application of this test (see pp.855-883).

> A regulatory commission, therefore, will adopt the 'reasonable man' test found in many areas of the law, including negligence law, as the general standard by which the prudence of utility management must be judged. Under the 'reasonable man' test the fundamental question for decision is whether management acted reasonably in the public interest, not merely in the interest of the company or group of companies. The overriding issue is not the reasonableness of the cost in the abstract but 'a reasonable and prudent business expense, which the consuming public may reasonably be required to bear'.

The 'used and useful' test, in contrast, is a rule that determines whether a particular asset should be included in the regulated charges. Again, Goodman has summarised the relevant principle as follows:[72]

> Under the phrase 'used and useful', the agency does not reach the question whether the capital was prudently invested, because even if it has been prudently invested but will not produce investments used and useful in the public service, the agency may exclude such properties from the rate base. The used and useful principle is also unrelated to 'honest, economic and efficient' management standards. The agency may and in fact, absent contrary proof, will assume that the expenditures were made in an honest, economic and efficient manner. The sole test is whether the capital in issue is representative of properties used and useful in providing the service under regulation.

Again, there is substantial precedent as to the application of this principle. The 'used and useful' principle may permit the cost associated with excess capacity to be removed,[73] and also may reduce the value of assets where the level of usage of the asset has turned out to be lower than expected,[74] but may also permit a sharing of the cost associated with assets removed from the regulatory asset base.[75]

UK Experience

Asset valuation methodology

Despite some unorthodoxy in the method (for water) and some early confusion (for gas), the regulatory asset bases for the UK energy and water utilities have been updated using an approach that is equivalent to the roll-forward methodology discussed in this report. That is, a regulatory asset base for the assets in existence at the time of privatisation was established, which has then been updated at the time of subsequent price reviews to include capital expenditure undertaken over the previous period and to deduct depreciation.

The unorthodoxy for *water* derives from the method that OFWAT has used to determine the depreciation allowances for the regulated assets in place prior to privatisation and the consequent adjustment that is made to the roll-forward formula.

- In past reviews, OFWAT has determined depreciation allowances for pre-privatisation assets as the full current cost depreciation charge for overground assets and an 'infrastructure renewals' charge for underground assets. As the regulatory value of the water businesses' pre-privatisation assets is only a small fraction of the current cost values, the resulting depreciation allowances would return a value over the life of the relevant assets that would be many multiples of the regulatory value.

[72] Goodman, L 1998, *The Process of Ratemaking*, Public Utilities Reports, Vol 2, p.799.
[73] Goodman, L 1998, *The Process of Ratemaking*, Public Utilities Reports, Vol 2, p.800.
[74] Goodman, L 1998, *The Process of Ratemaking*, Public Utilities Reports, Vol 2, p.804.
[75] Goodman, L 1998, *The Process of Ratemaking*, Public Utilities Reports, Vol 2, pp.819-825.

- However, OFWAT also uses the (high) regulatory depreciation allowance calculated as described above when rolling-forward the regulatory values for the businesses. Thus, no windfall gain would be received (that is, an expected present value of future net cash flow equal to the regulatory value). The only effect of the use of the higher rate of regulatory depreciation is that capital would be returned at a faster rate than if OFWAT had calculated depreciation based upon the regulatory (rather than current cost) values of the pre-privatisation assets.

OFWAT is currently consulting on whether to maintain its existing approach for calculating depreciation allowances, with one alternative being to calculate depreciation based upon the regulatory values of the assets in place.[76]

The early confusion for *gas* arose from the then Monopoly and Mergers Commission's approach in its 1993 decision on Transco (the gas transmission and distribution company). The error made by the MMC was to:

- calculate depreciation based upon the full current cost value of the regulated assets (which exceeded the regulatory value by a substantial margin); but
- to roll-forward the regulatory asset base for Transco using depreciation calculated on the regulatory value of the assets.

The inconsistency between the depreciation included in prices and that used to roll-forward the regulatory asset base would be expected to provide a windfall gain to Transco (that is, an expected present value of future net cash flow in excess of the regulatory value). The Monopolies and Mergers Commission has since accepted the regulator's view (then the Office of Gas Regulation) that its earlier approach was in error, and has accepted that it would be preferable to structure depreciation allowances to return the regulatory value of the assets. It has also affirmed that the most appropriate measure of inflation for escalating regulatory values is the Retail Price Index (the UK equivalent of the Consumer Price Index) rather than an index reflecting construction costs.[77]

New Zealand

The New Zealand Commerce Commission released a discussion paper in 2002, which canvassed various options for rolling forward the asset base, but as yet they have not outlined a preferred approach.[78]

[76] OFWAT 2002, The Approach to Depreciation for the Periodic Review 2004 – A Consultation Paper, March.

[77] Monopolies and Mergers Commission, BG Plc: A Report under the Gas Act 1986 on the Restrictions of Prices for Gas Transportation and Storage Services, 1997, pp.35-44. The approach the MMC adopted in 1993 reflected an operating capital maintenance approach, as discussed in section 4.6, and the MMC's decision in 1997 reflected a rejection of the operating capability maintenance in favour of a financial capital maintenance approach. A key reason for the MMC's rejection of the operating capability standard as a basis for setting regulated charges was that this approach would be expected to provide a financial windfall to the investors in the privatised assets given that the regulatory values commenced at far less than the full current cost values (p.42).

[78] New Zealand Commerce Commission 2002, *Review of Asset Valuation Methodologies: Electricity Lines Businesses' System Fixed Assets: Discussion Paper*, October.

5.3 Implications for Electricity Transmission Regulation in Australia

The dominant practice both within and outside of Australia for updating the regulatory asset bases of regulated energy utilities is to update values with reference to actual costs incurred rather than to re-set regulatory values at a level that is consistent with the estimated cost structure of a hypothetical new entrant. Accordingly, the weight of practice in Australia and other jurisdictions supports the 'rolling forward' methodology rather than re-setting regulatory values at an estimate of the ODRC value.

Draft Decision

Statement of principles for the regulation of transmission revenue

Market impact transparency measures

Date: 28 July 2004

File no: C2004/681

Commissioners:
Samuel
Sylvan
Martin
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McNeill
Smith
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Glossary

AC	Alternating current
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Markets Corporation
ANTS	Annual National Transmission Statement
COAG	Council of Australian Governments
code	National Electricity Code
DC	Direct current
ERAA	Energy Retailers Association of Australia
MCC	Marginal constraint cost
MCE	Ministerial Council on Energy
MLF	Marginal loss factor
NECA	National Electricity Code Administrator
NEM	National electricity market
NEMDE	National electricity market dispatch engine
NEMMCO	National Electricity Market Management Company
NGF	National Generators Forum
QNI	Queensland to New South Wales interconnector
SCO	Standing Committee of Officials
TCC	Total constraint cost
TNSP	Transmission network service provider
VoLL	Value of lost load

Summary

This is a draft decision on the publication of information (called transparency measures) on the market impact of transmission in the National Electricity Market (NEM) and on the nature of transmission constraints in the NEM.

The transparency measures recommended in this report follow on from the service standard guidelines[1] and the policy direction[2] from the Ministerial Council on Energy (MCE). The Australian Competition and Consumer Commission (ACCC) considers this draft decision to be the first step in the implementation of the MCE's policy.

The service standards working group (working group) has been indispensable in the development of the transparency measures recommended in this report. The working group was first convened in December 2003. Its membership represents generators, retailers, TNSPs, consumers, the National Electricity Market Management Company (NEMMCO) and the National Electricity Code Administrator (NECA) and has met five times over the period to July 2004.

In addition to consulting the working group, the ACCC has consulted the state regulators about this draft decision. Each of the state regulators sits on the ACCC's Energy Committee, which meets to discuss regulatory developments and issues. The Energy Committee supported the increased transparency proposed in this draft decision.

This review is taking place at the same time as arrangements for the Australian Energy Regulator (AER) are being implemented. The AER will assume responsibility for this area of regulation, so depending on the timing of its establishment the AER may make the final decision on this matter. The ACCC anticipates that when the AER is established it will continue this process to completion, including the consideration of economic incentives.

The ACCC expects it (or the AER) will release a final decision in October 2004.

Objectives

The ACCC is currently reviewing its regulatory principles[3], which explain how it regulates transmission network service providers (TNSPs) under the National Electricity Code (code). A draft decision on the regulatory principles review is expected to be released in August 2004 and a final decision in early 2005.

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1 ACCC, Statement of Principles for the Regulation of Transmission Revenues: Service Standards Guidelines, 12 November 2003.

2 Ministerial Council on Energy, Report to the Council of Australian Governments: Reform of Energy Markets, 11 December 2003.

3 ACCC, Draft Statement of Principles for the Regulation of Transmission Revenue, 27 May 1999

To meet the MCE's objective, to develop market based incentives by mid 2004, the ACCC adopted a review process for this draft decision that was separate to the process for the regulatory principles review. However this draft decision about transparency measures, when finalised, will form part of the ACCC's regulatory principles.

This draft decision is a first step and aims to transparently quantify the market impact transmission networks can have. These transparency market impact measures are intended to:

- define and quantify the market impact of transmission
- focus on the factors that affect the extent and severity of transmission constraints
- develop and publish information on the nature and impact of transmission constraints
- promote improved TNSP behaviour
- inform debate about the design of possible economic incentives.

The following step is to design and set, if possible, economic incentives based on the market impact of transmission. The process to consider this next step of work is discussed in section 7.

Possible transparency measures

Working group members proposed four different approaches to measure the market impact of transmission and are summarised as follows.

- **Marginal constraint cost (MCC) of outages measure.** This proposal is to publish the MCC of transmission outages. This measure is the sum of the marginal value[4] as estimated by NEMDE for transmission constraints associated with transmission outages. The NEMDE marginal value represents the amount by which the total energy cost[5] would be reduced if the particular constraint was relaxed by a small amount.

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[4] NEMDE maximises an objective function subject to a set of constraint equations. Mathematically, the conventional way to solve such problems is to convert them into an unconstrained optimisation problem by multiplying each constraint equation by a lagrangean multiplier. If the constraints are specified in a standard way the lagrangean multiplier can be interpreted as the effect on the objective function resulting from a small relaxation in the constraint.

The NEMDE marginal value is the lagrangean multiplier (lambda) for each constraint equation in the maximisation problem. It usually can be interpreted as the reduction in the total cost of energy that arises from relaxing a given constraint by a small amount.

[5] The total energy cost in the case of the NEMDE is the objective function, which includes, the cost of dispatching generation to meet demand and the co-optimisation of the ancillary services markets, amongst other things.

- **Two dimensional incentive**. This is a proposal to develop an incentive to maximise the capacity of NEM interconnectors. It is based on the combination of the accumulated price separation across interconnectors (on the x-axis) and the number of hours of binding constraints in excess of an allowed amount (on the y-axis).
- **Transmission maintenance scheduling incentive.** This proposal was based on the ability of the TNSP to influence the supply and demand balance and the resultant spot price. The proposal aimed to use base load generation plant margin as a proxy for the concentration of generator market power. The TNSP would then be given incentives to prevent increases in market power through its practices in scheduling outages.
- **Total constraint cost (TCC) measure.** This is a proposal to publish the market impact of all transmission constraints based on the cost of being forced to deviate from the least cost dispatch that would otherwise have occurred if the network was unconstrained.

In addition working group members contributed a number of proposals that focussed on improving the transparency of the reporting of transmission constraints and are summarised as follows.

- **Tracking of transmission constraints.** A proposal to improve NEMMCO's tracking of transmission constraints.
- **Publication of line ratings.** This proposal would require TNSPs to publish details of how they rate their transmission assets.
- **Publication of the nature of transmission constraints**. This proposal gives a suggestion regarding analysing the nature of transmission constraints on the TNSP's network.

To evaluate these proposals, the ACCC developed evaluation criteria reflecting consideration of the following.

- The regulatory framework: these are the rules that the ACCC is required to follow in the regulation of TNSPs.
- Economic principles: the ACCC is concerned about developing regulation that is economically sound. It is therefore important to articulate the economic principles relevant to the service standards debate.
- Technical principles: electricity systems are technically complex and the performance of the transmission system is a function of many variables. It is helpful to define these interactions to inform decisions on the appropriate technical features to be considered in assessing different measures.
- Stakeholder views: stakeholders have put a diversity of views to the ACCC on how transmission service incentives should be established and what they should contain.

- Design principles: there are a number of generally accepted principles in the design of regulatory incentives. Much of these would also apply in the selection of transparency measures.

Evaluation criteria

The evaluation criteria were developed with consideration of the above factors. The chosen evaluation criteria, in no particular order, are that transparency measures should, ideally:

- relate the economic benefit of the TNSP's action to the cost
- depend on, as far as possible, the TNSP's action
- be constructed on objective information and analysis that can be audited
- be understandable and unambiguous
- be consistent across TNSPs
- not be based on unsupported assumptions about the importance of any particular factor affecting transmission constraints
- be consistent with the ACCC's National Electricity Code (code) responsibilities.

The four approaches to the measurement of the market impact of transmission were evaluated against these criteria. From this evaluation it is clear that none of the proposals satisfy all the criteria, but it identifies the problems that should be avoided and what work is still required.

At this stage the ACCC's preferred approach is to develop an inclusive set of transparency measures even though some measures may be less useful than others. The ACCC's intention is that these transparency measures should develop dynamically as new analytical techniques and better information becomes available. This may provide the basis to narrow the focus of these measures in due course.

The chosen transparency measures arising from this evaluation can be grouped into two categories. The first category focuses on the market impact of transmission. The second category focuses on promoting better understanding of the nature of transmission constraints.

Quarterly reporting

The ACCC proposes to publish information about the market impact of transmission and about the nature of constraints in the National Electricity Market (NEM).

The information about the market impact of transmission will include the TCC and the MCC measures. This will include a brief narrative about the surrounding circumstances for each high cost constraint. The information about the nature of constraints will mainly include information, provided by TNSPs, that gives an overview of the constraints that occurred on their respective networks for each quarter.

Details of what the ACCC intends to publish are described in section 5 and in appendix D. Appendix D contains a sample report based on the ACCC's constraint cost model, which only estimates the cost of inter-regional constraints.

The market impact information is likely to contain information that may be more contentious to TNSPs and market participants. Therefore the ACCC envisages implementing a process to allow interested parties to comment on the information and for this commentary to be made publicly available. The main steps in this process are as follows.

- The ACCC will compile the market impact measures on the basis of the ACCC constraint cost model available to the ACCC (see appendix C). However if NEMMCO's[6] model is ready for use the ACCC would prefer to use the output of NEMMCO's full model rather than its own simplified model. The details of the quarterly report may be influenced by the output of NEMMCO's model.
- The ACCC will include a brief commentary about the circumstances surrounding significant transmission constraints in a draft quarterly report.
- All interested parties will be able to provide submissions on the draft quarterly report. The ACCC does not intend to respond to every submission but it would include, in the quarterly report, additional information provided in submissions, where it is appropriate.
- The ACCC would publish the final quarterly report and interested party submissions on its internet site.
- The ACCC will review the process as required.

Other avenues to meet stakeholder needs

Finally, a number of stakeholders stressed the importance of improved certainty of network capacity. It is clear that for many stakeholders the uncertainty of the actual capability of networks (particularly at times of system stress) is of considerable importance. This uncertainty is impacted by many factors, including TNSP management of transmission outages. It is noted, however, that there were no submissions on the service standards guidelines or proposals put to the working group that formally proposed that maximising certainty of transmission service should be an explicit objective or criteria.

The ACCC considers that there may be a conflict between maximising the economic value of transmission and maximising the predictability of transmission availability.

[6] The ACCC is liaising with NEMMCO to determine whether it can model the TCC measure more accurately than the ACCC's current model. NEMMCO has indicated that it can assist the ACCC, including providing capability to accurately model the TCC of intra-regional constraints, generator ramp rate constraints, etc. The details of this model are still being developed.

However there are a number of market design and policy initiatives, either underway or to be commenced once the Australian Energy Market Commission (AEMC) has been established, that impact on the certainty and predictability of transmission capacity. Aspects of these initiatives have the potential to affect the relationship between transmission and the wholesale market and to generate information that improves transparency. They may, therefore, be relevant to concerns over uncertainty arising from the operation of the transmission system and operation of the power system.

These initiatives are summarised as follows.

- The MCE has requested that the AEMC, when established, consider the requirement for, and scope of, enhanced inter-regional trading arrangements in conjunction with the development of the future process for managing regional boundary changes.
- The Standing Committee of Officials (SCO) on behalf of the MCE is overseeing an independent review of the existing NEM regional boundary structure.
- The MCE has requested the AEMC/NECA consider the requirement and scope for enhanced inter-regional trading arrangements. The request was that this be done in conjunction with the development of the future process for managing regional boundary changes. In doing so, the AEMC has been asked to draw upon existing work of NEMMCO.
- The existing approach to network constraint management is not delivering optimal power system security outcomes. To address this problem NEMMCO has developed a method to re-formulate particularly ineffective constraints as an interim measure only. NEMMCO is to assist the SCO and the AEMC to develop a permanent solution by offering its technical support to ensure that all important factors are considered in the final policy outcome.

These initiatives are either matters of policy concerning the design of the NEM, or matters of detailed management of power system security and are the primary responsibility of the respective bodies involved.

With regard to a forward-looking assessment of transmission capability, we note that NEMMCO has been tasked by the MCE to publish an Annual National Transmission Statement (ANTS). The purpose of the ANTS is to detail the major national transmission flow paths, forecast inter-connector constraints, and identify options to relieve constraints.

Next steps

The ACCC aims to release a final report in October 2004 and it intends to use the following process to progress this work.

4 August 2004	Call for submissions
1 September 2004	Submissions close
October 2004	Decision and first quarterly report

Much of this report refers to issues about how the transparency measures could be used as the basis for economic incentives. The assessment of this proposition needs to be undertaken with the assistance of market data and further debate on the associated issues. This additional work, given its possible impact on the market, must be carefully considered by the ACCC before an incentive scheme could be included in the service standards guidelines or in a revenue cap decision.

The ACCC acknowledges the value of market based economic incentives on TNSPs and intends to implement such incentives if it is feasible. However, much detailed technical work remains to be done to develop such an incentive. The ACCC is currently developing a process to take this work forward and it will consider the best way for interested parties to participate in this process. It is expected that some form of consultation process will begin in early 2005.

1. Introduction and background

This is a draft decision on the publication of information (called transparency measures) on the market impact of transmission in the NEM and on the nature of transmission constraints in the NEM. The ACCC expects that publishing information about the factors that affect; and the market impact of, transmission constraints will improve TNSP's behaviour in response to such occurrences. Also it is expected that this information will also inform the market what TNSPs already do to minimise the market impact of their actions.

1.1 Background

On 12 November 2003 the ACCC finalised the service standards guidelines, which form part of its regulatory principles[7]. The service standards guidelines outline the ACCC's approach to setting service standards within the revenue cap framework provided by the code. The service standards guidelines outline a scheme that provides economic incentives for TNSPs to improve service quality.

The service standards guidelines can possibly be improved, to better recognise the market impact of transmission. To help assess the possibility of developing market impact incentives, the ACCC established the service standards working group, with members from the industry[8]. The working group was first convened in December 2003 and has met five times over the period to July 2004.

The MCE reported to the Council of Australian Governments (COAG)[9]. In relation to service standard incentives the MCE considers that:

- there would be valuable customer and investor benefits in more closely aligning transmission performance measures with their market impact
- incentive arrangements should analyse the actual cost of constraints
- market based incentives for transmission should be developed by July 2004.

The ACCC considers the transparency measures proposed in this draft decision to be the first step in delivering the MCE's policy direction.

In addition to consulting the working group, the ACCC has consulted the state regulators about this draft decision. Each of the state regulators sits on the ACCC's Energy Committee, which meets to discuss regulatory developments and issues. The Energy Committee supported the increased transparency proposed in this draft decision.

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7 ACCC, Draft Statement of Principles for the Regulation of Transmission Revenue, 27 May 1999

8 The members are representatives from generators, retailers, TNSPs, consumers, NEMMCO, NECA and the ACCC.

9 Ministerial Council on Energy, Report to the Council of Australian Governments: Reform of Energy Markets, 11 December 2003.

This review is taking place at the same time as arrangements for the AER are being implemented. The AER will assume responsibility for this area of regulation, so depending on the timing of its establishment the AER may make the final decision on this matter. The ACCC anticipates that when the AER is established it will continue this process to completion, including the consideration of economic incentives.

The ACCC expects it (or the AER) will release a final decision in October 2004.

1.2 Structure of this report

This report is set out as follows:

- section 2 describes the ACCC's objectives underlying the development and publication of transparency measures
- section 3 establishes criteria for evaluating different transparency measures
- section 4 evaluates various proposals discussed in the working group against the criteria summarised in section 3
- section 5 sets out the ACCC's proposed transparency measures
- section 6 considers additional ways of addressing stakeholder issues
- section 7 sets out the next steps for the development of this work.

Appendixes:

- appendix A is the detailed evaluation of the various working group proposals
- appendix B discusses stakeholder views
- appendix C describes the ACCC constraint cost model
- appendix D is a sample market impact quarterly report.

2. Objectives of the transparency measures

The ACCC is currently reviewing its regulatory principles, which explain how it regulates TNSPs under the code. A draft decision on the regulatory principles review is expected to be released in August 2004 and a final decision in early 2005.

To meet the MCE's objective, to develop market based incentives by mid 2004, the ACCC adopted a review process for this draft decision that was separate to the process for the regulatory principles review. However this draft decision about transparency measures, when finalised, will form part of the ACCC's regulatory principles.

This draft decision is a first step and aims to transparently quantify the market impact transmission networks can have.

Analysing the market impact of transmission is complex. Considerable work is required to determine whether economic incentives on TNSPs to maximise the market value of the transmission networks is possible. The work also needs to assess if a system of economic incentives would result in an overall benefit to the market.

Depending on the outcome of this further work, the transparency measures recommended in this report may be used to derive economic incentives or may be used to simply provide information to NEM participants. The objective of publishing the transparency measures is to:

- define and quantify the market impact of transmission
- focus on the factors that affect the extent and severity of transmission constraints
- develop and publish information on the nature and market impact of transmission constraints
- improve the performance of the NEM by providing improved information to the market
- promote improved TNSP behaviour
- inform debate about the design of possible economic incentives.

There may be different ways to calculate the market impact of transmission and there are a number of different ways to analyse the nature of constraints. The focus at this stage is on developing the best available measures given our current knowledge and data.

The ACCC does not view the transparency measures suggested in this report to be static. Rather the specification and content suggested here will, likely, evolve over time as understanding improves. The process for the continued development of the transparency measures and quarterly reporting is outlined in section 5.1.3 and section 7.

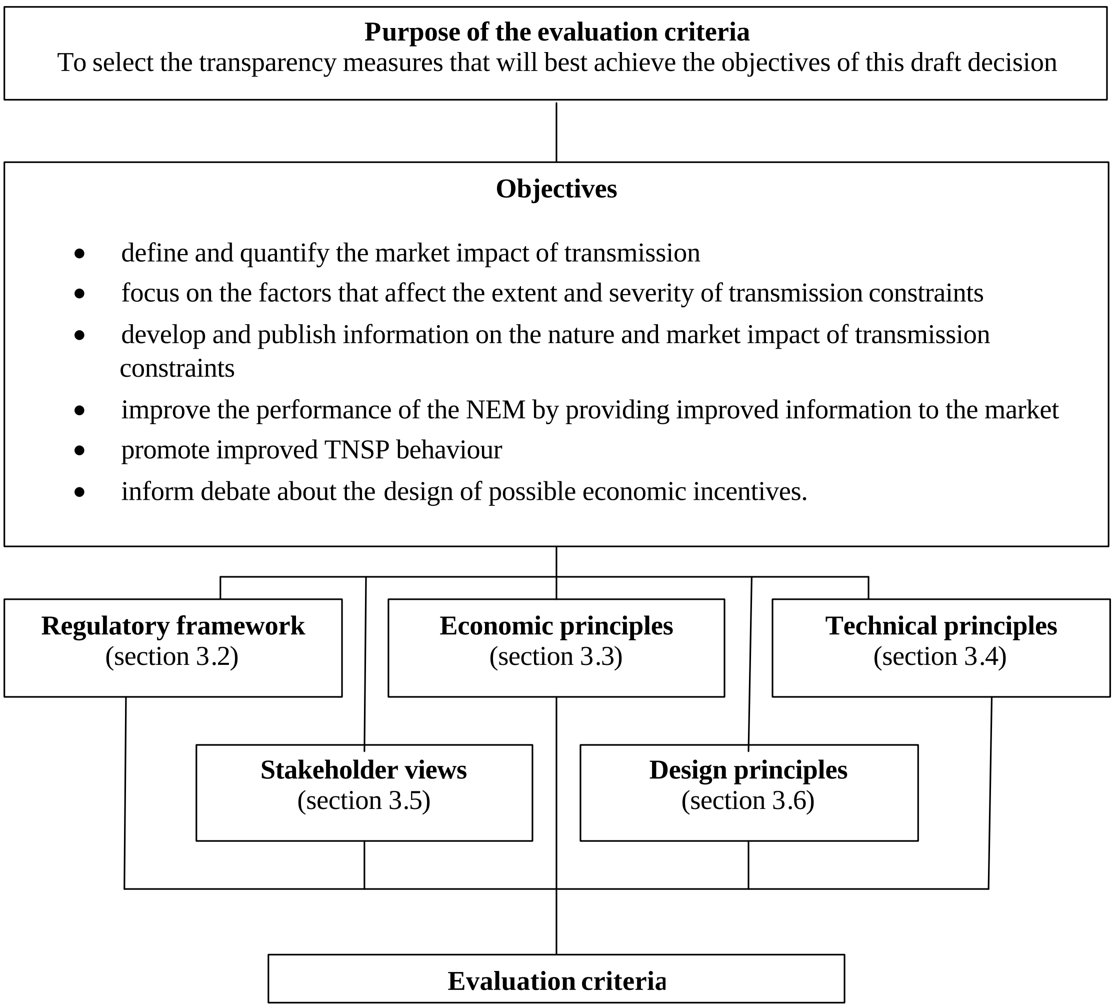
3. Evaluation Criteria

3.1 Introduction

This section sets out the ACCC's criteria to evaluate the proposed transparency measures. The purpose of developing a set of criteria to evaluate the possible transparency measures was to ensure the chosen measures would achieve the ACCC's objectives (see section 2).

The ACCC's approach used to develop the evaluation criteria is summarised in figure 3.1.

Figure 3.1 – Approach to the development of evaluation criteria



The chosen evaluation criteria also reflect consideration of the following.

- The regulatory framework, including provisions of the code that confer the function of transmission regulation on the ACCC and set out the basis for the regulation of TNSPs.
- Economic principles: the code and good regulatory practice require the ACCC to have regard to economic principles.
- Technical principles, the performance of the transmission system is a function of many variables and defining their interactions will inform decisions on the appropriate technical features to be considered in assessing different measures.
- Stakeholder views.
- Design principles: there are a number of generally accepted regulatory principles applied in the design of economic incentives.

The rest of this section considers each of these and discusses the chosen evaluation criteria.

3.2 Regulatory framework

The ACCC is responsible, under the code, for the regulation of TNSPs' revenue. Clause 6.2.4(b) of the code requires that, in performing its regulatory functions, the ACCC should set a revenue cap for each TNSP. The code also sets out the objectives the ACCC should aim to achieve; the principles it should apply; and the form and mechanism of regulation to be used.

Clause 6.2.4(c)(2) requires the ACCC to consider, when setting revenue caps, the service standards in the code and the service standards imposed in its regulatory regime. Hence the ACCC developed the service standards guidelines to outline how it will consider service standards in setting the revenue cap. The working group has been an extension of this work and has helped the ACCC develop the transparency measures in section 5.

The transparency measures are not economic incentives but when designing them it is important that the code objectives and principles be kept in mind. The relevant objectives (clause 6.2.2) and principles (clause 6.2.3) of the code can be summarised as:

- achieving an efficient and cost-effective regulatory environment
- achieving an incentive based regulatory regime
- fostering efficient investment in transmission and also in upstream and downstream markets
- fostering efficient transmission operating and maintenance practices
- fostering efficient use of existing infrastructure
- promoting competition in network services and also in upstream and downstream markets

- achieving regulatory accountability through transparency and disclosure
- balancing the interests of TNSPs and customers
- providing TNSPs with opportunities and incentives to increase efficiency.

The ACCC's view is that these code objectives are primarily focussed on effective regulation of TNSPs, suggesting that any transparency measures should be directed towards the pursuit of that objective.

However, the code also sets some more general obligations on the ACCC that encompass more than just the regulation of TNSPs, such as:

- fostering competition in upstream and downstream markets
- fostering efficient use of existing infrastructure

The ACCC considers that responding to these obligations would encompass the publication of relevant market information, even though it may not specifically be related to the regulation of TNSPs.

3.2.1 Collecting and publishing information

The information collected from the transparency measures is essential to evaluate the potential to develop economic incentives for TNSPs.

The ACCC proposes to gather publicly available market data and calculate the market impact of transmission. TNSPs have responded positively to the ACCC's work to date and have shown a willingness to participate in this process by actively contributing to the discussion. However, the ACCC has powers to require and publish such information if needed. These are set out in clauses 6.2.5 and 6.2.6 of the code.

3.2.2 Implications for evaluation criteria

The discussion above suggests that the transparency measures should be:

- consistent with the code provisions for setting revenue caps
- based on public or volunteered information, where possible
- only based on information provided under a code requirement as a last resort.

3.3 Economic principles

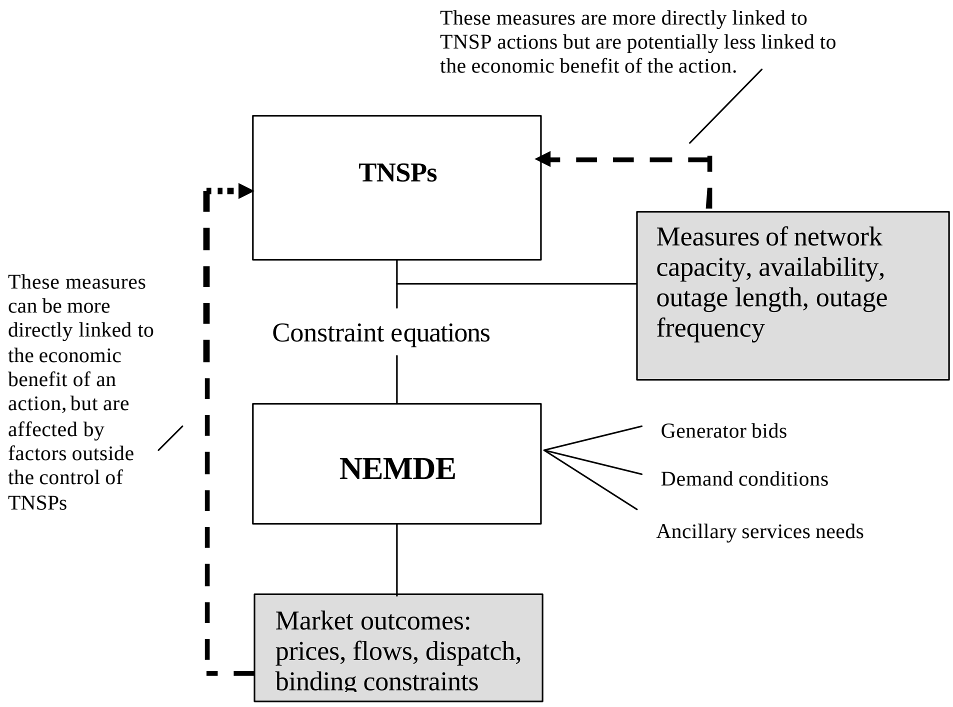
The ACCC is seeking to develop transparency measures which may subsequently help establish an economic incentive scheme. This section focuses on the desirable characteristics of a transparency measure which could act as the basis for a subsequent economic incentive.

An economic incentive mechanism is a system of financial payments which rewards TNSPs for taking actions that increase the quality or quantity of the service they provide. However there is no expectation that TNSPs should take *all* possible actions to increase the quality of the services they provide. Some actions to increase service quality will have costs greater than the benefits. Hence an economic incentive should induce TNSPs only to take action if the market benefit of that action exceeds the cost.

The economic benefit of the TNSP's action depends on some factors that are outside the TNSP's control, such as the generator bidding or the level of demand. But ideally the financial reward should depend, as much as possible, on the impacts that the TNSP is able to manage.

In order to isolate the effect of the TNSP's action from the effect of other factors the transparency measures could be based on indicators that are more closely related to the TNSP's action and only partially on market outcomes. This is illustrated in figure 3.2.

Figure 3.2 – Different measures of TNSP performance and impact



Indicators that more closely relate to the TNSP's action include indicators such as the frequency and duration of outages. These indicators are useful but they suffer from the drawback that they do not normally relate to the economic impacts resulting from the TNSP's action. For example, if an economic incentive scheme treated all outages in the same way, a TNSP may be inefficiently induced to incur outage costs in peak times even though it may be preferable, from a market perspective, to allow longer off-peak outages in exchange for shorter peak outages.

A true measure of the economic impact of the TNSP's action would depend directly on market outcomes, such as the prices and quantities dispatched by the NEM dispatch engine (NEMDE).

The TNSP's actions can have market impacts in the short and long term. These effects are discussed as follows.

3.3.1 Short-term effects

- A transmission constraint can cause generation to be dispatched out of the merit-order, which means that higher cost generation is dispatched in the place of lower cost generation.

  For example, assume there is a load pocket (such as a city) that has local generation with a marginal cost of $1000/MWh. When the capacity of the interconnector into the load pocket is reached the local generation will need to be dispatched to supply any additional local load. This would be the case even when there may be cheaper generation with spare capacity available outside the load pocket.

- A transmission constraint can cause load to be shed or not supplied. In practice, this is a rare occurrence but it remains a theoretical possibility. Considering the above example of the load pocket – if the generation in the load pocket does not have sufficient capacity to supply the additional local load, then that load may not be supplied. This would even be the case if there were consumers willing to pay more than $1000/MWh for electricity.

3.3.2 Medium to long-term effects

- A transmission constraint can affect relative prices across different regions and it can also affect the likelihood that a generator will be dispatched or the price it will be paid for its load. Such a change in price can affect generators' decisions about when to enter or exit the market and also the decision of what generation technology to use. Again considering the load pocket example – the presence of the transmission constraint could induce new, higher-cost generators to locate inside a load pocket even if there is cheaper fuel available elsewhere.
- The change in prices (and/or the possibility of lost load) can also affect the decisions of consumers, such as where to locate or what fuel to consume[10]. In the example consumers in the load pocket may react to higher electricity prices by switching to other fuels, such as natural gas.

In principle, a full analysis of the economic benefit of any change in the transmission network should take into account all of these factors. At this stage, it is not clear whether a full analysis of this kind could be used for the purposes of developing a market based incentive scheme.

3.3.3 Assessing the market impact of transmission

Since load shedding is rare, it is reasonable to ignore the cost of lost load in assessing the market impact of transmission. Therefore the total economic benefit, in the short term, of the TNSP's action can be assessed by estimating the change in the total energy cost of

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10 In addition, to the extent that market participants are risk-averse, an increase in the reliability of the transmission network will lower the risk of load shedding or high prices due to transmission constraints which is an economic benefit in its own right.

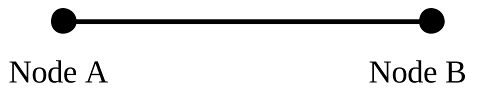
dispatch due to the TNSP's action. A financial reward that is based on this change is directly related to the market impact of the TNSP's action. Therefore the TNSP would be induced to perform such actions as to minimise the market impact, which would maximise the financial reward for the TNSP.

In some simple networks it is possible to relate the change in the total energy cost of dispatch to a change in price (see box 1 for a worked example).

Box 3.1 –Price impact of total energy cost of dispatch

Consider a network with two nodes and one interconnector, as shown in figure 3.3.

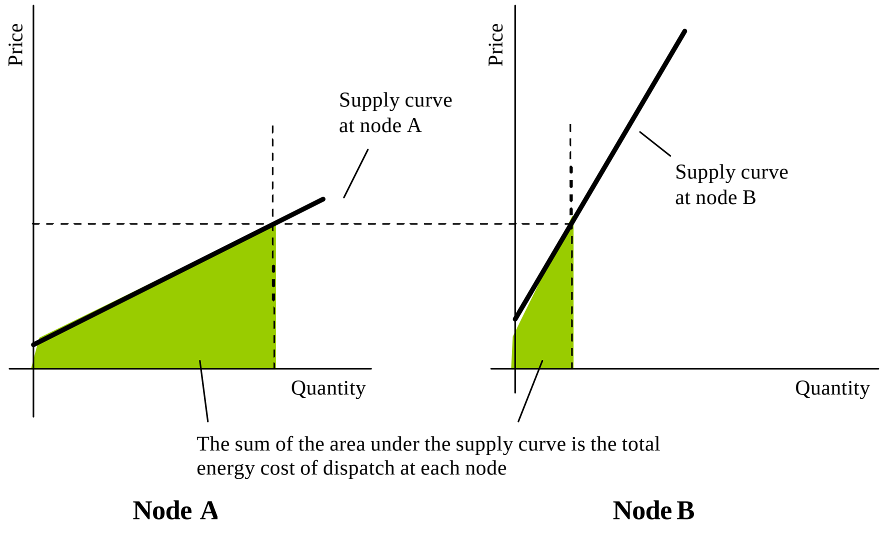
Figure 3.3 – Two node example



Assume that the generation located at node B has higher costs than generation at node A. This means that achieving the least cost dispatch requires generation at node A to be dispatched ahead of generation at node B. The resulting flows on the interconnector will be in the direction from node A to node B. If there is sufficient generation and interconnector capacity (and ignoring losses) the price for electricity will be the same in the two regions.

Figure 3.4 shows the example where the interconnector is unconstrained. It also shows the total energy cost of dispatch as the area under each generator's supply curve up to the amount at which it is dispatched. In the case of no binding network constraints (and no losses) it is the area under the total network-wide supply curve.

Figure 3.4 – Unconstrained case



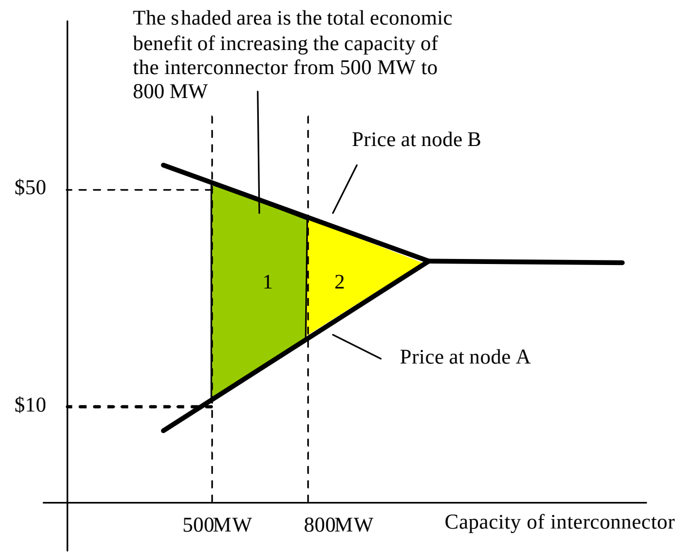
If the interconnector is assumed to have capacity of 500 MW and this limit is binding, then prices in the two regions will separate. The price at node B increases relative to the unconstrained price and the price at node A decreases relative to the unconstrained price.

For example, if the price is $50/MWh at node B and $10/MWh at node A the economic benefit of a marginal increase in the interconnector capacity is the regional price difference of $40/MWh. If capacity was increased from 500 MW to 501MW then 1MWh more can be dispatched for $10 at node A, rather than for $50/MWh at node B. Hence the net economic benefit is the saving of $40/MWh.

The above example is a general result in a simple network without loop flows (and ignoring losses).

This principle does not necessarily hold for larger changes in the interconnector capacity. Larger capacity changes can lead to price changes at nodes A and B. The total economic benefit of an augmentation to the interconnector capacity is no longer the price difference between two nodes. It becomes the area under the curve indicated in figure 3.5.

Figure 3.5 – Benefits of increasing network capacity



In figure 3.5 the interconnector is augmented from 500MW to 800MW. This causes prices at node B to drop and prices at node A to rise. The total economic benefit is the integral of these price differences. That is the shaded area 1, between 500MW and 800MW between the node B price curve and the node A price curve.

If the interconnector were augmented sufficiently, the price at nodes A and B would converge. At this point there would be no further benefit in increasing the interconnector capacity.

An assessment of the cost of out of merit order dispatch of generation inevitably requires some assessment of the marginal cost of supply by each generator. The generator offer or bid, as entered into NEMDE, is considered to be an approximation of the marginal cost for that generator at that point in time.

Therefore one possible approach is to assume that the offers submitted by all generators reflect the marginal cost of supply for the purposes of assessing the total energy cost of dispatch. However in some circumstances the generator's offer is not a good estimate of its marginal cost, for example when the generator exercises market power.

In such circumstances the assessment of the total energy cost of dispatch will be distorted when it is based on the area under the generator's offer curve.

There are alternative approaches for calculating the total energy cost of dispatch, which do not rely on offer curves submitted by generators. Instead some approaches rely on external estimates of each generator's marginal cost. This type of approach does not properly reflect actual outcomes in the market and it requires assessment of generator marginal costs, such as fuel costs, generation capacity and generator reliability. While some of this information is well known and can be verified, other information will require estimation and is subject to error.

3.3.4 Implications for evaluation criteria

The above discussion was about what characteristics should exist if an economic incentive were to be applied. The ACCC has not proposed an economic incentive as part of this draft decision but it presents desirable qualities that should ideally be included in the consideration of the transparency measures. These transparency measures should:

- be related to the economic benefit of the TNSP's action
- depend primarily on actions taken by the TNSPs, with the effects of other parties or random fluctuations muted as far as possible
- rely primarily on information which is publicly available as opposed to information based on estimation.

3.4 Technical principles

Electricity transmission networks provide the pathways for the transport of electrical energy between producers and consumers. They also play a critical role in providing reliable supply across the whole network by diversifying the risk of failures in supply and/or unpredictable spikes in demand.

The networks in the NEM mainly use alternating current (AC), although there are some direct current (DC) links in the network.[11] The ability to directly control the flow of current on AC networks is limited and has implications for the design of transparency measures and for the subsequent development of economic incentives on TNSP's to maximise network capacity.

[11] For example, the Murraylink and DirectLink interconnectors.

On AC transmission networks the capacity of the network to transport energy from one point to another is a function of:

- the physical characteristics of the network (over which TNSPs have some control through investment and network operations)
- supply and demand
- power system operational limitations on the network (over which TNSPs have no control).

The remainder of this sub-section examines the impact of these factors on the capacity of the transmission network and, hence, on the evaluation of transparency measures that capture the market impact of transmission.

3.4.1 Network investment

TNSPs have statutory obligations to develop their networks according to planning standards. These obligations typically require continuous reliable supply even if one or more network elements fail. Most network investment is driven by the need to achieve reliability standards.

However reliability investment also affects the capacity of the network and the market impact of transmission. Reliability investment can, at times, make no difference to the capacity of the network, and could, in some cases, decrease the capacity of the network.

3.4.2 Network operation

TNSPs are able to affect the capacity of the network though their operation.

An aspect of network operations that is visible to market participants is the scheduling and running of planned outages and the occurrence of significant unplanned outages. However, TNSPs can also affect the capacity of the network through other operational actions such as:

- adopting different maintenance procedures e.g. live-wire working, shifting of maintenance into off-peak periods, co-ordinating maintenance with other TNSPs or generators
- investigating network impedance characteristics and risk factors, to enable more accurate specification of the thermal, voltage or stability limits of the network. This could effectively augment the capacity of the network without any physical changes to the assets or their operation
- installing reactive devices or using power electronics so that TNSPs can achieve greater control over the flow of current on the network
- more comprehensive monitoring of network conditions (e.g. ambient temperatures, wind conditions, asset conditions etc.) so the network can be safely operated closer to its actual physical limits; and/or those limits being redefined to be higher than they are now

- entering into network support agreements with generators or interruptible contracts with customers, to enhance the post-contingency capacity of the network.

These and the many other possible operational actions could significantly effect the capacity of the network, which in turn could have significant market impacts.

For example, if there are two parallel transmission lines and one can transfer 20 times as much current as the other, then increasing the capacity of the smaller line by 10MW can lead to an additional 200MW (20 x 10MW) capacity in the larger line. Hence an operational action can have a significant impact on the capacity of the network.

TNSPs already undertake a significant amount of work in these areas, but much of this is work is very complex. In many cases achieving further incremental gains is likely to require investment in time and resources. The full scope for achieving improvements in network capacity through such operational actions is not well understood but it may be significant.

3.4.3 Demand and supply

The pattern of demand and supply affects the existence and extent of transmission constraints.

The pricing arrangements in the NEM mean that when an interconnector is unconstrained, prices in the exporting and importing region converge (with the difference in prices between regions representing transmission losses).

A spike in demand or a failure of generation in the importing region can cause the transmission line to operate above its safe operating limit. In order to ensure that the transmission line is not operated above this limit, it is necessary to constrain-on more expensive generation in the importing region and constrain-off the same amount of cheaper generation in the exporting region.

At such times, the transmission network is having an impact on the market. It is giving rise to higher prices in the importing region and lower prices in the exporting region and preventing the dispatch of the cheapest generation to meet demand.

This constraint and the associated regional price differentials is as much attributable to the transmission network as it is to the excess of cheap generation in the exporting region, or shortfall of cheap generation in the importing region, or excess demand in the importing region. This issue, which was also discussed in section 2.3, suggests that it is difficult to objectively apportion the responsibility for the existence of transmission constraints between consumers, producers and the network.

For example, since 1997 the National Grid Company (NGC) in the UK has been given incentives to reduce the market impact of constraints. Following the implementation of this incentive, constraint costs have reduced considerably, but it is not clear the extend to which this reduction is attributable to actions of NGC or to other changes in the pattern of power flows on the network.

This is an intrinsic feature of electricity networks and has significant implications for the design of a economic incentive.

3.4.4 Power system operation

NEMMCO's role is to operate the interconnected power system within narrow voltage and frequency limits. NEMMCO can apply constraint equations at the time of dispatch that are different to the physical limitations initially advised to NEMMCO by TNSPs. It can do this through the following mechanisms.

- **Constraint formulation:** NEMMCO is required to deliver the least cost of electricity dispatched, with reference to constraint formulation. There have been a range of approaches applied to constraint formulation across the NEM, creating both security and competition issues. Constraint equations are publicly known to all parties. Constraint equations can change when NEMMCO receives new advice from TNSPs regarding appropriate limits for existing network elements.
- **System security:** As a result of assessment of system security factors, NEMMCO may form a different view to TNSPs regarding the appropriate safety margins to be reflected in constraint equations. These differences may arise from:
  - conservative limits being imposed in the absence of specific advice in dealing with ad hoc network outages
  - NEMMCO's transformation of limit equations to linear constraint equations. The form of constraint equation applied will also impact the safety margin required to ensure safe and secure operation of the system.
- **Ancillary services:** NEMMCO is able to use network control ancillary services (NCAS) to enhance network capability where benefits outweigh the costs. Existing linear programming techniques and operational processes do not currently allow automatic dispatch and optimisation of reactive reserve or network loading control (load shedding) for this purpose. It is done manually in accordance with established procedures.

As with changes to network operation arrangements, the potential for improved network capacity through improved system operation arrangements is not well understood.

3.4.5 Implications for evaluation criteria

As discussed, there are many factors affecting the capacity of a transmission network. These include:

- the level of network investment and the design of the network
- network operation and maintenance practices
- demand and supply
- power system operation practices and procedures.

These factors are often not independent of each other. For example, the level of network investment can affect the impact of changes to operation and maintenance practices and vice versa. Also the design and operation of networks can affect system operation procedures and vice versa.

To appropriately take account of these technical features the transparency measures should:

- provide an objective indication of the market impact of transmission
- not make assumptions about the importance of any particular factor affecting the level of transmission constraints, such as generation outages, network outages, demand spikes, system operation procedures
- inform debate on the role of the various factors affecting capacity and their relationship to each other.

3.5 Stakeholder views

Stakeholders have expressed views in submissions on the ACCC's draft decision[12] on service standard guidelines and in presentations, discussions and proposals put forward in working group meetings.

It should be noted that submissions and discussions have generally focused on setting economic incentives rather than on transparency measurement. However given these are closely related it has generally been possible to identify stakeholder's views that are relevant to transparency measurement. This section does not set out stakeholder views on incentive design issues that are not relevant to transparency measurement.

It should also be noted that discussions on service standards have evolved and views attributed to stakeholders may have changed.

This section sets out a summary of stakeholder views. A detailed description of stakeholder views is set out in appendix B.

3.5.1 Summary of stakeholder views

Stakeholders support the principle need for market impact incentives and agree on the need for a better understanding of the nature, cause and impact of binding constraints.

In relation to transparency measures that would be used to assist design an economic incentive, there appears to be general agreement amongst stakeholders that transparency measures should:

- maximise the capability of the transmission system at times of most value to users

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12 ACCC, Draft Decision Statement of Principles for the Regulation of Transmission Revenue: Service Standards Guidelines, 28 May 2003.

- clearly distinguish, to the extent possible, events that TNSPs can control including recognition of force majeure events
- not be volatile
- be generally consistent across TNSPs (however, TNSPs consider that there should be flexibility to account for differences in environmental conditions, operating conditions, existing electricity network configuration and specific TNSP obligations).

There appear to be different stakeholder views about whether:

- the objective of maximising the value to users of transmission capability is consistent with the objective of improving certainty
- transmission outages are important factors affecting inter regional transmission capability compared to other factors
- the focus should be based on cost-based measures (such as short run marginal cost) or price-based measures (spot prices)
- transparency measures should be consistent with the regulatory test
- transparency measures should explicitly focus on defining and measuring best practice for TNSP operations
- implementing some form of transparency measure and incentives is more important than improving understanding of the nature, cause and impact of constraints
- the design of transparency measures and economic incentives should account for benefits from improving certainty. Improved certainty being a reduction in unpredictable changes in transmission capability, which can cause wealth transfers and may increase the cost to end users of managing risk.

The following suggestions were made on transparency measures that could provide useful information to market participants.

- Transparency measures that involved collection and analysis of data for each significant constraint, should explain why the constraint occurred and if there is anything in the future that can be done to minimise the impact of that constraint.
- Arrangements put in place by NEMMCO and the TNSPs to publish forecast transmission outages and the projected market impact of these outages.
- TNSPs to publish more detailed information on the description of factors impacting on line ratings or asset ratings.

3.5.2 Implications for evaluation criteria

Reflecting the areas of stakeholder’s agreement, the ACCC proposes that transparency measures should:

- be directed at market outcomes that benefit users
- encourage TNSP's to maximise the capability of the transmission system at times of most value to users
- to the extent practicable clearly distinguish events that TNSP's can control
- be generally consistent across TNSPs.

3.6 Design principles

There are a number of generally accepted regulatory principles that should apply in the design of an economic incentive[13]. It is appropriate that the development of transparency measures should have regard to these principles since the transparency measures could, if appropriate, assist in the design of economic incentives.

Transparency measures should be based on an objective analysis that can be audited. Using publicly available information and analysis to support the credibility of the measures means that stakeholders are able to verify the measures produced and are able to draw informed, unbiased opinions.

To the extent possible, any transparency measure should be well targeted which, in this context, requires it to clearly relate the cause to its effect. However, as discussed in section 3.5, there are several factors that affect the capacity of the transmission network. Attempting to establish the cause of transmission constraints is likely to be problematic. For this reason, it may not be possible to relate cause and effect using positive analysis, it may require expert discretion.

Transparency measures should be relevant in communicating underlying information. For example, it is known that the incidence of transmission constraints can be uncertain. A measure based on the daily publication of the market impact of constraints might be less useful than the calculation of the market impact of constraints over a longer period.

Administrative complexity, including the costs of data collection and analysis, should be considered. This is an issue not just for the ACCC in compiling and publishing the transparency measures, but also for other parties that may be required to provide data or undertake analysis.

3.6.1 Implications for evaluation criteria

The ACCC propose that the selection of transparency measures should have regard to the following design principles:

- objective analysis that can be audited
- targeted

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[13] See for example: Utility Regulators Forum, Best practice utility regulation discussion paper, July 1999.

- relevance
- administrative feasibility.

3.7 Evaluation criteria

This sub-section lists the proposed evaluation criteria arising from the above discussion about the regulatory framework, economic principles, technical principles, stakeholder views and design principles. The chosen evaluation criteria are that transparency measures should:

- relate the economic benefit of the TNSP's action to the cost
- depend on, as far as possible, the TNSP's action
- be constructed on objective information and analysis that can be audited
- be understandable and unambiguous
- be consistent across TNSPs
- not be based on unsupported assumptions about the importance of any particular factor affecting transmission constraints
- be consistent with the ACCC's code responsibilities.

3.7.1 Relate the economic benefit of the TNSP's action to the cost

This criterion is considered to be consistent with the consensus view among stakeholders (section 3.5). The transparency measures should be directed at market outcomes that benefit users and should maximise the capability of the transmission system at times that provides most value to users.

This criterion is also considered to be consistent with good regulatory practice (section 3.6). An economic incentive should only lead to an improvement in the quality of the service where the economic benefit exceeds the cost of achieving that benefit.

3.7.2 Depend on, as far as possible, the TNSP's action

The rationale for this criterion was discussed in section 3.3 and is widely supported by stakeholders (appendix B).

3.7.3 Be constructed on objective information and analysis that can be audited

The rationale for this criterion was discussed in sections 3.3 and 3.4. While there were some suggestions that arbitrary decisions would be required in the development of an economic incentive, this criterion was generally supported by stakeholders.

3.7.4 Be understandable and unambiguous

The rationale for this criterion was discussed in section 3.6.

3.7.5 Consistency across TNSPs

The rationale for this criterion was discussed in section 3.5. Interpretation of transparency measures is likely to need to take account of a range of different factors that are particular to individual TNSPs.

3.7.6 Not be based on unsupported assumptions about the importance of any particular factor

The ACCC considers that when selecting initial transparency measures it should be cautious about making assumptions that suggest any one factor is more important than others. To do this would risk focussing attention on the wrong factors.

3.7.7 Be consistent with the ACCC's code responsibilities

The proposed transparency measures must be consistent with the code objectives for the regulation of TNSP (section 3.2).

One implication of these criteria is the concept of best practice in defining transparency measures and economic incentives. At this stage, the ACCC does not support attempting to incorporate the concept of TNSP best practice into the transparency measures. The ACCC considers that the definition of best practice in transmission is not tractable. If it was possible to define best practice it would be unnecessary to design incentives intended to reveal what this may be.

It is possible that effective transparency measures (and economic incentives) may provide information that has not previously been available. They also may cause TNSPs to change their practices and procedures in ways that have not previously been considered important or necessary.

Further regulatory practice that defines industry best practice measures and measures the industry's performance against those measures can be intrusive and input-oriented. This is contrary to the ACCC's code obligations to pursue light handed incentive-based regulation. This means defining the objectives that the industry should achieve and leaving it to the industry to find out how best to achieve them.

4. Evaluation of proposed transparency measures

Several proposals for incentive schemes and transparency measures have been presented to the working group for discussion. The various ideas can be classed into two groups. The first group contains suggestions that focus on the market impact of transmission. There are four proposals in this group:

- **Marginal constraint cost (MCC) of outages measure.** This proposal is to publish the MCC of transmission outages. This measure is the sum of the marginal value[14] as estimated by NEMDE for transmission constraints associated with transmission outages. The NEMDE marginal value represents the amount by which the total energy cost[15] would be reduced if the particular constraint was relaxed by a small amount.

- **Two dimensional incentive**. This is a proposal to develop an incentive to maximise the capacity of NEM interconnectors. It is based on the combination of the accumulated price separation across interconnectors (on the x-axis) and the number of hours of binding constraints in excess of an allowed amount (on the y-axis).
- **Transmission maintenance scheduling incentive.** This proposal was based on of the ability of the TNSP to influence the supply and demand balance and the resultant spot price. The proposal aimed to use base load generation plant margin as a proxy for the concentration of generator market power. The TNSP would then be given incentives to prevent increases in market power through its practices in scheduling outages.
- **Total constraint cost (TCC) measure.** This is a proposal to publish the market impact of all transmission constraints based on the cost of being forced to deviate from the least cost dispatch that would otherwise have occurred if the network was unconstrained.

The four proposals are described in appendix A and evaluated against the criteria established in the previous section.

The second group of proposals focus on reporting transmission constraints and on other transmission-specific factors affecting the market. There are three proposals under this category:

- **Tracking of transmission constraints.** A proposal to improve NEMMCO's tracking of transmission constraints.
- **Publication of line ratings.** This proposal would require TNSPs to publish details of how they rate their transmission assets.

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14 NEMDE maximises an objective function subject to a set of constraint equations. Mathematically, the conventional way to solve such problems is to convert them into an unconstrained optimisation problem by multiplying each constraint equation by a lagrangean multiplier. If the constraints are specified in a standard way the lagrangean multiplier can be interpreted as the effect on the objective function resulting from a small relaxation in the constraint.

The NEMDE marginal value is the lagrangean multiplier (lambda) for each constraint equation in the maximisation problem. It usually can be interpreted as the reduction in the total cost of energy that arises from relaxing a given constraint by a small amount.

15 The total energy cost in the case of the NEMDE is the objective function, which includes, the cost of dispatching generation to meet demand and the co-optimisation of the ancillary services markets, amongst other things.

- **Publication of nature of transmission constraints**. This proposal gives a suggestion regarding analysing the nature of transmission constraints on the TNSP's network.

These proposals are also discussed in appendix A.

5. Transparency measures

No single proposal is presently able to meet the criterion established in section 2, as shown in the evaluation in appendix A. However it has been possible to obtain reasonable clarity on the problems to be avoided and of the nature of the further work that should be undertaken.

The ACCC proposes to develop an inclusive set of transparency measures. The ACCC's intention is that the transparency measures should evolve dynamically as new analytical techniques and better information becomes available. This may provide the basis to narrow the focus of these measures in future.

The rest of this section summarises the ACCC's proposal on the publication of two categories of transparency measures.

- Market impact measures.
- Nature of constraints measure.

The proposed measures aim to address most of the concerns expressed by stakeholders. However, there are still concerns that are related to the level of transmission service, which have not been addressed by these measures. This is discussed further in section 6.

5.1 Market impact measures

The ACCC proposes to publish the MCC and the TCC measures in each quarterly transparency report of market impacts (quarterly report). The details of this proposal are based on the ACCC's current modelling capability. However these details may be improved should NEMMCO be able to provide more accurate modelling for these measures.

5.1.1 Total constraint cost

The ACCC intends to report the following details in relation to the TCC measure.

- The TCC for the quarter and previous quarters.
- The TCC of each interconnector for the quarter.
- A graph of the TCC by half-hour intervals during the quarter.
- A summary of the 20 half-hour periods with the highest TCC in the quarter.
- A summary of the five most significant constraint episodes, which may consist of the aggregation of one or more of the 20 half-hour periods of highest TCC.

- An explanation of the events that led to constraints for each of those five episodes.
- A summary of the five half-hour periods with the highest TCC in the quarter, during which there were one or more associated transmission outages.

5.1.2 Marginal constraint cost

At this stage the ACCC can model the MCC of inter-regional constraints (see appendix C) and is considering how to use the NEMDE marginal value field to better estimate the MCC, both for inter and intra-regional constraints.

The MCC measure proposed in the working group was for those constraints associated with outages. The quarterly reports are not intended to be limited to those constraints, rather it will be reported for all constraints.

The ACCC intends to report the following details in relation to the MCC measure. In finalising this report the ACCC will possibly expand upon this consistent with the details reported in relation to the TCC measure.

- The MCC for the quarter and the previous quarters.
- The MCC of each interconnector for the quarter.
- A graph of the MCC by half-hour intervals during the quarter
- A summary of the 20 half-hour periods with the highest MCC in the quarter.

5.1.3 The reporting process

The proposed process for the compilation and publication of the market impact measures will be as follows.

- The ACCC will compile the market impact measures on the basis of the ACCC constraint cost model available to the ACCC (see appendix C). However if NEMMCO's[16] model is ready for use the ACCC would prefer to use the output of NEMMCO's full model rather than its own simplified model. The details of the quarterly report may be influenced by the output of NEMMCO's model.
- The ACCC will include a brief commentary about the circumstances surrounding significant transmission constraints in a draft quarterly report.
- All interested parties will be able to provide submissions on the draft quarterly report. The ACCC does not intend to respond to every submission but it would include, in the quarterly report, additional information provided in submissions, where it is appropriate.

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[16] The ACCC is liaising with NEMMCO to determine whether it can model the TCC measure more accurately than the ACCC's current model. NEMMCO has indicated that it can assist the ACCC, including providing capability to accurately model the TCC of intra-regional constraints, generator ramp rate constraints, etc. The details of this model are still being developed.

- The ACCC would publish the final quarterly report and interested party submissions on its internet site.
- The ACCC will review the process as required.

The ACCC anticipates that this reporting process will be iterative and evolve over time. The evolution is likely to result in amended transparency measures and quarterly report specifications.

5.2 Nature of constraints measure

The ACCC also wants TNSPs to provide information analysing constraints, which the ACCC would use as input to the quarterly reports.

This information will be updated on a quarterly basis and will show results for a rolling twelve-month period. The information should compliment the market impact measures by illustrating the nature of constraints that occurred over the period for each quarterly report . Further details of this proposal are discussed in appendix A.

The ACCC has approached TNSPs to determine what information it can publish in the first instance. TNSPs have jointly volunteered to provide consistent information to meet the ACCC's starting point.

Again the ACCC anticipates that the development of this information would be iterative and evolve over time. It is preferable to for TNSPs to agree and have input to any changes in the information to be published especially on the nature of constraints. The ACCC sees no reason that would stop TNSPs assisting with this process if they are given due consultation.

The nature of constraint information included in the quarterly reports, in the first instance, would be:

- a NEM wide illustration of the intra-regional constraints that had occurred over the quarter and previous periods
- as a NEM wide illustration of the inter-regional constraints that had occurred over the quarter and previous periods.
- an illustration to show the frequency of system normal constraints, planned outage constraints and non-planned outage constraints for each region and interconnectors
- an illustration to show the frequency of constraints that occurred during different load levels for each region and interconnectors
- an illustration to show the frequency of stability, voltage and thermal constraints that occurred for each region and interconnectors
- an illustration to show stability, voltage and thermal constraints that occurred during different load levels for each region and interconnectors.

See appendix D for sample illustrations of the nature of constraints information.

6. Other avenues to meet stakeholder needs

As discussed in appendix B a number of stakeholders stressed the importance of improved certainty of network capacity. It is clear that for many stakeholders the uncertainty of the actual capability of networks, particularly at times of system stress, is of considerable importance.

As discussed above, this uncertainty is impacted by many factors, including TNSP management of transmission outages. However no submissions on the draft service standard guidelines or proposals put to the working group proposed that maximising certainty of transmission service should be an explicit objective or criteria.

The ACCC agrees with observations made by TransGrid and Hydro Tasmania (appendix B) that suggest there may be a conflict between maximising the market value of transmission and maximising the predictability of transmission availability.

There are a number of market design and policy initiatives, either underway or to be commenced, that impact on the certainty and predictability of transmission capacity. Aspects of these initiatives have the potential to affect the relationship between transmission and the wholesale market or to generate information that improves the transparency of transmission. They may, therefore, be relevant to concerns over uncertainty arising from the operation of the NEM. Relevant initiatives include the following:

- The MCE has requested that the AEMC, when established, consider the requirement for, and scope of, enhanced inter-regional trading arrangements in conjunction with the development of the future process for managing regional boundary changes
- The SCO on behalf of the MCE is overseeing an independent review of the existing NEM regional boundary structure
- The MCE has requested the AEMC/NECA consider the requirement and scope for enhanced inter-regional trading arrangements. The request was that this be done in conjunction with the development of the future process for managing regional boundary changes. In doing so, the AEMC has been asked to draw upon existing work of NEMMCO.
- The existing approach to network constraint management is not delivering optimal power system security outcomes. To address this problem NEMMCO has developed a method to re-formulate particularly ineffective constraints as an interim measure only. NEMMCO is to assist the SCO and the AEMC to develop a permanent solution by offering its technical support to ensure that all important factors are considered in the final policy outcome.

These initiatives are either matters of policy concerning the design of the NEM or matters of detailed management of power system security and are the primary responsibility of the respective bodies involved.

The ACCC recognises that uncertainty is also related to the availability of relevant and timely information on the current and future state of the NEM. Improved information on transmission operations is desirable, if it improves the efficiency of the wholesale market and the cost of managing transmission-related trading risks.

The ACCC considers the proposed transparency measures will provide improved information for market participants. However, these transparency measures aim to measure and understand what has happened in the past rather than support predictions as to what will happen in the future.

With regard to a forward-looking assessment of transmission capability, the ACCC notes that NEMMCO has been asked by the MCE to publish ANTS. The purpose of ANTS is to detail the major national transmission flow paths, forecast inter-connector constraints, and identify options to relieve constraints.

The publication of forward-looking transmission capability information relevant to market participants may be closely connected with the ANTS. Options include provision of additional information beyond the transparency measure information or forward-looking information adapted from the transparency measures. The usefulness, practicality and implementation arrangements for these options would need to be further assessed.

The ACCC will continue to consult on whether additional information could be analysed and published in order to improve the efficiency of the wholesale market and lower the cost of managing transmission related trading risks.

7. Next steps

The ACCC aims to release a final report in October 2004 and it intends to use the following process to progress this work.

4 August 2004	Call for submissions
1 September 2004	Submissions close
October 2004	Decision and first quarterly report

Much of this report refers to issues about how the transparency measures could be used as the basis for economic incentives. The assessment of this proposition needs to be undertaken with the assistance of market data and further debate on the associated issues. This additional work, given its possible impact on the market, must be carefully considered by the ACCC before an incentive scheme could be included in the service standards guidelines or in a revenue cap decision.

The ACCC acknowledges the value of market based economic incentives on TNSPs and intends to implement such incentives if it is feasible. However, much detailed technical work remains to be done to develop such an incentive. The ACCC is currently developing a process to take this work forward and it will consider the best way for interested parties to participate in this process. It is expected that some form of consultation process will begin in early 2005.

Appendix A ACCC evaluation

A.1 Marginal constraint cost of outages measure

A.1.1 Description

The proposed measure is the marginal constraint cost (MCC) of transmission outages. The measure is calculated by adding the marginal value of each transmission constraint associated with a transmission outage.

Broadly speaking, the NEMDE seeks to minimise the total energy cost[17] subject to the transmission and other constraints described by mathematical constraint equations. For each constraint NEMDE estimates the constraint's marginal value[18] which is the amount by which the total energy cost would be increased if the binding constraint were to be relaxed by a small amount. In principle the marginal value of each binding constraint provides useful information on the economic benefit of relaxing the constraint by a small amount.

The NEMDE marginal value does not directly measure a change in spot prices and is associated with a constraint violation penalty to each constraint, which exists to ensure that NEMDE can find a dispatch solution.

The penalties are chosen to be large so that constraints are not violated unless there is no other way to provide a dispatch solution. These constraint violation penalties can be up to three hundred times the value of lost load (VoLL), and do not relate to any real impact on the cost of energy in the spot market – since maximum bids are capped at VoLL.

The proposal was to include a ceiling equal to VoLL on the NEMDE marginal value to address this potential problem. To illustrate this, consider the following output of the dispatch engine on the 13th of February 2004. This output focuses on the system normal constraint equation representing the Murraylink interconnector, which is labelled 'S>VML_NIL3'. This constraint bound for 90 five-minute intervals on this day. The following table focuses on a single one-hour period on that day.

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17 NEMDE maximises the objective function subject to a set of constraint equations. Mathematically, the conventional way to solve such problems is to convert them into an unconstrained optimisation problem by multiplying each constraint equation by a lagrangean multiplier. If the constraints are specified in a standard way the lagrangean multiplier can be interpreted as the effect on the objective function resulting from a small relaxation in the constraint.

The total energy cost in the case of the NEMDE is the objective function, which includes the cost of dispatching generation to meet demand and the co-optimisation of the ancillary services markets, amongst other things.

18 The NEMDE marginal value is the lagrangean multiplier (lambda) for each constraint equation in the maximisation problem. It usually can be interpreted as the reduction in the total cost of energy that arises from relaxing a given constraint by a small amount.

Table A.1 – NEMDE marginal value for the Murraylink interconnector

Settlement date	NEMDE marginal value ($/MWh)	Violation degree	SA spot price ($/MWh)	VIC spot price ($/MWh)
13/02/2004 1:00:00 PM	12	0	299	265
13/02/2004 1:05:00 PM	19	0	283	258
13/02/2004 1:10:00 PM	19	0	299	265
13/02/2004 1:15:00 PM	15	0	294	264
13/02/2004 1:20:00 PM	22	0	225	211
13/02/2004 1:25:00 PM	9	0	109	97
13/02/2004 1:30:00 PM	14	0	245	216
13/02/2004 1:35:00 PM	21	0	236	215
13/02/2004 1:40:00 PM	30	0	299	264
13/02/2004 1:45:00 PM	200,000	-32	288	260
13/02/2004 1:50:00 PM	200,000	-46	237	210
13/02/2004 1:55:00 PM	13	0	140	123
13/02/2004 2:00:00 PM	10	0	140	123

In the first 40 minutes the constraint bound with a low marginal cost. This was followed by ten minutes in which the constraint was violated and a marginal value of $200,000/MWh. Then the marginal value returned to previous levels. Under this approach, the marginal value would be added, with a cap of $10,000/MWh, leading to a value of $20,154.53/MWh for this hour.

A.1.2 ACCC evaluation

Criterion	Evaluation
Relate the economic benefit of the TNSP's action to the cost	The proposed approach is based on the sum of the NEMDE marginal value of each binding constraint over an interval. In principle, the marginal value of the constraint could represent the true economic benefit from a small relaxation of the constraint. However, as discussed earlier, NEMDE mixes the true marginal cost with the constraint violation penalties. Separating these two effects is difficult. It is also difficult to be certain that relieving a constraint with a marginal cost of $10,000 would yield a greater benefit than relieving a constraint with a marginal cost of $1,000. As discussed earlier, a measure of the cost of a constraint at the margin provides little insight into the importance of that constraint further away from the margin. For example, a constraint which has a marginal cost of $1,000 might be relatively easily reduced to zero with a very small increase in capacity (and therefore would be economically beneficial to alleviate) while another constraint, with a marginal cost of $9,000 might require a substantial increase in capacity to alleviate (and therefore should not be alleviated). In other words this measure is not directly related to benefit of completely relieving the constraint it therefore potentially sends poor signals regarding the most efficient action. The proposal does not score well on this criterion.
Depend on, as far as possible, the TNSP's action	As discussed above, this approach is based on the output of the NEMDE. The output of the NEMDE depends not only on the actions of TNSPs, but also on the bids submitted by generators and on weather patterns. An action taken by the TNSP to alleviate a constraint may have little impact, depending on weather, bids and the actions of other TNSPs. On the other hand, the failure of the TNSP to take action may have a significant impact, depending, again, on the weather, bids and the actions of other TNSPs. The link between the actions the TNSP and the measure is therefore, at best, indirect. At this stage the extent of the linkage between the TNSPs actions and market outcomes remains unclear. It is likely that over time the TNSP would develop tools that allow it to predict the expected or likely outcome resulting from its action. The proposal scores relatively low on this criterion.
Be constructed on objective information and analysis that can be audited	This approach relies exclusively on output of NEMDE, which is already published. The proposal scores well on this criterion.

Criterion	Evaluation
Be understandable and unambiguous	The marginal constraint cost is a concept that is easy to understand. However, as discussed earlier, this approach suffers from the drawback that the output of NEMDE mixes the true marginal cost with the constraint violation penalties. Separating these two effects is difficult. As a result it is difficult to be certain that a constraint which has a NEMDE marginal cost of $10,000 is, in fact, more significant than a constraint which has a NEMDE marginal cost of $1,000. Furthermore, as discussed earlier, a measure of the marginal constraint cost provides little insight into the importance of that constraint further away from the margin. A constraint which has a marginal cost of $1,000 could be relatively easily reduced to zero with a very small increase in capacity while another constraint, with a marginal cost of $9,000 might require a substantial increase in capacity to alleviate. For these reasons, it is difficult to assess or interpret the significance of the proposed measure and the proposal does not score well on this criterion.
Be consistent across TNSPs	This approach treats all constraints consistently. The proposal scores well on this criterion.

Criterion	Evaluation
Not be based on unsupported assumptions about the importance of any particular factor affecting transmission constraints	This proposal, by focusing exclusively on the economic harm brought about by a constraint, does not rely on assumptions regarding the importance of constraints at different times, or of different durations. However, the approach distinguishes outage constraints from system normal constraints. This approach was supported by a number of stakeholders who suggested that the economic impact of outage constraints should be distinguished as part of a transparency measure and that this should be a primary focus of a market impact transparency measure. The ACCC agrees that in many cases it would be advantageous to focus the transparency measure on specific actions as far as this is possible and is consistent with the criterion – the measure should be related to the actions of the TNSP. However, the ACCC is not convinced that a specific focus on outage constraints is appropriate at this stage. Views appear to differ on the market impact of network outage constraints. For example, TransGrid suggested that while a significant proportion of network constraints could be related to network outages, the market impact of these network outage constraints was relatively insignificant. Furthermore, the proposal attributes the full market impact of a transmission constraint that occurs when there is a network outage, to that outage. As discussed in the section on economic and technical principles, there are several factors that affect the existence and market impact of transmission constraints. The proposal does not score well on this criterion.
Be consistent with the ACCC's code responsibilities.	This approach uses publicly available information. No inference is drawn between the information and the performance of any TNSP. The publication of this information appears to be consistent with the ACCC's code obligations. The proposal scores well on this criterion.

A.2 The two–dimensional incentive

A.2.1 Description

This proposal was submitted to the working group as a straw man idea for consideration. It was proposed as an untested generic framework.

The basis of this proposal is that interconnectors bind at transfer levels below their nominal capability because there is no obligation and/or incentive to for any participant to procure services that would support interconnector capability. The proposed mechanism aims to provide the necessary incentive.

The proposal is that rewards/penalties for maximising the availability and capacity of interconnectors could be based on a two-dimensional performance measure. This proposal combines the following two measures.

- A measure of capability demerits, which was the extent of interconnector capability restriction. This was based on the number of hours that the interconnector capability was below the target capability.
- A measure of market impact demerits, which was the extent of the market impact of transmission. This was based on the cumulative total of the price separation across the interconnector. The accumulation of settlement residues[19] was a suggested alternative.

The proposal envisages that capability demerits and market impact demerits could accrue independently of each other. Alternatively it would be possible to ensure that demerits would only accumulate on either axis if the length (or degree) of an outage exceeded a certain threshold and market impact exceeded a certain threshold.

Rewards would apply only if performance was good against both dimensions of capability demerits and market impact demerits. Penalties would apply if performance was poor against both dimensions. The framework also allowed for the accumulation of demerits even though outages occurred for only a brief period of time.[20]

The proposal is perhaps best defined as an incentive rather than a transparency measure. But the fundamental ideas could be used as a transparency measure.

A.2.2 ACCC evaluation

In order to implement a scheme such as that proposed in the 'Straw man', the following conditions must be met.

- TNSPs must have the responsibility to procure the full range of services capable of influencing network capability. At present, these responsibilities are diffused, that is NEMMCO is responsible to procure network control ancillary services and TNSPs are responsible for grid support arrangements. In many instances the distinction between these services is artificial, although the range of technologies NEMMCO and TNSPs can apply to the issue is vastly different.
- Nominal interconnector capability must be established. At present there is no specific link between assumed transfer capabilities that underlie analysis conducted for the regulatory test – the basis upon which approval to construct an asset and recover the costs of the asset – and an obligation to deliver (at least) capability broadly consistent with those assumptions.

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19 Settlement residues across interconnectors are defined to be the half the difference between the importing region price and exporting region price ($/MWh) multiplied by the flow (MWh) over the interconnector.

20 There was also scope for a combined measure of market impact when the accumulation of demerits is considered problematic. This involved using the product of capability restriction and market impact.

- Responsibility for individual interconnectors (and flow directions) must be clearly assigned to TNSPs either individually, jointly or collectively. Given that none of the above conditions apply at present, the straw man as proposed cannot, at this stage, be taken forward.

Nevertheless, for the sake of completeness, the ACCC's evaluation of this approach follows.

Criterion	**Evaluation**
Relate the economic benefit of the TNSP's action to the cost	Unlike the marginal cost of constraints measure, the two-dimensional measure uses actual prices observed in the market and therefore is not distorted due to constraint violation penalties. However like the marginal cost of outages measure, this proposal relies in part on a measure of impact based on the difference in prices, when constraints over interconnectors bind. As discussed above, such price differences do not directly relate to the economic benefit of completely relieving constraints. The use of this measure therefore potentially sends wrong signals regarding the most efficient action. The proposal does not score well on this criterion.
Depend on, as far as possible, the TNSP's action	Like the other proposed market-impact measures discussed in this section, there is no direct link between the actions of the TNSP and their market impact. However the idea of also monitoring the extent of interconnector transfer capability restriction is more closely related to TNSP actions then the other market impact measures. That is it may also provide a more focussed assessment of the actions of TNSPs that effect capability of interconnectors. Such capability restrictions may not necessarily adversely impact market outcomes. The proposal does not score well on this criterion.
Be constructed on objective information and analysis that can be audited	The calculation of market impact demerits would be based on objective and public information. This part of the proposal scores well on this criterion. The calculation of capability demerits requires a subjective assessment of the capability of interconnectors (in particular assessment of the length of planned and forced outages). This part of the proposal does not score well on this criterion.

Criterion	Evaluation
Be understandable and unambiguous	There are a few options in this proposal such as whether capability and market demerits should accrue independently of each other. And whether market demerits should be based on the accumulated price separation across interconnectors or the accumulated settlement residues. These options do not make the overall framework significantly harder to understand. As an overall framework the proposal scores well against this criterion. Like the marginal cost of constraint measure, the market impact demerits is based on a calculation of the difference in prices. In this regard it is difficult to assess or interpret the significance of the proposed measure. The proposal does not score well on this criterion.
Be consistent across TNSPs	The calculation of the capability demerits could be affected by discretionary decisions on the appropriate target level of availability. However the calculation of the market impact demerits would be consistent for all interconnectors. The proposal scores well on this criterion.
Not be based on unsupported assumptions about the importance of any particular factor affecting transmission constraints	This proposal does not rely on arbitrary classifications of constraints – it makes no distinction between types of constraints. The proposal scores well on this criterion.
Be consistent with the ACCC's code responsibilities	The information on which publication of both market impact demerits and capability demerits would be derived appears consistent with the ACCC's code obligations. The proposal scores well on this criterion.

A.3 Transmission maintenance scheduling incentives

A.3.1 Description

This proposal was based on the ability of TNSPs to influence the supply and demand balance and the resultant spot price. This proposal aimed to use base load generation plant margin as a proxy for the concentration of generator market power. The TNSP would then be given incentives to prevent increases in market power through its practices in scheduling outages.

The proposal was complex and not well developed. However the following would have to be achieved as part of the proposal.

- A benchmark of short run marginal cost for generators.
- A benchmark interconnector capability.
- Four zones that depended on the market impact.
- Market impact thresholds.

A.3.2 ACCC evaluation

This proposal is not in a well articulated form and is quite complex, which makes it very difficult to understand how the proposed incentive mechanism works. Nevertheless a brief evaluation against the criteria is given below.

Criterion	Evaluation
Relate the economic benefit of the TNSP's action to the cost	This proposal does not appear to relate the benefit of the TNSP's action to its costs. Rather it assumes that the TNSP's planned outages are the key to providing incentives to minimise generator misuse of market power. This implicitly assumes that planned outages are the cause of generator market power. The proposal does not score well on this criterion.
Depend on, as far as possible, the TNSP's action	This measure of market impact the concentration of market power would not only depend on how TNSPs planned outages. But also it would depend on the market structure, network design, network configuration and the location of load, etc. The proposal does not score well on this criterion.
Be constructed on objective information and analysis that can be audited	Setting the required benchmarks for this proposal would require expert discretion and to an extent would be subjective. The proposal does not score well on this criterion.
Be understandable and unambiguous	It is difficult to understand this proposal other than at a concept level. It is complicated and requires detailed analysis to understand a simple example. It would be more difficult and less understandable to implement such a scheme in practice. It would also be difficult to interpret the measures should they be used as transparency measures. The proposal does not score well on this criterion.

Criterion	Evaluation
Be consistent across TNSPs	This proposal as mentioned above would require expert discretion to set benchmarks. To that extent it would not be consistent across TNSPs. Given the complicated nature of this proposal it is not possible to conclude that the framework could be applied consistently, even if the proposal was only used as a transparency measure. The proposal does not score well on this criterion.
Not be based on unsupported assumptions about the importance of any particular factor affecting transmission constraints	This proposal relies on the assumption that planned transmission outages are the most important factor that affects the level of generator market power and in turn have a large market impact. This assumption is not supported as there would be many factors that affect the level of competition amongst generators. The proposal does not score well on this criterion.
Be consistent with the ACCC's code responsibilities	This proposal appears to promote competition upstream of the transmission network. To this extent it is consistent with a principle of the code that the ACCC must apply when setting revenue caps. However it may also be considered heavy handed given the detailed outage planning information required and the detailed benchmarking approach. It is not possible to state whether this proposal would be considered consistent with the ACCC's code responsibilities.

A.4 Total constraint cost measure

A.4.1 Description

The economic benefit of the TNSP's action to increase the capacity of the network can be measured by the change in the total energy cost of dispatch due to that action. That is the total cost of dispatching sufficient generation to meet demand before and after the action by the TNSP.

Hence the TCC for a given network configuration can be defined as the difference in the actual total energy cost of dispatch for that network and the estimated total energy cost of dispatch for a network assuming it had no binding constraints.

Changes in the TCC are the same as the economic benefit as defined above. The economic benefit from an action is equal to the total energy cost without the action less the total energy cost after the action. As shown in equation A.1.

Equation A.1

Economic benefit = TEC* (before) - TEC (after)

* TEC = total energy cost

Under the approach proposed here, the TCC for a given network configuration is equal to the total energy cost for that configuration less the total energy cost of a hypothetical unconstrained network, shown in equation A.2.

Equation A.2

TCC = actual TEC – TEC assuming no constraints

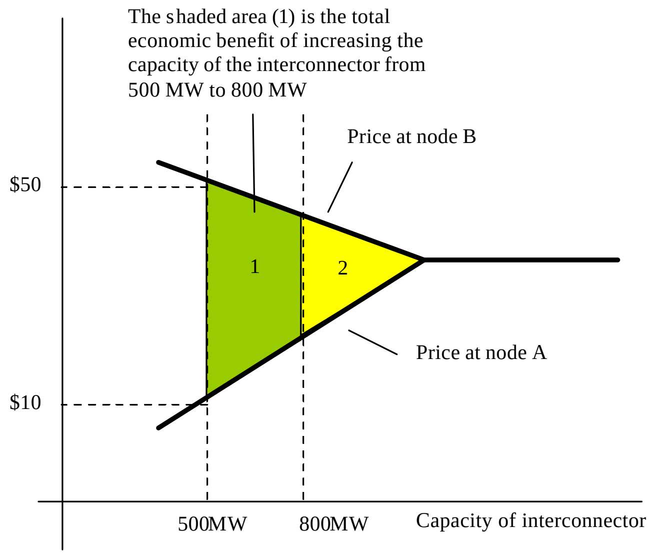
Hence the change in the TCC due to the TNSP's action is equal to the economic benefit of the change in the total energy cost due to the change in transmission capacity.

Equation A.3

TCC (before) – TCC (after)	=	[TEC (before) – TEC (unconstrained)] –
		[TEC (after) – TEC (unconstrained)]
	=	TEC (before) – TEC (after)
	=	economic benefit

This is illustrated in the figure A.1. The TCC before building out the interconnector from 500 MW to 800 MW is area 1 plus area 2. The TCC after building out the interconnector is reduced to just area 2. The economic benefit of building out the interconnector is (as before) the difference between these two areas, which is just area 1.

Figure A.1 – Benefits of increasing network capacity



This measure suggests that the total energy cost be calculated, in the first instance, on the basis of the actual supply curves bid by generators. Further analysis will be needed to assess whether or not this is a reasonable approximation.

A full and accurate calculation of the total energy cost with and without certain constraints requires taking into account all the potential constraints which could affect this dispatch (including ancillary services, ramp rate constraints and so on). It appears that the most reliable method for doing this is to re-run NEMDE with and without the relevant constraint equations.

The ACCC has developed a constraint cost model that is a simplified version of NEMDE, which is described in appendix C.

A.4.2 ACCC evaluation

Criterion	Evaluation
Relate the economic benefit of the TNSP's action to the cost	This measure is designed to reflect the economic benefit of relieving all network constraints. Changes in this measure are equal to the economic benefit of relieving a constraint by a certain amount. A TNSP which was rewarded dollar-for-dollar for changes in this measure would have the economic incentive to relieve constraints only if the economic benefit exceeded the cost. However, the calculation assumes that generator bids would remain unchanged with and without transmission constraints. In some cases this assumption does not hold. However further work is required to determine if this assumption is generally true. Without further work this proposal does not score well on this criterion.
Depend on, as far as possible, the TNSP's action	Like the MCC measure, the TCC measure is based on NEMDE output, which depends on factors other than the TNSP's action such as generator bids and weather patterns. The TNSP's action to relieve a constraint may have little market impact depending on these other factors. On the other hand, a failure of the TNSP to act may have a significant market impact, again, depending on these other factors. Therefore the link between the TNSP's action and the TCC measure is, at best, indirect. At this stage the extent of the linkage between the TNSPs action and its market impact remains unclear. It is likely that over time a TNSP would develop tools that allow it to predict the expected or likely outcome resulting from its actions. The proposal does not score well on this criterion.

Criterion	Evaluation
Be constructed on objective information and analysis that can be audited	This approach calculates the change in the total energy cost of dispatch with and without network constraints. This is calculation is not currently published by NEMMCO. However the calculation can be audited and the inputs required for this calculation are the same as those required by NEMDE. The proposal scores well on this criterion.
Be understandable and unambiguous	Measuring the cost of constraints as the change in the total energy cost of dispatch is an idea which is intuitively simple. The measure can be compared to similar figures derived, for example, for the purposes of carrying out the regulatory test. The proposal scores well on this criterion.
Be consistent across TNSPs	This approach treats all constraints consistently. The proposal scores well on this criterion.
Not be based on unsupported assumptions about the importance of any particular factor affecting transmission constraints	This proposal focuses on the economic harm of constraints and does not rely on assumptions regarding the importance of constraints at different times, or of different durations. In this respect, the approach scores well against this criterion. The proposal scores well against this criterion.
Be consistent with the ACCC's code responsibilities	This approach uses publicly available information. No inference is drawn between the information and the performance of any TNSP. The publication of this information appears to be consistent with the ACCC's code obligations. The proposal scores well on this criterion.

A.5 Proposal to improve tracking of the cause of constraints

A.5.1 Description

This proposal was that NEMMCO should develop systems and procedures to support the introduction of market impact incentives for TNSPs.

This proposal is based on the idea that it is essential to identify the relationship between network operation and the constraint equations used for dispatching the market. NEMMCO was proposed as the party to track the constraints because:

- it has full access to all information that can cause constraints

- it is the only party privy to its decisions to apply constraint equations in response to information about the power system.

The proposal suggests that efficient identification of constraints can be achieved by implementing some simple changes to existing NEMMCO systems and procedures. The specification of the changes proposed to improve the tracking of constraints is not clear.

The proposal was clear that one change would involve the addition of a field in NEMDE that identifies why constraints are invoked. This identification field could be an outage identifier assigned to each planned outage request.

A.5.2 ACCC evaluation

At this stage the ACCC does not have a view on whether NEMMCO's existing constraint tracking arrangements could be improved. This type of further work may be beneficial. However before a meaningful assessment of this proposal can be made, the proposal must be better understood. The ACCC understands that a member of the working group has undertaken to discuss this idea with NEMMCO.

The ACCC considers it appropriate to understand the relationship between network operation and constraints to assist in developing incentives based on the market impact of transmission. However there may be other views on this issue.

Often it may be desirable to understand cause and effect of constraints but this is not necessarily the case in incentive regulation. That it is not necessary to separate factors within the control of the TNSP from factors outside the control of the TNSP to encourage efficient outcomes. This philosophy underlies the ACCC's approach to the design of the incentive regulation for capital and operating expenditure by TNSPs. It may be the case that the same philosophy could be effective in the design of market impact incentives.

A.6 Publication of line ratings

A.6.1 Description

This proposal is to publish information about how TNSPs determine the capability (rating) of the transmission network elements.

The National Generators Forum (NGF) and the Energy Retailers Association of Australia (ERAA) made a joint submission[21] to the ACCC in relation to the service standards guidelines. This submission was presented to the working group and was followed by this proposal.

The proposal covered four areas.

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21 NGF/ERAA, Joint submission regarding the ACCC draft transmission service standards guidelines, 14 July 2003.

- Component ratings for given ambient conditions – TNSPs to provide details of each component that had a line rating less than that set by the components manufacturer.
- Selection of ambient conditions as a basis for ratings –TNSPs to provide details of each component where ambient conditions were used to set the rating and to explain what economic evaluation they had undertaken to make that decision.
- Treatment of post-contingency loading –TNSPs to provide details of each component for which a short term rating was available when a contingency event occurs and to explain what economic evaluation they had undertaken to make that decision.
- Network stability limits –TNSPs to provide details about each component that had stability limits and the economic evaluation they had applied to assess whether each stability constraint could be lifted.

TNSPs considered this proposal and concluded that:

- the line rating proposal required an onerous amount of information to be collected
- such an information gathering process would be highly inefficient
- many of the plant ratings requested do not have a material market impact.

In addition TNSPs noted alternative solutions could be workable. In particular they noted that:

- TNSP input into the quarterly transparency reports could provide relevant plant rating information for constraints identified as problematic
- a TNSP cooperation charter had been established that will report to the market in July 2004, which will be followed by constraints workshop held later in the year
- they would assist additional line rating information requests from participants, subject to liability, insurance and security issues.

Through the TNSP cooperation charter, TNSPs have also voluntarily committed to:

- maximise plant rating and limits using dynamic ratings
- provide information to the market about constraints
- invest to relieve constraints, where economic
- identify and minimise the market impact of constraints.

A.6.2 ACCC evaluation

It is understandable that market participants should seek high quality asset rating information. Specifically, the ACCC recognises the concern that TNSPs have discretion in setting line ratings and that the choice of different line ratings can have a significant market impact.

In the current regulatory framework TNSPs receive little, if any, benefit from increasing line ratings. This is of most concern when a particular line is constrained and causes adverse market impacts by requiring out of merit order dispatch of generation. It may not be possible to increase the line rating but the concern is that TNSPs have no incentive to consider the possibility.

The publication of information about the line rating practices of different TNSPs could provide an opportunity for comparative assessment and may lead to the more rapid transfer of best practice amongst TNSPs. However line rating is a complex subject and it would be important to ensure that appropriate information is collected so that it will be useful. It would also be important to ensure that publishing such information does not unnecessary burden TNSPs or threaten the security of the power system.

The ACCC recognises TNSPs concerns with the provision of information in the form proposed. In response to discussions with the ACCC, TNSPs have undertaken to provide appropriate line rating information to market participants as follows.

- An initial progress report from the plant rating working group (established under the TNSP cooperation charter) will be published in July 2004. The ACCC understands that the report will include the group's charter, a summary of work already completed, broad conclusions, objectives for future work, and a forward program of work. Further progress reports would be issued by the TNSPs at six monthly intervals.
- Rating workshops will be conducted by TNSPs later in 2004 (similar to Annual Planning Report public forums and constraint workshops that have been held in most regions). Ratings workshops would explain rating methodologies and provide examples of how to obtain continuous ratings for particular lines.
- Appropriate additional information on the rating of specific network elements will be provided in response to bona fide requests from market participants.

The ACCC believes that the TNSPs' alternative to publishing line ratings adequately addresses the concerns underlying this proposal. The ACCC will assess the success of these arrangements in the future.

A.7 Publishing information about the nature of constraints

A.7.1 Description

TransGrid presented to the working group an overview of its analysis of network constraints. This was done to help to inform the debate about the nature of transmission constraints. The presentation did not measure the market impact of constraints but it provided a background to different types of network constraints and quantified their respective influence by monitoring the number of 5-minute dispatch intervals during which constraints of that type applied.

A.7.2 ACCC evaluation

Much of the information TransGrid provided about the nature of constraints has also been provided by other TNSPs. The ACCC considers that while this information is not focussed on the market impact of constraints it provides useful insight about the existence of various constraints. It also provides information on the nature of those constraints such as whether they occurred at times of network outages or forced outages, whether they relate to voltage, thermal or stability limits.

The ACCC met with TNSPs to consider whether it was possible and if so, how, a co-ordinated publication of constraint information could be done. As a result of this TNSPs have undertaken to produce the following information.

- Total number of 5-minute dispatch periods in the NEM when there is a binding constraint, with the total also broken up into intra-regional constraints for each region and the number of inter-regional constraints between each region.
- Total number of 5-minute dispatch periods in which a constraint occurs shown on a monthly basis broken down into constraints that resulted from planned outages, non-planned outages and other constraints.

  Reporting of constraints due to outages would, for the case of regional constraints, need to include constraints due to outages in and out of the region. Also the allocation of outages into the categories would be made on the basis of engineering judgement, not on the basis of NEMDE re-runs. And in the case of interconnector constraints, the relevant TNSPs would agree on the classification of the constraints.
- Total number of 5-minute dispatch periods in which a constraint occurred for the twelve-month period (or applicable shorter period before June 2005). This would be plotted against load level for the region. The load to be used for each constraint period is the total load at the time of the constraint. In the case of interconnector, the load to be used is the load at the time in the importing region.
- Total number of 5-minute dispatch periods in which a constraint occurred, shown on a monthly basis broken down into stability, voltage, and thermal constraints.
- Total number of 5-minute dispatch periods in which a constraint occurred for the twelve-month period (or applicable shorter period before June 2005). This would be plotted against load level for the region and broken into stability, voltage, and thermal constraints. The load to be used for each constraint period is the total load at the time of the constraint. In the case of interconnector, the load to be used is the load at the time in the importing region.

Appendix B Stakeholder views

B.1 Introduction

This appendix reviews stakeholders' views about transmission service incentives and transparency measures. A summary of stakeholder views is set out in section 3.5.

B.2 Need for market impact incentives

In general all stakeholders support the need for market impact incentives. Factors that contribute to this view include:

- the need for a clear link between service standards and network charges
- growth in customer demand leading to increased intra regional congestion and the need for efficient investment in the market by generation, transmission, demand side or other initiatives
- limited focus of the current service standards guidelines.

There is a common view emphasising the important link between service standards and network charges. ERAA/NGF[22] noted 'performance standards in conjunction with code and jurisdictional regulatory instruments define the level of service that is provided for the payment of network charges'

All stakeholders recognise that it would be inefficient for TNSPs to relieve all transmission constraints. ERAA/NGF[23] noted that:

> … increased congestion will need to be addressed by efficient investment in the market by generation, transmission, demand side or other initiatives. Hence transmission investment and operation cannot be separated from the market but rather are part of the deregulated market for electricity. It is therefore essential that TNSP performance measures and incentives ultimately reflect the market impact of TNSP activities.

There is agreement that the existing service standards guidelines have a limited focus and do not take account of market impacts. For example ERAA/NGF noted that some circuit failures have much greater market impacts than others whereas the current service standards incentives place equal weight on circuit availability regardless of market impact.

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22 NGF/ERAA, Joint submission regarding the ACCC draft transmission service standards guidelines, 14 July 2003.

23 ibid.

B.3 Benefits to electricity users.

There is agreement that any economic incentive (and transparency measure) should be directed at market outcomes that benefit electricity users. In other words the measures should be directed at maximising the market value of the capability of the transmission network, which includes focussing on time periods when performance matters.

A number of stakeholders have, in discussions, emphasised that users benefit from improved certainty. This implies that economic incentives (and transparency measures) should focus on reducing the impact of unpredictable changes in transmission capability, which otherwise bring about wealth transfers and increase the risk management costs of end users.

It should be noted that written submissions have not proposed this as an explicit objective of an economic incentive. While stakeholders generally understand the impact of uncertainty, there are different views on whether it can or should be taken into account.

There are also different views on whether benefits to users should be assessed based on cost-based or price-based measures.

B.4 Need to improve certainty

A number of stakeholders believe that there is a need to improve certainty about the TNSPs management of transmission outages. There appears to be a fairly common view that it is both important and possible to reduce the impact of unpredictable changes in transmission capability.

However, TransGrid suggested that the elimination of all transmission outages would not remove the uncertainty associated with interconnector capability. TransGrid considers that much of this uncertainty arises even with all transmission elements in service.

B.5 Improving certainty vs maximising transmission capability

There has been significant debate about the appropriate focus of economic incentive design and by implication, transparency measurement. During this debate, some stakeholders considered that the objectives of improving certainty and maximising capability are in conflict. TransGrid[24] noted that:

> Some market participants value the predictability of future outages as being more important (than maximizing the value of transmission capability) because it enables them to enter into hedging arrangements for the future with greater certainty. Other participants, however, clearly support the notion that TNSPs should reschedule outages, when such outages create 'significant' price separation between regions, or require generators to be constrained on or off, especially in times of high prices.

[24] TransGrid, Submission – Draft Decision: Service Standards Guidelines, 16 July 2003

Transgrid further noted that the review of integrated energy market network services (RIEMNS) provide a passive role for TNSPs planning outages. It suggested that these code changes indicate that the market prefers certainty about transmission outages.

Similarly, Hydro Tasmania stated[25]:

> The development of meaningful market impact measures requires market participants to be clear on whether they are seeking to minimise market impact by having a level of certainty regarding transmission outages (so that participants can hedge their positions in the market) or alternatively responsiveness to reschedule outages at short notice in response to an appropriate market impact.

B.6 Cost-based vs price-based measures

There are differences of view as to whether incentives should be based on cost-based measures (such as short run marginal cost) or price based measures (pool prices). Generators and retailers face costs that are determined by pool prices and some commented that incentives (and transparency measures) should reflect price differences. TNSPs on the other hand considered that the incentives (and hence transparency measures) should focus on costs.

Electranet SA noted that the definition of market benefit in the regulatory test[26] does not include minimisation of pool price differences (competition benefits). Any mismatch between the regulatory test and economic incentives could lead to mixed signals for TNSPs and interested parties.

TransGrid considers that inter-regional pool price separation is a better indicator of short term market power involving transfers of wealth from customers to generators than net economic impacts.

B.7 Events that TNSPs can control

There is a widespread agreement that, ideally, an economic incentive (and transparency measures) should be based on measuring factors that the TNSP can either control or can manage. This includes exclusion of force majeure events.

TNSPs strongly hold this view. For example Powerlink[27] stated that:

> …any incentive scheme must only recognise those market impacts influenced by the actions or omissions of the TNSP: an incentive scheme that applied penalties without regard to a TNSP's ability to effect the market impact would do nothing to alter TNSP behaviour.

Hydro Tasmania considered that an effective economic incentive should separate out the costs that TNSPs are best able to influence from those that NEMMCO is best able to influence. Further it should separate out the costs that each TNSP is individually best able to influence.

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[25] Hydro Tasmania, Draft Service Standards Guidelines Submission, 18 July 2003 .

[26] ACCC, Regulatory Test for New Interconnectors and Network Augmentations, 15 December 1999.

[27] Powerlink, Issues for Service Standards Working Group - QNI Example, 30 March 2004.

TNSPs were also concerned with short run timing issues. They considered that any economic incentive (and transparency measure) should establish a meaningful relationship between the timeframes over which they manage their activities such as transmission outages, and the valuation of the market impact.

TransGrid[28] for example noted that pool prices have proven unhelpful because of the rebidding that occurs after the TNSP has committed resources to a planned outage. Pre-dispatch prices do not measure economic benefits and would be very disruptive and costly for TNSPs to respond to. Similarly, Electranet SA noted that market impact is measured in five minute dispatch intervals whereas the timeframe within which the TNSP is capable of responding is much longer (normally hours).

These views appear to imply that, ideally, the relevant price signal is some forward price signal related to the lead time the TNSP has for taking actions to control transmission capability. TransGrid suggested that the settlement residue auction prices could be used as a forward price signal of the periods in which to avoid planning outages.

There is widespread agreement that any economic incentive should recognise force majeure events, although there are different views on the definition of force majeure.

B.8 Not be volatile

There is widespread agreement that, ideally, transparency measures should not be highly volatile. Volatility makes it more difficult to design an effective economic incentive that measured actual performance against a benchmark level of performance, which is linked to the TNSP’s revenue cap.

B.9 Consistency across TNSPs

There appears to be general support for an incentive (and therefore transparency measures) that are consistent across all TNSPs in the NEM with measures that are generally the same for all TNSPs. EERA/NGF take the view that the full range of standards should be applied to all TNSPs responsible for the provision of services.

TNSPs, while generally supporting consistency, consider that some flexibility in the interpretation of performance measures is required to account for factors such as:

- differences in environmental conditions
- differences in operating conditions (e.g. it may be more difficult to schedule outages for sustained high loads compared to ‘peaky’ load curves)
- existing electricity network configuration (e.g. compact meshed network vs long geographically dispersed networks)
- specific TNSP obligations

[28] Transgrid, Submission – Draft Decision: Service Standards Guidelines, 16 July 2003

- differences in levels of construction (high levels of construction works may require higher levels of outages).

EERA/NGF while recognising TNSPs have to deal with location specific issues, considered that those issues are generally known in advance of construction and allowed for in the design of assets. They suggested that the costs upon which the ACCC based its revenue cap decisions already contain an allowance for these different factors.

B.10 TNSP best practice

A number of stakeholders believe that economic incentives should be set relative to some best practice benchmark for TNSP operations (as distinct from designing an incentive that does not explicitly involve defining best practice operations but encourages TNSPs themselves to move towards best practice).

For example, the EERA/NGF[29] proposed:

> …(the service standards should) focus on ensuring the best performer in each category has a small improvement to make during the term of the standard and the remainder have a real target. This could be achieved by setting each standard at the 80th percentile for the beginning of a defined period and increasing the standard to the 110th percentile by the end of a period. This approach will allow good performers to be immediately rewarded while still requiring improvement during the regulatory period. We acknowledge that this approach may be difficult immediately but must be applied when the market-based measures are incorporated since the market based performance outcomes should be the same in all locations.

B.11 Priority for implementation

It is widely understood that the transmission systems are complex and that there are benefits in gaining a more detailed understanding of the nature and impact of transmission system operations. There is therefore agreement on the need for further analysis and research to enable a better understanding of the nature, cause and impact of binding constraints. However there were different views as to the priority on moving ahead with implementation as compared to the priority on research.

The EERA/NGF suggested initiatives they believed could be implemented quickly and can be reached easily. Others stressed that priority should be given to undertaking more work. Electranet SA for example noted that the impediments that must be overcome including a lack of data identifying the cause of binding constraints and demonstrating any link with TNSP behaviour; and finding an appropriate and practical way of assessing the market impact of any binding constraints caused by TNSP.

B.12 Specific views on transparency measures

There appears to be general agreement that the use of nominal capacity is not a meaningful measure because of changes in the pattern of demand and supply.

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29 NGF/ERAA, Joint submission regarding the ACCC draft transmission service standards guidelines, 14 July 2003.

There is a wide spread view that an important focus for the design of any economic incentive (and hence transparency measures also) should be to identify the economic benefits of changed TNSP outage timing. However, as noted earlier, Transgrid questioned this, noting that outage timing is not a major factor affecting interconnection performance.

Stakeholders made suggestions for transparency measures that may or may not relate to development of an economic incentive but could be provided in any case to improve the effective functioning of the electricity market.

- Data should be collected that would include analysing each significant constraint, explaining why it occurred and if there is anything in the future that can be done to minimise the impact that constraint.
- Arrangements could be put in place by NEMMCO and the TNSPs to publish forecast transmission outages and the projected market impact of these outages (including a plain English description of the relevant constraint equations).
- Information should be collected on line ratings or asset ratings. ERAA/NGF propose that a measure focusing on asset rating (defined as a measure of the operating envelope for the transmission system) should be provided to NEMMCO by the TNSP. This would be established based on an internal TNSP rating standards or philosophy. This philosophy should be published initially and then reviewed and updated on an annual basis and used as input to a later benchmarking process to establish a fair and reasonable benchmark or industry best practice.
- A TNSP co-operation charter working group has been considering line and plant ratings to understand differences in methodology and, where possible, to adopt a common basis. This may result in identifying what is good electricity industry practice for determining methodologies for defining short term ratings.

Appendix C ACCC constraint cost model

C.1 Introduction

The purpose of this appendix is to provide a description of the ACCC model used to calculate total and marginal constraint costs. It describes the model and the data sources used. The model is the basis of the sample report set out in appendix D. The ACCC is willing to describe the model further to participants following specific requests.

It should be noted that NEMMCO is presently developing a refined model that provides a more accurate representation of the TCC. This model, when available, will be used to calculate the TCC measure for the actual quarterly reports.

C.2 Description

C.2.1 Assumptions

The NEM is represented in the ACCC constraint cost model as a series of five nodes and four interconnectors. The interconnectors' losses are modelled as quadratic loss functions and the parameters were chosen to ensure a best fit with actual loss information obtained from NEMMCO. The losses are shared between the regions using the proportions published by NEMMCO. The DC interconnectors, Murraylink and Directlink are modelled as price insensitive and as a simple increase in load in the exporting region and a decrease in load in the importing region.

Also the ACCC constraint cost model assumes:

- generators have no ramp rate limits
- the markets for ancillary services do not exist
- generators comply with dispatch orders, that is non-conformance constraints do not exist
- that there are no intra-regional constraints.

C.2.2 Inputs

The ACCC constraint cost model uses inputs that are all publicly available and provided by NEMMCO.

The first input is the generator bid information provided by NEMMCO. A bid consists of ten quantities the generator offers to supply at ten corresponding prices.

The ACCC constraint cost model divides each bid by the intra-regional marginal loss factor (MLF) for the corresponding connection point. The MLFs are constant and do not change. In the current version of the ACCC constraint cost model, dispatchable load is a small component and is ignored. The ACCC hopes to include dispatchable load into either its modelling in the future.

The ACCC constraint cost model also uses as inputs:

- the actual total demand at each node
- the actual interconnector flows
- the actual interconnector limits.

C.2.3 Calculations

The flow information is not used in the ACCC constraint cost model other than as a trial starting point. Depending on how the model is configured the interconnector limits can either be relaxed by a certain amount or eliminated altogether.

The model uses the bid information to create a merit order, which represents the industry supply curve at each reference node. The model uses the fact that given the total dispatch and load at any four of the five regions it is possible to determine the corresponding flows[30] Given this, it is simple to convert the quantity dispatched at each node (which determines the total energy cost) into the quantity of flow on each interconnector (which are constrained by the flow limits).

The ACCC constraint cost model seeks to find the dispatch that minimises the total energy cost. In order to calculate the regional reference prices the model relaxes demand at each node individually and then recalculates the total energy cost of dispatch. The regional reference price is defined as the rate of change of the total energy cost of dispatch in response to a small increase in demand.

C.2.4 Outputs

The output of the model is:

- the regional reference price
- total dispatch for each region
- the total energy cost for each interval.

The total constraint cost for a given time interval is estimated as the difference between the total energy cost of dispatch with all the flow limits in place (as set by NEMMCO) and the total energy cost of dispatch without any flow limits. This is summed over the relevant interval (and divided by two, in the case of half-hour intervals) for the given period.

The total constraint cost for a given interconnector is estimated as the difference between the total energy cost with all the flow limits in place and the total energy cost with the relevant interconnector's limits removed. This is summed over the relevant interval (and divided by two, in the case of half-hour intervals) for the given period.

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30 This requires finding the solution of a quadratic equation.

The marginal constraint cost is equal to the difference between the total energy cost with all the flow limits in place and the total energy cost with all the flow limits marginally[31] increased (in both directions).

The ACCC constraint cost model is written in Fortran and compiled using the F Fortran Compiler[32].

31 The ACCC constraint cost model assumes a marginal increase is 1MW.

32 Available for from www.fortran.com.

Appendix D Sample quarterly transparency report on market impacts

D.1 Introduction

This sample quarterly report is included to describe the type of information, about constraints and their market impact, which the ACCC intends to publish quarterly. It is provided for illustrative purposes only. The format of the actual quarterly reports may differ from this sample.

The sample report includes two parts about the market impact of transmission constraints. These two parts present the TCC measure (section D.2) and the MCC measure (section D.3).

Both the TCC and MCC measures shown are for the second quarter of 2004. The TCC and MCC data in this sample quarterly report was modelled by the ACCC using public information available from NEMMCO. The ACCC constraint cost model used is described in appendix C.

It should be noted that NEMMCO is currently developing a model that will provide more accurate calculations of the TCC measure. The NEMMCO model will accurately account for inter-regional and intra-regional constraints, generator ramp rate constraints, the co-optimisation of ancillary services, etc. When this model is ready the ACCC intends to use it to publish its quarterly reports. The output of this model is still being developed.

This sample report also includes a third part that illustrates the information about the nature of constraints in the NEM that the ACCC intends to publish (section D.4). This part of the quarterly report will give an overview of the nature and characteristics of constraints that occur over the quarter being reported.

It should be noted that in section D.4 the ACCC has used random numbers to illustrate the information it intends to publish.

D.2 Total constraint cost

The economic benefit of the TNSP's action that increases the capacity of the network can be measured by the change in the total energy cost of dispatch due to that action. That is the change in the total cost of dispatching sufficient generation to meet demand before and after the action by the TNSP.

Hence the TCC for a given network configuration can be defined as the difference in the actual total energy cost of dispatch for that network and the estimated total energy cost of dispatch for a network assuming it had no binding constraints.

Therefore the TCC is defined as the difference between the total energy cost of dispatch between the normal case and the unconstrained case, where:

- the total energy cost is the area under the offer curve; or bid stack; up to the last unit of electricity dispatched
- the normal case includes all inter-regional flow limits as given by NEMDE for that time interval
- the unconstrained case relaxes all inter-regional flow limits (it should be noted that in NEMMCO's model all transmission constraints would be relaxed).

During the first quarter of 2003 the TCC in the NEM was $1.724 million, compared with $8.082 million in the previous quarter. The TCC over the previous four quarters was $14.853 million (see table D.1).

Table D.1 – Total constraint costs

Total constraint cost ($/MWh)	Current quarter	Last 2 quarters		Last 4 quarters
	Q1/03	Q4/02	Q3/02	Q2/02–Q1/03
SA–VIC	436,959	216,588	75,283	1,062,468
VIC–SNOWY	362,364	1,443,778	509,983	2,435,719
SNOWY–NSW	525,260	3,094,581	0	4,658,036
NSW–QLD	680,213	3,784,324	380,144	7,492,063
Total NEM[33]	1,724,054	8,081,682	945,502	14,852,792

Figure D.1 shows the TCC by quarter, since the third quarter in 2000.

33 The TCC for the NEM is not equal to the sum of the TCC of each interconnector.

Figure D.1 – Total constraint cost (Q3/00 – Q2/03)

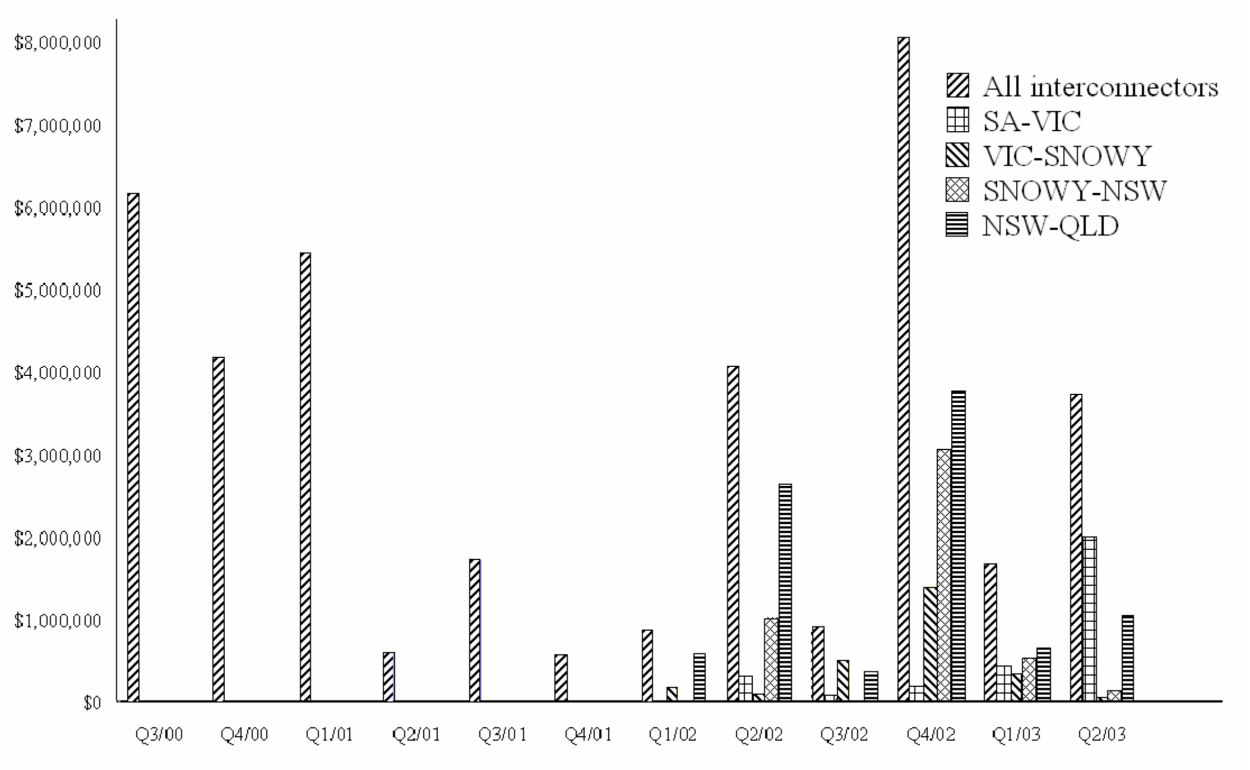
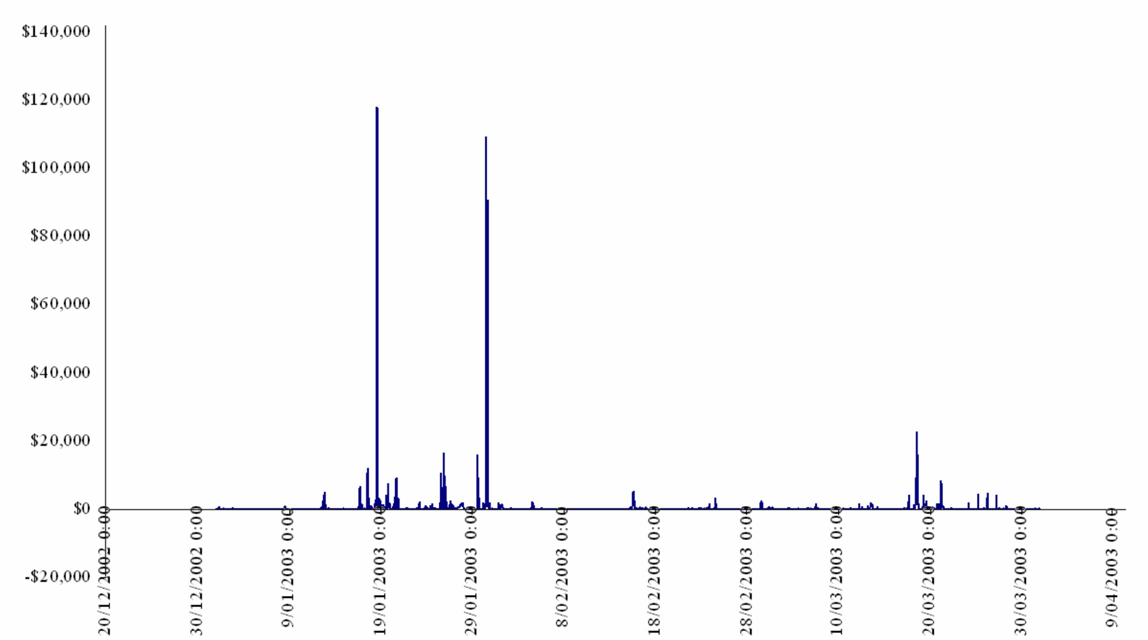


Figure D.2 shows the TCC for each half-hour in the first quarter of 2003.

Figure D.2 – Total constraint cost by half hour (Q1/03)



The half hour periods with the highest TCC are shown in table D.2. These 20 half-hour periods account for 45% of the TCC during the quarter.

Table D.2 – Highest total constraint cost occurrences (Q1/03)

Date	Time	Total constraint cost ($/MWh)				
		VIC–SNOWY	SNOWY–NSW	NSW–QLD	SA–VIC	Total NEM[34]
18 January 2003	1:30 pm – 2:00 pm	228	115,837	98,474	0	117,923
30 January 2003	11:30 am – 12:00 pm	0	108,495	104,578	0	109,240
30 January 2003	4:00 pm – 4:30 pm	0	81,518	57,147	0	90,691
30 January 2003	4:30 pm – 5:00 pm	1,351	76,211	49,588	0	78,729
18 January 2003	2:30 pm – 3:00 pm	620	60,688	36,717	0	61,802
30 January 2003	12:30 pm – 1:00 pm	6,797	29,212	4,591	0	41,744
30 January 2003	5:00 pm – 5:30 pm	2,528	26,066	0	0	29,530
30 January 2003	2:30 pm – 3:00 pm	6,674	211	0	0	28,692
30 January 2003	1:30 pm – 2:00 pm	13,087	0	0	0	24,532
18 March 2003	3:00 pm – 3:30 pm	18,614	0	965	0	22,690
30 January 2003	3:30 pm – 4:00 pm	6,112	12,742	0	0	22,544
30 January 2003	1:00 pm – 1:30 pm	9,410	5,749	0	0	18,620
25 January 2003	9:30 pm – 10:00 pm	0	0	0	16,432	16,432
18 March 2003	4:00 pm – 4:30 pm	11,008	0	1,419	0	16,055
29 January 2003	3:00 pm – 3:30 pm	0	0	16,021	0	16,021
30 January 2003	3:00 pm – 3:30 pm	5,776	7,214	0	0	15,765
29 January 2003	2:00 pm – 2:30 pm	0	0	14,954	0	14,954
30 January 2003	2:00 pm – 2:30 pm	6,983	0	0	0	14,421
17 January 2003	3:30 pm – 4:00 pm	0	1,318	12,098	0	12,098
18 March 2003	4:30 pm – 5:00 pm	7,521	0	1,124	0	11,050

Some of the half hour periods shown in table D.2 are consecutive, which indicates that abnormal events may have occurred over the particular consecutive period that can help to explain the existence of the high cost of constraints. These consecutive half hour periods of high TCC are described as episodes and are shown in table D.3.

34 The TCC for the NEM is not equal to the sum of the TCC of each interconnector.

Table D.3 – Five highest total constraint cost episodes

Date	Time	Total constraint cost ($/MWh)
18 January 2003	1:30 pm – 2:30 pm	180,296
30 January 2003	11:30 am – 5:00 pm	475,195
18 March 2003	3:00 pm – 4:00 pm	47,259
25 January 2003	9:30 pm – 10:00 pm	16,431
29 January 2003	2:00 pm – 3:00 pm	37236

The five episodes listed in table D.3 are used as an indicator of areas that need further investigation. In the actual reporting process the ACCC will likely report the 40 to 50 half hours periods with the highest TCC. This will enable the ACCC to identify about ten episodes that require further investigation.

As part of this transparency reporting the ACCC does not intend to comment in hindsight about what action, if any, TNSPs should or should not have taken. Rather publishing the quarterly reports is intended to provide the starting point for the ACCC, the market and TNSPs to get a better understanding of whether TNSPs, given the right incentives, could efficiently reduce the market impact of constraints.

Therefore sections D.2.1 to D.2.5 provide a brief description of what events occurred during the five episodes shown in table D.3. These events may have been contributing factors to the high constraint cost or may have been just coincidences.

D.2.1 Events on 18 January 2003, 1:30 – 2:30 pm

NECA reported the following about events that occurred on this date.

- ‘Temperatures in Sydney reached a maximum of 39 degrees, 4 degrees higher than that forecast the day before. Demand outstripped the forecasts produced 4 hours prior to dispatch by up to 1,200MW reaching the highest ever Saturday summer demand.’[35].

- ‘Exports north from Victoria were maintained at the limit throughout the day. At 3.45pm Southern Hydro reduced availability at McKay by 120MW to zero. The rebid reason given was .DAMS CONTROL’[36].

- ‘Discretionary constraints on QNI restricted exports from Queensland to 475 MW and resulted in spot prices in Queensland separating from New South Wales. These restrictions were to manage network loading in northern New South Wales’[37].

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35 NECA, Weekly report, 12 January – 18 January, page 8.

36 NECA, Weekly report, 12 January – 18 January, page 11.

37 NECA, Weekly report, 12 January – 18 January, page 6.

Exports from Victoria to Snowy were maintained at the limit throughout the day and flows south on Queensland to New South Wales interconnector (QNI) were binding during the afternoon. Flows from Snowy to New South Wales, that were limited to 2800MW earlier in the day, reduced to 1613MW at 1:30, increased to 2064MW at 2 pm and then reduced to 1767MW at 2:30 pm. The spot price reached $3435.83 in New South Wales at 1:30 pm and $2670.32 at 2:30 pm.

Table D.4 – Binding constraints 18 January 2003, 1:00 – 2:35 pm

Constraint ID	Constraint description	Sum of marginal value ($/MWh)
H>H–64__04	Out= LT–UT(64); raise UT/LT Gen to avoid MS–UT OL on MS–LT trip	19
I_DDMS0300	Limit DDTS–Murray (67+68) lines to 300MW from Vic to Snowy	174
I_DDMS0350	Limit DDTS–Murray (67+68) lines to 350MW from Vic to Snowy	57
I>D1200–HN	Discretionary Snowy to NSW transfer upper limit of 1200 MW	2,163
I>D1300–HN	Discretionary Snowy to NSW transfer upper limit of 1300 MW	1,576
I>D1500–HN	Discretionary Snowy to NSW transfer upper limit of 1500 MW	398
Q>0856	Sys Intact Q–N transfer(757+758)<=170MW(select) at Mudgeeraba	3,867
Q>N–NIL_DF	Out= NIL,limit Q–>N not to OL 965 on 9W3 trip,both R&S on CH;Fbk	62,915
QN_475	Qld to NSW on QNI upper transfer limit of 475 MW	1,891

D.2.2 Events on 30 January 2003, 11:30 am – 5:00 pm

Flows between Snowy and New South Wales were at or very near their limit throughout this period. Flows between Victoria and Snowy were constrained at their limit from around 1:30 pm for the rest of the day. Flows on QNI were at their limit except for a period from 1:00 to 3:00 pm when they were reduced. Prices reached $5113.60 in NSW at 12:30 pm, and were about $2000 from 3:30 to 5:00 pm.

NECA reported the following about events that occurred on this date.

- 'Constraints to manage network limits in northern New South Wales restricted exports from Queensland to around 580MW for most of the day'.[38]
- 'Conditions [in NSW] at the time saw demand relatively close to forecast, peaking at a record level of almost 12,350MW at 3.30pm. Network constraints in New South Wales and within Snowy and on inter-regional transfers affected market outcomes.'[39]
- 'Conditions [in VIC] at the time saw actual demand over 600MW higher than forecast. Flows into New South Wales were constrained at levels between

[38] NECA, Weekly report 26 January – 1 February, page 8.

[39] NECA, Weekly report 26 January – 1 February, page 10.

600MW and 900MW primarily as a result of a planned network outage. At around 11:30am Yallourn Energy rebid 105MW from prices less than $20/MWh to greater than $9,000/MWh, close to dispatch. The rebid reason given was .11:34 SN–NSW LINK CONSTRAINT – BAND SHIFT UP.'[40]

Table D.5 – Binding constraints 30 January 2003, 11:00 am – 5:30 pm

Constraint ID	Constraint description	Sum of marginal value ($/MWh)
H>H–64__04	Out= LT–UT(64); raise UT/LT Gen to avoid MS–UT OL on MS–LT trip	200,000
H>H–64__05	Out= LT–UT(64); raise UT/LT Gen to avoid MS–LT OL on MS–UT trip	245,363
H>N–02__01	Out= UT – Yass (02), limit NSW import to avoid 01 OL on 07 trip	33,333
H>N–NIL__1	Out= Nil, limit H–>N flow to avoid UT–Canberra(01) OL on 07 trip	39,190
H>N–NIL01F	Out= NIL; avoid 01 OL on NIL trip by limiting NSW Import; FeedBk	491
H>N–SM2__B	Out= LT–UT (SM2),limit NSW Imp. from S to avoid 07 OL on 03 trip	108
I_DDMS0150	Limit DDTS–Murray (67+68) lines to 150MW from Vic to Snowy	524
N>N–NIL_07	NSW internal, Outage of NIL, load on 07 on trip of 03	2,630
N>N–NIL_08	NSW internal, Outage of NIL, load on 07 on trip of 01	22,263
N>N–NIL_28	NSW internal, Outage of NIL, load on 8 on trip of 16	87,437
Q^NIL_FNQ3	Qld syst.Normal; volt.collapse FNQ Lmt(cont Chal–Cairns)	33,333
Q^NIL_FNQ4	Qld syst.Normal; volt.collapse FNQ Lmt(cont Ross–Chal)	33,333
Q>0856	Sys Intact Q–N transfer(757+758)<=170MW(select) at Mudgeeraba	11,683
Q>0872	GCuvLmt=447.2+f(SB,Wiv–units,Blk,DL;BlkVadj;H4mvar)Sys Intact	76
Q>N–NIL_DF	Out= NIL, limit QNI+DL (Q–>N) to avoid 965 OL on 9W3 trip; Fbk	359,502
QNS_0500	Qld to NSW summated QNI+DL upper transfer limit of 500 MW	18,691
QNS_0575	Qld to NSW summated QNI+DL upper transfer limit of 575 MW	959
S>VML_1NIL	Out=Nil,SA–V_ML,0/L Lmt for NWB–RB#1/MH–RB2;trip on MH–RB/NW–RB	2
VH>V1EPTT	V–SN,EP–TT Out,Eqn1.1–70, F2 TX RTG,Radial	1,575
VH>V3NIL	V–SN,SYS NORM incl ROTS Tfr, F2 TX RTG, RADIAL	361

D.2.3 Events on 18 March 2003, 3:00 – 4:00 pm

Demand on this day was at a three-week high in Victoria and month high in South Australia.[41] Flows south from Snowy were constrained at their limit for virtually all the afternoon. QNI was also binding in the south direction all day. Prices reached $418.95 in South Australia at 2:30 pm and $382.37 at the same time in Victoria.

[40] NECA, Weekly report 26 January – 1 February, page 13.

[41] NECA, Weekly report, 16 March – 22 March, page 8.

Table D.6 – Binding constraints 18 March 2003, 2:30 – 4:00 pm

Constraint ID	Constraint description	Sum of marginal value ($/MWh)
H>V_NIL1A	SN–V & V–S–MNSP1,Out=Nil, DD–MS load – DD–MS trip,15 min rating	247
I>D0750–QN	QLD–NSW QNI Discretionary transfer upper limit of 750 MW	11
Q>0856	Sys Intact Q–N transfer(757+758)<=170MW(select) at Mudgeeraba	29

D.2.4 Events on 25 January 2003, 9:30 pm

High demand conditions over Victoria and South Australia saw prices across the NEM rise to about $200 to $300 throughout the middle of the afternoon. However after prices elsewhere in the NEM declined to around $30 to $40 in the evening and the price in South Australia spiked again to $236.33 at 9:30 pm.

NECA reported the following about events that occurred on this date.

- 'Conditions [in NSW] at the time saw demand close 400MW higher than forecast 4 hours prior to dispatch. Exports from Queensland across QNI and Directlink were constrained over much of the afternoon to around 850MW.'[42].
- 'Conditions [in VIC] at the time saw actual demand up to 200MW lower than forecast, but at record levels for a Saturday in Victoria and South Australia. Exports to South Australia were operating at the limit of 500MW, whilst imports from Snowy were above 1,300MW for much of the day but below the limit. Southern Hydro reduced availability across most of its portfolio by a total of 170MW for the trading interval ending 3.00pm. The reasons given were .LINE OUTAGE DUE TO BUSHFIRES. and .BUSHFIRE FIGHTING AND CONTROL.'.[43]

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42 NECA, Weekly report, 19 January – 25 January, page 8.

43 NECA, Weekly report, 19 January – 25 January, page 11.

Table D.7 – Binding constraints 25 January 2003, 8:00 – 10:30 pm

Constraint ID	Constraint description	Sum of marginal value ($/MWh)
I>D0750–QN	QLD–NSW QNI Discretionary transfer upper limit of 750 MW	2
I>VS–500	VIC–SA Export Limit Nil Outage	55
Q>0856	Sys Intact Q–N transfer(757+758)<=170MW(select) at Mudgeeraba	5
V^SML_NIL2	Out=Nil, V–SA on MLNK, Vstab for loss of X5, NSW runback O/S	1
V^SML_NIL3	Out=Nil, V–SA on MLNK, Vstab for loss of BETS–KGTS	1
V>S_CGRB	Vic–SA Thermal(O/L) transfer limit(Cont.CherryG–MtBarker SVC)	138
V>SML_1NIL	Out=Nil,V–SA_ML,0/L Lmt NWB–RB1/MH–RB2;tripOn MH–RB/NW–RB/MH–RB1	0
VSS_500	Vic to SA on Vic–SA + ML upper transfer limit of 500 MW	46

D.2.5 Events on 29 January 2003, 3:00 – 4:00 pm

A new Victoria record demand was reached (8035 MW) at 4 pm on this day. A new NEM-wide record demand of 28480 MW was reached at the same time. Prices peaked at $304.10 in Victoria and $301.87 in South Australia at 4:00 pm.

Table D.8 – Binding constraints 29 January 2003, 2:30 – 4:30 pm

Constraint ID	Constraint description	Sum of marginal value ($/MWh)
Q>0856	Sys Intact Q–N transfer(757+758)<=170MW(select) at Mudgeeraba	52
Q>0872	GCuvLmt=447.2+f(SB,Wiv–units,Blk,DL;BlkVadj;H4mvar)Sys Intact	267
QN_500	Qld to NSW on QNI upper transfer limit of 500 MW	248
S>VML_1NIL	Out=Nil,V–SA_ML,0/L Lmt NWB–RB1/MH–RB2;tripOn MH–RB/NW–RB/MH–RB1	53

D.3 Marginal constraint cost

In principle a marginal cost of a good is the change in cost of that good resulting from a marginal change in the output of that good. To simplify, for the MCC measure, a marginal change in output is assumed to be a reduction in the transmission constraint of 1MW.

The calculation of the MCC measure is similar to that of the TCC measure, again the change in the total energy cost is used as the estimate. The MCC is defined as the difference between the total energy cost for the normal case and the case where all inter-regional transfer flow capabilities are increased by 1 MW (in both directions).

This sample report only considers the MCC of inter-regional constraints. This is a limit of the ACCC constraint cost model. However the ACCC will consider the usefulness the NEMDE marginal value output as a better estimate of this measure.

During the first quarter of 2003 the MCC in the NEM was $21,888, compared with $88,206 in the previous quarter. The MCC was $156,607 for the previous four quarters (table D.9).

Table D.9 – Marginal constraint cost

Marginal constraint cost ($/MWh)	Current quarter	Last 2 quarters		Last 4 quarters
	Q2/03	Q1/03	Q4/02	Q2/02–Q1/03
Total NEM	21,888	88,206	13,865	156,607

Figure D.3 – Marginal constraint cost (Q3/00 – Q2/03)

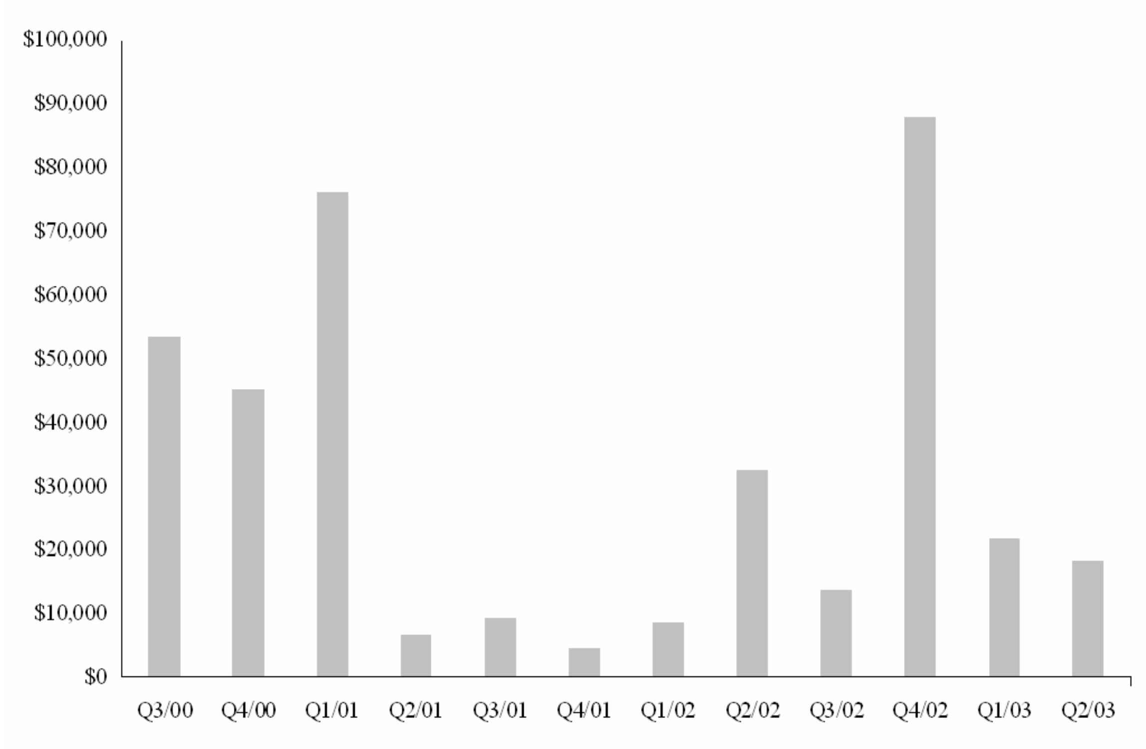
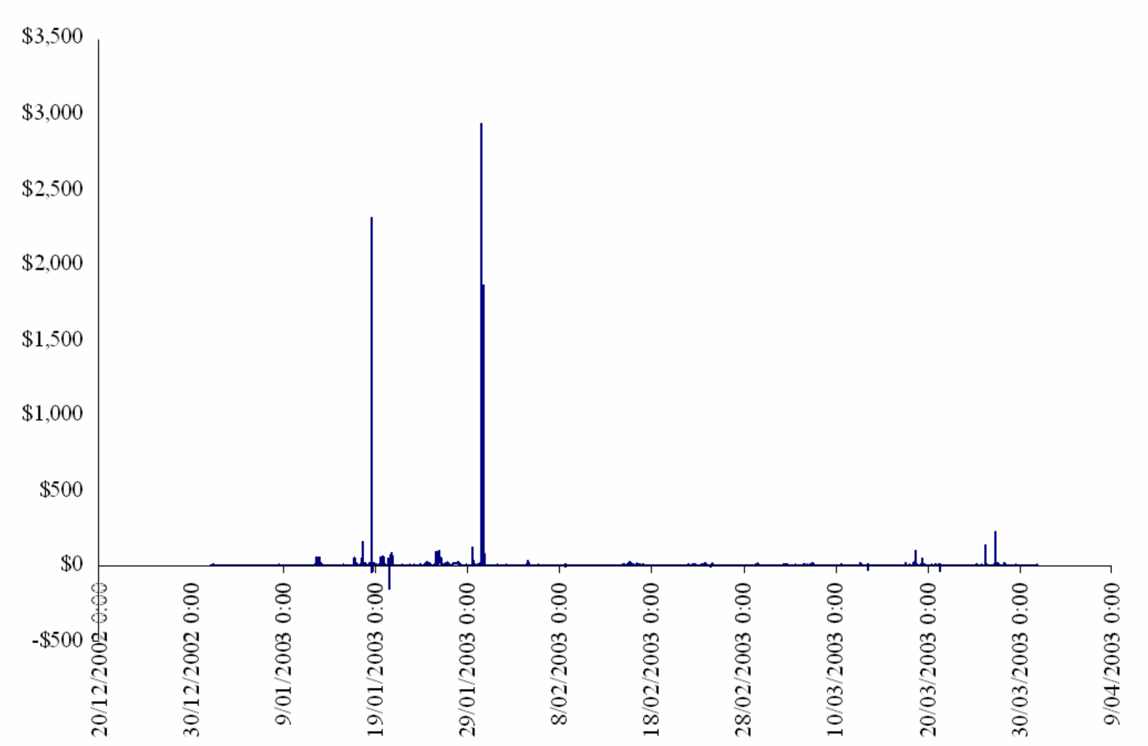


Figure D.3 shows the MCC by quarter between the third quarter in 2000 and the second quarter in 2003 and figure D.4 shows the MCC for the every half hour period in the first quarter of 2003.

Figure D.4 – Marginal constraint costs (Q1/03)



The periods with the highest MCC are shown in table D.10. These 20 half-hour periods account for 70% of the MCC during the period.

Table D.10 – Highest marginal constraint cost occurrences (Q1/03)

Date/time	Time	Marginal constraint cost ($/MWh)
30 January 2003	11:30 am – 12:00 pm	2,935
18 January 2003	1:30 pm – 2:00 pm	2,308
18 January 2003	2:30 pm – 3:00 pm	2,036
30 January 2003	4:30 pm – 5:00 pm	1,865
30 January 2003	12:30 pm – 1:00 pm	763
30 January 2003	5:00 pm – 5:30 pm	258
27 March 2003	7:00 am – 7:30 am	230
17 January 2003	3:30 pm – 4:00 pm	158
26 March 2003	7:00 am – 7:30 am	140
29 January 2003	2:00 pm – 2:30 pm	121
18 March 2003	3:00 pm – 3:30 pm	103
30 January 2003	1:30 pm – 2:00 pm	102
25 January 2003	9:30 pm – 10:00 pm	101
30 January 2003	2:30 pm – 3:00 pm	101
18 March 2003	4:00 pm – 4:30 pm	101
25 January 2003	9:00 pm – 9:30 pm	101
30 January 2003	3:30 pm – 4:00 pm	100
30 January 2003	2:00 pm – 2:30 pm	100
30 January 2003	3:00 pm – 3:30 pm	97
30 January 2003	1:00 pm – 1:30 pm	93
25 January 2003	1:30 pm – 2:00 pm	91

Table D.11 – Highest marginal constraint cost episodes

Date	Time	Marginal constraint cost ($/MWh)
30 January 2003	11:30 am – 6:00 pm	6,414
18 January 2003	1:30 pm – 3:30 pm	4,344
27 March 2003	7:00 am – 8:00 am	230
18 March 2003	3:00 pm – 5:00 pm	204
25 January 2003	9:00 pm – 10:30 pm	202
17 January 2003	3:30 pm – 4:30 pm	158
26 March 2003	7:00 am – 8:00 am	140
29 January 2003	2:00 pm – 3:00 pm	121
25 January 2003	1:30 pm – 2:30 pm	91

Table D.3 and table D.11 show the highest TCC and MCC episodes. In the data sample used the TCC and MCC measures have identified almost the same episodes. Hence the ACCC has not, for the purposes of this sample report, commented on the episodes that are identified by the MCC measure in table D.11. However in the actual quarterly reports the it would.

D.4 The nature of constraints

This part of the quarterly report is intended to provide an overview of the constraints that occurred in the quarter being reported. Like the other sections of the quarterly report this part is likely to evolve over time to capture any information about constraints that the ACCC considers to be useful and relevant.

Unlike the TCC and MCC measure this section of the report is not intended to quantify the market impact of constraints.

This section of the report is intended to be based on inputs provided by TNSPs and possibly NEMMCO. In publishing information provided by TNSPs the ACCC is mindful of its information disclosure responsibilities under the code.

It should be noted that figures D.5 – D.10 are based on random data and are included for illustrative purposes.

Figure D.5 provides an overview of the constraints that have occurred over the reported quarter and the previous year. It reports the number of constraints that occurred in each region regardless of their cause. This will allow an easy comparison of constraints over time and across regions.

Time series comparisons may be affected by seasonal influences and cross section comparisons could be influenced by location specific issues. However the use of such comparisons as a learning tool will be invaluable.

Figure D.5 – Intra-regional constraints

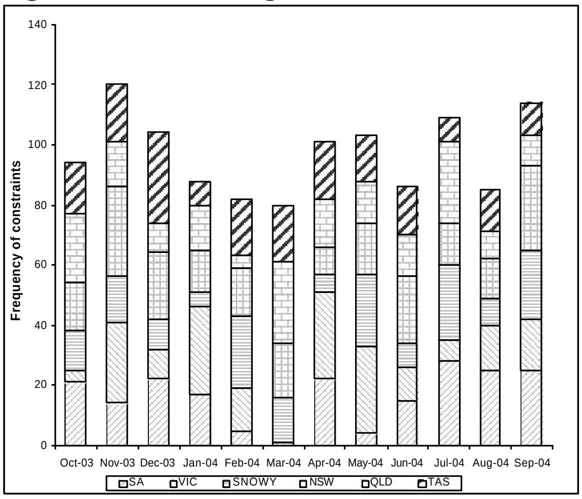


Figure D.6 – Inter-regional constraints

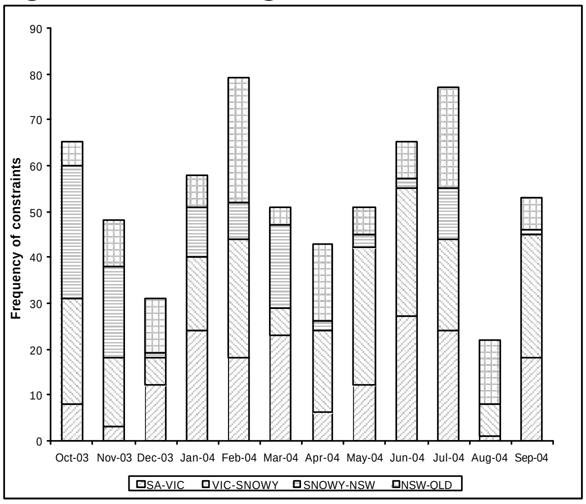


Figure D.6 is similar to figure D.5, however it presents the same information for inter-regional constraints.

Figure D.7 is provided to give an overview of the extent that constraints on the transmission network are associated with transmission outages. Although this does not consider the market impact of the constraints, it will be a useful learning tool.

The sample graph in figure D.7 only illustrates inter-regional constraints, however the ACCC intends to publish this information about constraints in each region and for interconnectors.

Figure D.7 – System normal and outage constraints

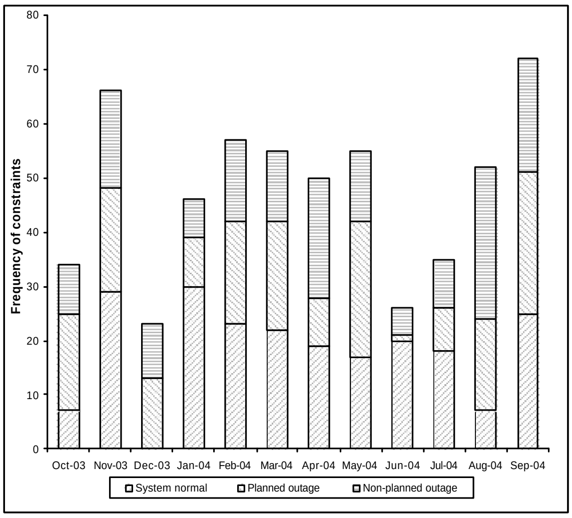


Figure D.8 – Constraints at different load levels

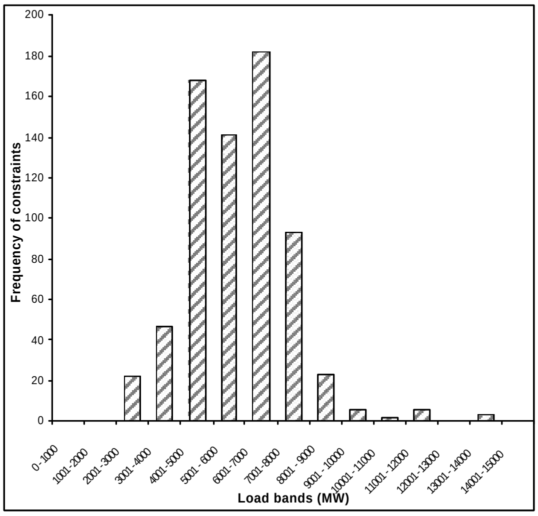


Figure D.9 – Stability, voltage and thermal constraints

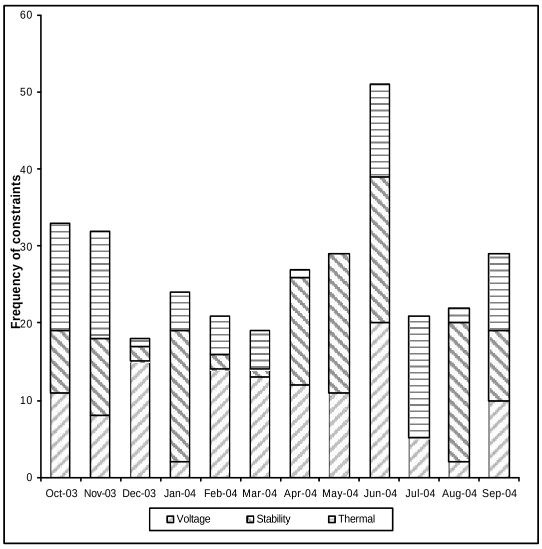
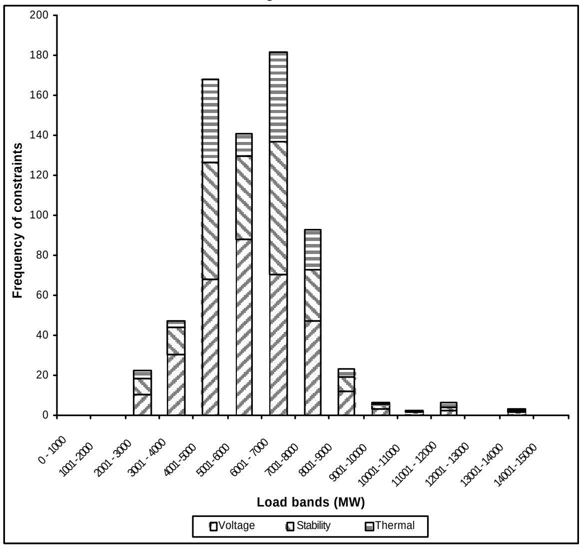


Figure D.10 – Stability, voltage and thermal constraints by load level



It is important to the market that constraints are minimised at times when the supply of electricity is valued the most. The ACCC considers that system demand can be used as an indicator of times when the supply of electricity is most valued by the market. Hence figure D.8 is included to show the frequency of constraints occurring when the region is experiencing different load levels.

Figure D.9 and D.10 provide similar constraint information as the previous figures. However they classify constraints as stability, voltage or thermal constraints. Again this information should provide a useful learning tool to understand the patterns and characteristics of constraints.

The ACCC intends to publish this information about constraints for each region and for interconnectors.

Supplementary Discussion Paper

Review of the Draft Statement of Principles for the Regulation of Transmission Revenues

Capital Expenditure Framework

10 March 2004

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1. Introduction

Since 1 July 1999, the Australian Competition and Consumer Commission (Commission) has assumed responsibility for the regulation of transmission revenues in the National Electricity Market (NEM) on a progressive basis. It has undertaken first round revenue assessments of each of the transmission network service providers (TNSPs) in the NEM. In assessing the revenue requirements for the TNSPs in New South Wales, TransGrid and Energy Australia, the Commission is conducting its first revenue resets.

The National Electricity Code (Code) sets out the general principles and objectives of the transmission revenue regulatory regime to be applied by the Commission. In part, the Code establishes that the transmission revenue regulatory regime must achieve outcomes which are efficient and cost effective; foster efficient investment; and are reasonably accountable, transparent and consistent over time. Similarly, in its December 2003 statement, the Ministerial Council on Energy (MCE) adopted the following principle to underpin transmission policy in the NEM:

> *"Transmission investment decisions should be timely, transparent, predictable and nationally consistent, at the lowest sustainable cost."*

The regulation of capital expenditure (capex) plays a critical role in determining whether these objectives are met, as capex is one of the biggest drivers of a TNSP's revenue. The current regulatory framework puts the Commission as regulator in the position of attempting to assess the prudency of the investment program after the investments have been made. In undertaking this assessment, the Commission will take into account regulatory test assessments undertaken by TNSPs. The regulatory test is the prudency test set out in the Code to assess the economic efficiency of investment decisions.

In the recent Discussion Paper *Review of the Draft Statement of Principles for the Regulation of Transmission Revenues* (Regulatory Principles Discussion Paper) the Commission proposed adopting an approach for assessing a TNSP's capex that relied more heavily on the regulatory test. Indeed, the Commission noted that revenue caps will accommodate new investment if proposed capex programs satisfy the regulatory test.

The Commission's review of the regulatory test, recent assessment of the Murraylink conversion application, and current reviews of the revenue caps of TransGrid and EnergyAustralia have led it to question whether the objectives and principles outlined above can be best achieved under the NEM's current transmission investment framework.

This paper explores a different approach to transmission investment in the NEM, one that relies more on assessing a firm cap on TNSP investment - that provides incentives for economic efficiency and reduces regulatory uncertainty. As this potentially entails a change in approach to that outlined in the Regulatory Principles Discussion Paper, the Commission believes that it is appropriate to release this Supplementary Discussion Paper.

The paper is structured as follows. The following section describes how TNSP investment is regulated now and traces the history of these arrangements, while section 3 discusses the issues that have arisen under the current arrangements. Section 4 proposes potential reform to the regulation of transmission investment in the NEM, with the introduction of a firm ex-ante cap on capital expenditure. Section 5 discusses circumstances where it may be appropriate to exclude certain investment from the firm ex-ante cap, while section 6 discusses circumstances where it may be appropriate to "re-open" the ex-ante cap. Section 7 outlines implications of the proposed arrangements for the operation of the regulatory test, while section 8 outlines the Commission's process for considering these capital expenditure framework issues.

This Supplementary Discussion Paper should be read in conjunction with the Draft Decision on the regulatory test, which is being released at the same time as this paper.

2. The history of the regulation of transmission investment in the NEM

2.1 Introduction

This section provides background information on how TNSP investment is regulated in the NEM. It draws out the key features of the current framework for the regulation of transmission investment, by discussing the history of these arrangements. It focuses, in turn, on the *Draft Statement of Principles for the Regulation of Transmission Revenues* (Draft Regulatory Principles), the Regulatory Test and the Network and Distributed Resources Code changes.

2.2 The ACCC's regulatory obligations under the Code

Clause 6.2.2 of the Code sets out the objectives of the transmission revenue regulatory regime to be administered by the ACCC. The clause does not prescribe the details of the mechanism that the ACCC should implement, but rather defines the outcomes that the ACCC must seek to achieve. These include:

- an "incentive-based" regulatory regime which provides "an equitable allocation" between service providers and their customers, of the efficiency gains "reasonably expected" by the ACCC;

- "prospectively" providing a revenue stream which includes a "fair and reasonable rate of return" on "efficient investment"; and

- creating "an environment which fosters an efficient level of investment … ".

2.3 Draft Regulatory Principles

The May 1999 Draft Regulatory Principles was a first attempt from the Commission to outline the regulatory framework that it would adopt to achieve these outcomes. In the Draft Regulatory Principles, the Commission noted that there is a dilemma as to how actual and forecast capex should be treated at the start of the regulatory period given knowledge of forecast and actual capex from the previous regulatory period and forecast capex for the next regulatory period.

Accordingly, the Commission noted that it would:

- At the start of the regulatory period roll into the asset base projected capex for the regulatory period when it is scheduled to become operational.

- In relation to capex at the start of the next regulatory period for the previous regulatory period, include in the asset base only actual capital expenditure since the previous review.[1]

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[1] ACCC, *Draft Statement of Principles for the Regulation of Transmission Revenues* (Draft Regulatory Principles), p55.

At the regulatory reset the Commission noted that it would consider reviewing the prudency of large capital expenditures and may seek assurances that the TNSP has complied with the requirements of clause 5.6 of the Code.[2] Such a process necessitates a project-specific assessment of capital expenditure.

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

Therefore, there was a need to put in place a mechanism to try to ensure that the capex spent was efficient. In the draft statement, the Commission noted that in gas, new facilities investment needed to pass a prudent investment test to be included in the capital base. The Commission proposed that a similar test be implemented for electricity transmission assets.

Statement S5.1 notes that the TNSP's asset base can be increased to recognise capital expenditure. In part it notes that the asset base can be increased by actual cost provided that "the amount does not exceed the amount that would be invested by a prudent TNSP acting efficiently in accordance with good industry practice and to achieve the lowest sustainable cost of delivering services." Statement S5.1 also dealt with the optimisation issue by noting that if the actual capital cost incurred by the TNSP was deemed excessive by the Commission then only the prudent amount of expenditure will be added to the regulatory asset base. Once again, this requires a project-specific assessment of capital expenditure.

2.4 Regulatory Test

While recognising the importance of prudent investment, the Draft Regulatory Principles did not specify the prudency test that was to apply in any great detail. It was not until the introduction of the regulatory test in 1999 that a prudency test became part of the regulatory framework.

There are two limbs to the regulatory test. A transmission augmentation is deemed to have satisfied the test if it maximises the net present value of the market benefits, having regard to a number of alternative projects, timings and market development scenarios. Augmentations required due to an inability of TNSPs to meet network reliability requirements satisfy the regulatory test if they minimise the net present cost of meeting the standard.

Initially, these regulatory test outcomes were linked to a TNSP's capex allowance. From the time of its promulgation at the end of 1999 to March 2002, the Code provided that any investment that satisfied the regulatory test would be rolled-in to the regulatory asset base. During this time, the National Electricity Market Management Company (NEMMCO) was obliged under the Code to conduct the regulatory test for inter-regional investments, and in so doing to establish an Inter-regional Planning Committee (IRPC) to advise it accordingly. NEMMCO's decisions could be reviewed by the National Electricity Tribunal. This appeal route was used when NEMMCO's

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[2] The Commission notes that since the time of the writing of the Draft Regulatory Principles, clause 5.6 of the Code has been amended.

decision that TransGrid's SNI, a proposed interconnector joining South Australia and New South Wales, satisfied the regulatory test was appealed to the National Electricity Tribunal.

In developing intra-regional augmentations, TNSPs were required to satisfy the regulatory test. They were entitled to include in their Regulatory Asset Base the capex determined in their application of the regulatory test.

2.5 Network and Distributed Resources Code Changes

The time delays potentially involved in considering a network augmentation proposal under the Code were demonstrated by the SNI process. NEMMCO determined in December 2001 that SNI passed the regulatory test. Subsequently, this was appealed to the National Electricity Tribunal and the Victorian Supreme Court, with a further hearing pending before the Victorian Court of Appeals. These concerns prompted calls to streamline the process for approving network augmentation.

From March 2002, with the Network and Distributed Resources Code change package, substantial changes to the application of the regulatory test took effect. The role of conducting regulatory test assessments for inter-regional projects was removed from the IRPC, which meant that there was no need to separately distinguish inter and intra regional assets.[3] These Code changes introduced a distinction between small assets (less than \$10 million) and large assets (greater than \$10 million).

Importantly, TNSPs were given the responsibility of applying the regulatory test to inter-regional augmentations. Given that TNSPs were to apply the regulatory test, the Network and Distributed Resources Code change process also overhauled dispute resolution processes. The dispute resolution process developed consists of appeal firstly to a Dispute Resolution Panel (on any matter except whether the investment passes the regulatory test) and then to the Commission (on whether the investment passes the regulatory test) although this latter step only applies for non-reliability augmentations. There is a truncated consultation process for small network assets and interested parties, which does not involve these appeal mechanisms.

The Network and Distributed Resources Code changes also brought important changes in terms of the relationship between the regulatory test and TNSP expenditure. The Code no longer expressly requires the Commission to include an asset in the determination of a revenue cap, even if the project satisfied the regulatory test at the time the test was applied was applied to the project. As such there is now no formal link between these regulatory test outcomes and the TNSP's capex allowance.

[3] While this may be the case, the distinction between inter-and intra-regional projects remains as TNSPs have statutory obligations which only apply intra-regionally. This issue is explored in more detail in Section 5.2 of this Supplementary Discussion Paper.

3. The existing capital expenditure framework

3.1 Introduction

The Commission is reviewing the operation of this transmission investment framework as part of its process to finalise the regulatory principles. This section will discuss issues surrounding this framework. This section will first discuss whether the current approach to the treatment of capital expenditure and the proposed methodology for asset valuation are consistent. Following this, issues associated with the operation of the regulatory test will be outlined. Finally, the potential intrusiveness of the current approach will be discussed.

3.2 Investment incentives

In the Regulatory Principles Discussion Paper, the Commission noted that an approach to asset valuation that relied on periodic revaluation of assets created a high level of uncertainty for TNSPs. The ability of the regulator to optimise assets meant that the TNSP might not be compensated for all of its capital expenditure. Therefore, in the Discussion Paper, in order to provide certainty for the TNSPs, the Commission proposed an approach to asset valuation where the jurisdictional asset base would be locked in.

The Discussion Paper did not, however, explicitly address the process for reviewing capital expenditure. Under the current regulatory framework, a capex allowance is one of the fundamental “building blocks” used to determine the revenue cap at the commencement of the regulatory period. At the end of the regulatory period, there is an ex-post assessment of actual capital investment against the regulatory test.

The Commission’s current processes of assessing the revenue requirements of TransGrid and EnergyAustralia have highlighted problems with an ex-post framework. Notably, in circumstances where actual capital investment exceeds the capital expenditure allowance an ex-post framework increases the potential for optimisation. These optimisation powers are inconsistent with an aim of creating greater certainty. As noted above, improving certainty has been an important driver on the Commission’s thinking on other regulatory issues, such as asset valuation.

While an objective of the regulatory framework is to provide greater certainty for investors, it is important that this is combined with appropriate “checks and balances.” The current framework attempts to address this goal through the regulatory test. Therefore, if the project passes the regulatory test, the TNSP has a high degree of confidence that the project will not be optimised.

However, the TransGrid and EnergyAustralia processes highlight that this is less than straight forward. The discussion of the regulatory test issues below demonstrates some potential problems with the regulatory test. Therefore, the Commission believes that there may be a need to move to an ex-ante assessment rather than an ex-post assessment of new investment if an environment of greater regulatory certainty is to be achieved.

3.3 Concerns with the operation of the regulatory test

This discussion above suggests that the regulatory test plays a key role within this capex framework. The process of applying the regulatory test and regulatory test outcomes are designed to give certainty to the TNSPs that their capex programs will not be subject to ex-post optimisation.

However, to generate this certainty it would appear that the regulatory test and its application must be unambiguous, transparent and objective. It is debatable whether this is the case. The sensitivity of regulatory test modelling to input assumptions involves a high degree of judgement, as does the classification of projects as reliability or non-reliability augmentations. This sensitivity of regulatory test modelling to input assumptions means that it is difficult to envisage the regulatory test providing unequivocal results. Therefore, it is unlikely to provide "black and white" certainty for investors.

Further, the regulatory framework relies on interested parties effectively evaluating a TNSP's application of the regulatory test. It is questionable whether interested parties have the skills, expertise or resources to make a sufficiently informed assessment of whether a TNSP has applied the test thoroughly and impartially. To accurately assess a TNSP's application of the regulatory test, an interested party would need to undertake detailed costings of various alternative projects. This is a highly specialised task which requires a significant commitment of resources. As such, many applications of the regulatory test do not undergo critical assessment by interested parties. This means that there is some uncertainty as to how the regulator will assess these applications of the regulatory test at the end of the regulatory period.

3.4 Intrusiveness of current approach

As noted above, the Commission has the ability to optimise inefficient investments from the TNSP's asset base. The Draft Regulatory Principles provides that "prudent expenditures that were required and took place, but were not previously forecast, will be rolled into the regulatory asset base"[7] and that the Commission's ability to optimise inefficient investment would "provide the market discipline to write-down an inappropriate investment".[8] The optimisation authority is also established in the Code. Therefore, if the costs of projects were higher than forecast, then the Commission would undertake a project-specific assessment of the prudency of those projects. It merits noting that the Draft Regulatory Principles explicitly recognised that forecast capital expenditure was likely to differ from actual capital expenditure[9] and thus envisaged that project-specific efficiency assessments would be necessary.

This has definite implications for the shape of the regulatory regime to be adopted. The Commission's task in determining which projects are efficient is not a

[7] Draft Regulatory Principles, page 64.
[8] Draft Regulatory Principles, page 43.
[9] Draft Regulatory Principles, page 95.

straightforward task. It requires detailed analysis and potentially involves a time and resource intensive analysis of the costs and benefits of each project. In the context of the current TransGrid and EnergyAustralia revenue resets, the Commission is having to assess the adequacy of the regulatory test processes undertaken by TransGrid and EnergyAustralia across a range of projects. The Commission is discovering that this is potentially an extremely intrusive form of regulation.

Such a project-specific approach has been criticised because of the degree of intervention it implies in the day-to-day decisions of TNSPs. It requires the regulator to be closely involved in determining the appropriateness of key business investment decisions. This degree of regulatory intervention in the operation of commercial enterprise is seen by some as intrusive and interventionist on the part of the regulator and inappropriate in the context of a light-handed regulatory regime. Such a degree of intervention may also potentially impinge on the ability of TNSPs to meet their statutory obligations.

In fact, it would appear that an approach that relies on an ex-post assessment of a TNSP's individual projects is moving away from an incentive-based regime. The level of detail that the regulator is required to go into to assess whether a TNSP has applied the regulatory test correctly essentially involves micro-management of the TNSP's decision-making processes. This shares much in common with a rate of return regulatory approach.

4. Options for the reform of transmission investment regulation

4.1 Introduction

This section considers options for the reform of transmission investment regulation. Given the issues associated with a regulatory approach based on project-specific assessments, the Commission believes that it may be appropriate to move towards a model based on a firm ex-ante cap on investment. This analysis leads to a discussion of the preferred approach and issues associated with its implementation.

4.2 The ex-ante cap regulatory approach

The Commission believes that it may be appropriate to move away from an approach based on project-specific regulation to an approach based on a firm ex-ante cap on the total investment for the forecast period.

The ex-ante approach would involve the TNSP proposing a five-year capex allowance, which would be assessed by the Commission. The Commission would establish a firm cap at the start of each regulatory control period. This would be expressed as a profile of spending for each year of the control period, rather than as a specified list of investments and their expected costs. TNSPs would be free to decide which projects to build and when to build them with the knowledge that as long as the aggregate cost of those projects is less than the cap, then they are authorised to recover the cost of these investments through regulated charges. However, if a TNSP invests more than the cap, this additional investment will not be included in its regulated asset base.

This investment cap would be established on the basis that it represents the level of spending necessary to ensure that a prudent TNSP is able to meet its statutory and Code obligations, taking account of the likely changes in the factors driving the need for and cost of investment. The profile of capped spending will be included in the determination of revenues for the regulatory control period.

The potential benefits of this approach are that, depending on how it is applied, a firm ex-ante cap can help address the issues of regulatory intrusiveness and uncertainty for investors, which were discussed in the previous section.

Concerning regulatory intrusiveness, once the firm ex-ante cap is set, the TNSP would not be subject to any project by project assessment by the regulator. The cap would not outline which projects must be developed and the regulator would not intervene to define how the TNSP should allocate its funds between competing projects. This approach is likely to be a more "light handed" approach to the regulation of capex than a project-specific assessment.

Concerning regulatory uncertainty, there would be no ex-post optimisation of the TNSP's investments under the cap. Provided that the cost of its projects is less than the cap, there is no risk that the regulator will attempt to assess the prudency of the TNSP's investments at the end of the regulatory period.

Issues for consideration

Interested parties are invited to comment on the merit of the Commission setting a firm capex allowance on an ex-ante basis.

4.3 Implementation Issues

A first issue associated with a shift to an ex-ante approach concerns the basis on which the cap is set. There are a diversity of approaches with varying degrees of rigour that could be used to assess allowed investment limits with an ex-ante cap regime. One approach would be to undertake a very detailed review of firm-specific conditions to attempt to assess the prudent level of future investment. In establishing the price cap on regulated network businesses in Britain, Ofgem conducts a detailed assessment of the firm's investment needs and then determines what it deems to be the efficient level of capital expenditure for the future control period. This is likely to be a comparatively resource-intensive approach.

Another approach would be to rely less on firm-specific analysis, and more on other information, such as historic expenditure levels, benchmarks or other comparative assessments or economy-wide efficiency measures. This approach can be expected to be comparatively less resource intensive (although this is not necessarily the case). For example, in establishing the price caps for regulated electricity network companies in Holland, Dte, the Netherlands electricity regulator uses econometric methods to determine price changes required to bring firms closer to what it deems to be the frontier level of efficiency.

The Commission believes that the capex review process conducted as part of the current "building blocks" approach is a workable basis on which to set an ex-ante cap. However, it would appear that greater rigour would be required in the establishment of a firm cap than currently applies in the determination of the forecast capex allowance, since it would not be subject to ex-post optimisation.

Issues for consideration

Interested parties are invited to comment on the basis on which a firm ex-ante cap should be set.

Assuming that the capex target is set accurately, a second issue concerns the incentive properties of an ex-ante cap. In circumstances where they will retain a share of capex underspend, the TNSP has the incentive to invest less than that provided for in the cap. While the TNSP should be rewarded if this is achieved through improved efficiency, it would be a significant concern if the underspend jeopardised reliability of the network.

A recent Ofgem consultation document highlighted the difficulties inherent in a regime that rewards underspend in an environment where there is a lack of incentives to promote service quality:

> *"Companies also have an incentive to underspend the projected level of capex that is estimated by the regulator as they retain a significant share of the underspend, although this may be offset by financial incentives (and other obligations) on the delivery of outputs. These obligations and outputs include … specific incentives … such as quality of supply. In the absence of output incentives and other obligations, the incentive on a company is therefore not to invest as they earn a greater return from the price control from taking this decision."*[10]

In the NEM at present, the TNSPs have to meet statutory reliability requirements. Therefore a critical issue is whether these reliability requirements and others that may be subsequently developed provide sufficient safeguards to ensure that any capex spending reductions are not achieved at the expense of service quality.

If capex underspend is achieved while reliability levels are maintained, the issue then becomes one of what benefit sharing mechanisms should be put in place. There are a variety of potential measures that could be adopted. At one end of the spectrum, an incentive scheme could be put in place whereby if the TNSP invests less than that provided for under the cap, it retains any underspend during the period. However its actual level of investment would be rolled into the regulatory asset base. This would generally create strong incentives to minimise capex spending.

At the other end of the spectrum, a scheme could be put in place whereby if the TNSP invests less than that provided for in the cap, it does not retain any of the underspend. Such a scheme does not create any incentives for the TNSP to minimise capex spending. In fact, TNSPs would have the incentive to spend up to the level of the cap.

There are a variety of incentive schemes that could be developed which fall between these two extremes. The Commission seeks the views of interested parties on the incentive scheme that they believe is appropriate.

Issues for consideration

Interested parties are invited to comment on whether statutory reliability requirements provide sufficient safeguards against an inefficient capex underspend.

Interested parties are invited to comment if there are any other mechanisms that provide safeguards against an inefficient capex underspend.

[10] Ofgem (2003), *Developing network monopoly price controls: Initial conclusions*, June 2003, p 33.

If they do not believe that the statutory reliability requirements or other mechanisms provide these safeguards, interested parties are invited to comment on how these service quality incentives could be set.

Interested parties are invited to comment on the benefit sharing mechanisms that could be put in place to deal with capex underspend.

5. Operation of an exclusions regime

5.1 Introduction

This section will explore in further detail the implementation of a firm ex-ante cap, by discussing whether it is appropriate to apply the ex-ante cap to all TNSP investment.

One drawback of a pure ex-ante approach is that while some capex is predictable, such as replacement capex, other investment is lumpy and cannot be accurately predicted. Therefore, a more appropriate ex-ante cap could be established by excluding certain projects from the ex-ante cap. In such circumstances, all projects excluded from the cap would need to be subjected to project-specific assessment.

While this has some intuitive appeal, as the number of excluded projects increases, so too does the need for project-specific assessment. In addition, for each exclusion, it is necessary to develop administrative arrangements to ensure that the cost of the excluded project (and any consequential investment) is not included in the ex-ante cap. Deciding whether or not to exclude specific projects from the ex-ante cap therefore appears to be a trade-off between the benefit of a potentially more accurate ex-ante cap, and detriment of additional administrative controls and increased project-specific assessment.

There are a number of possible ways to distinguish investments that could be included in the ex-ante cap, from investments that could be subjected to project-specific approval. Specifically, should:

- intra-regional investments be included in the cap, but inter-regional investments be subjected to project-specific approval;

- small network projects be included in the cap, but large network projects be subjected to project-specific approval;

- investment to replace aged assets (i.e non-augmentation investment) be included in the cap, but augmentation investment be subjected to project-specific approval;

[12] Inter-regional investment is not necessarily just the physical infrastructure that crosses the boundaries between TNSPs, but can also be augmentations of the network within the boundaries of a NEM region that has the effect of increasing the transfer capacities between regions. Such intra-regional investment may be justified partly on the grounds of the increased inter-regional transfer capacity that it provides, but partly also on the basis of the benefits - such as improved reliability and increased intra-regional transfer capacity - that it provides to transmission users within the region. The Commission believes that there appears to be no simple answer to this issue and notes that the IRPC is currently tasked with distinguishing between intra-regional and inter-regional investment. Rather than developing rigid rules to determine the inevitably arbitrary classification of investment as intra-regional or inter-regional, the Commission believes it appropriate to deal with this problem on a case-by-case basis subject to the over-riding principle that the classification of investment that meets intra-regional needs and also augments inter-regional capacity, should be based on its main purpose. This definitional issue merits further detailed consideration and we propose to do this in light of comments on this Supplementary Discussion Paper.

- investment planned to meet statutory reliability requirements be included in the cap, but non-reliability investment be subjected to project-specific regulation; and

- highly certain future projects be included in the cap, but less certain investments be subjected to project-specific regulation.

Each of these is explored in more detail in the remainder of this section.

5.2 Excluding inter-regional investment from the ex-ante cap

The Commission favours a project-specific approach to the regulation of inter-regional investment, with a cap on intra-regional investment[12]. The reason for this is relatively straight forward. The transmission networks that cover the NEM are planned by four independent TNSPs. Their statutory obligations extend to the provision of reliable transmission services within their own area only. The determination of the ex-ante cap in respect of intra-regional investment is therefore directly related to the level of investment needed to ensure that a TNSP is able to meet these statutory obligations efficiently. The incentive on TNSPs established by the cap on intra-regional investments, is therefore to meet their statutory obligations at least cost.

However, TNSPs have no obligation to develop interconnectors to neighbouring regions, or to make intra-regional investments whose main purpose would be to increase inter-regional power flows. Rather, such inter-regional investments are likely to arise as a result of negotiated agreements between neighbouring jurisdictions and their respective TNSPs on the benefits that would arise from such investment, and on the allocation of investment costs between TNSPs. It would be theoretically possible to set an ex-ante cap on proposed inter-regional investments, but without statutory obligations to relate the proposed investments to, it is difficult to see how TNSPs would justify (and the Commission assess) such investments ex-ante.

Finally, interconnector projects are intrinsically less predictable than intra-regional investments. They are driven by NEM-wide cost-benefit assessments and, as discussed, involve multi-region political (and in some cases commercial) agreements. For all of these reasons it would seem that a project-specific regulatory approach is likely to be more appropriate for inter-regional projects.

Issues for consideration

Interested parties are invited to comment on whether inter-regional investment should be excluded from the firm ex-ante cap.

5.3 Excluding large projects from the ex-ante cap

It could be argued that large capital projects should be subject to detailed, project-specific regulatory review. Depending on the small/large cut-off, it will be possible to limit the number of projects for detailed review by the ACCC, and hence ameliorate some of the unattractive consequences that would arise if a project-specific approach was applied to the full intra-regional investment program. This approach may necessitate a change in the current Code threshold of a large and small network asset.

On the other hand, as argued earlier, there is reason to prefer an ex-ante cap to a project-specific approach. For this reason the Commission does not see merit in a "blanket" exclusion of large projects from the ex-ante cap. However, there may be an argument that large investments that are also highly uncertain could introduce significant errors into the ex-ante cap. This is discussed later below.

A further problem with a small/large projects approach is that it may create incentives for gaming. For example, if the TNSP receives a firm cap for its smaller projects, it is incentivised to aggregate a number of smaller projects into a larger project in order to potentially receive additional revenue. This would also have the effect of increasing the number of project-specific assessments that the Commission would be required to undertake.

Issues for consideration

Interested parties are invited to comment on whether large network investments should be excluded from the firm ex-ante cap.

If they believe this to be appropriate, interested parties are invited to comment on the suitable threshold for delineating large and small projects.

5.4 Excluding augmentation investment from the ex-ante cap

It could be argued that the ex-ante capex target should be based on expected *replacement* investment (i.e. investment to replace aged or defective assets) only, since this is more predictable than *augmentation* investment. Replacement capex is likely to be the smaller part of the total investment budget. Therefore an ex-ante cap based on replacement capex is likely to cover a relatively small proportion of total capex only. The main argument for this approach hinges on the possibly greater uncertainty of augmentation investment relative to replacement investment, which may not always be the case.

Issues for consideration

Interested parties are invited to comment on whether augmentation investment should be excluded from the firm ex-ante cap.

5.5 Excluding "non-reliability" investment from the ex-ante cap

It could be argued that "reliability" investments should be included in the ex-ante cap, but that "non-reliability" investments should be subject to project-specific assessment. Intuitively, this option appears appealing as the Code currently distinguishes between reliability and non-reliability augmentation. Further, "reliability" investments are covered by jurisdictional reliability requirements, while other augmentations are not. Therefore, if non-reliability augmentations form part of an ex-ante cap, it could be argued that as there is no link between this investment and the requirement to maintain service standards, it may be in the interest of the TNSP to cut back on this non-reliability investment.

However, in practice the distinction between "reliability" investment and other augmentation investment has proven to be problematic. In 2002 the IRPC was tasked with developing a consistent definition of reliability investment in the NEM, and has not been able to bring this matter to a resolution to-date.

To date all TNSPs, other than VENCorp, have only ever applied the "reliability" arm of the Regulatory Test to intra-regional investments. This suggests that establishing the ex-ante cap on the basis of expected "reliability" augmentations only, will mean that the ex-ante cap effectively covers all (or at least most) intra-regional investment.

But this does not explain why "reliability" and "non-reliability" augmentations should be distinguished. As is set out in the following section, under the ex-ante cap regime considered in this paper the outcome of the regulatory test to intra-regional augmentations (whether "reliability" or "non-reliability" augmentations) has no bearing on the amount of the augmentation to be rolled-in to the regulatory asset base. On the other hand, it could be argued that "non-reliability" projects are more uncertain than "reliability" projects. As is considered later, high levels of uncertainty may justify the exclusion of certain projects from the ex-ante cap.

Issues for consideration

Interested parties are invited to comment on whether non-reliability investment should be excluded from the firm ex-ante cap.

5.6 Excluding uncertain investments from the ex-ante cap

This is likely to be a substantive issue in considering the establishment of a firm ex-ante cap. Consider for example the circumstance in which a single large project could make up a large proportion of a TNSP's expected investment, but that there is only a 50% probability that that project would proceed. In this case, if an amount was provided in the ex-ante cap based on the probability-weighted cost (i.e. 50% probability multiplied by the expected project cost), then if the project did not proceed, TNSPs would effectively be over-compensated through revenue allowed under the ex-ante cap. But on the other hand if the project did proceed, TNSPs would be under-compensated – since the probability-weighted allowance would only cover half the expected cost.

This analysis suggests that all uncertain projects (i.e. probability of proceeding below a high cut-off level) could be excluded from the ex-ante cap and be made subject to project-specific assessment. However, this is not a straight-forward issue. For example, any "under-compensation" due to projects that do proceed (but that were not fully provided-for in setting the cap) may be off-set by "over-compensation" for individual projects that don't proceed (but for which part of the cost at least was included in setting the ex-ante cap).

Further, arrangements to exclude specific projects from the ex-ante cap can become extremely complex. It is likely to be necessary to define the project that is excluded in detail so that the ex-ante cap properly reflects the remaining investment. But some large projects may involve investments in various parts of the network and in a wide range of equipment (lines, transformers, switch-gear etc.). Some of the investment that makes up the project may need to proceed anyway, even if the rest of the project does not proceed.[13]

Another problem is that the decision to proceed with many transmission projects is dependent on whether other projects proceed. For example, proceeding with a specific project now, may defer or advance the need to invest in other projects. So even if a defined uncertain large project is excluded from the ex-ante cap, whether or not that project is actually developed can affect other investments that are included in the cap.

Therefore, deciding how to treat uncertain large projects in establishing an ex-ante cap is a complex issue. While there are good reasons to exclude such projects from the ex-ante cap, this creates its own problems. We propose to give this issue further detailed consideration in the light of comments from interested parties to this discussion paper.

[13] For example, a failing substation may need to be replaced even if the main project (for which that substation is part) does not proceed. This raises the problem of judging whether the cost of replacing that substation be included in the ex-ante cap or whether it should be excluded from the cap, along with the rest of the project.

Issues for consideration

Interested parties are invited to comment on whether uncertain investment should be excluded from the firm ex-ante cap.

5.7 Project-specific regulation of investment excluded from the ex-ante cap

Projects that are excluded from the ex-ante cap will be subject to project-specific assessments. The Commission envisages that the following regulatory arrangements would apply for such projects:

- The proponent/s of the project would be expected to conduct the regulatory test for each project, as they do now.

- The proponent/s would be expected to actively liaise with the Commission in the development of the application of the test, and the Commission will issue a determination on whether the project passes the test, *before* investment funds are committed. Suitable procedures and protocols will need to be developed to ensure the smooth working of this arrangement so that the Commission is able to deliver an opinion on the application of the test, shortly after the proponent has completed the test.

- Having completed the regulatory test, the issue is then to determine what amount should be included in the regulated asset base for that project. This issue arises because there may be a variation between the actual design and cost of a project, and the design and cost specified in the regulatory test.

It should be noted that there are potentially significant differences between this application of the Regulatory Test and the current arrangements for the application of the Regulatory Test to augmentations. Firstly, under this potential arrangement the Commission would assess the proponent's application of the Regulatory Test *before* (significant) funds are committed by the TNSP. At present the Commission is not required to comment on the application of the regulatory test, unless the application of the test has been appealed by an interested party. But, through the determination of TNSP revenue controls, the Commission is currently able to "optimise" assets after they have been built.

Second, the development of project-specific incentives would potentially relate the actual cost of a project to the amount of that cost that TNSPs will be allowed to include in their regulated asset bases. At present there is no formal link between the outcome of the regulatory test and the determination of the regulated asset base by the Commission.

Issues for consideration

Interested parties are invited to comment on whether the Commission should assess whether the project passes the regulatory test *before* invested funds are committed.

5.8 Arrangements applicable to separate networks planners and owners

The Commission regulates the revenue of two TNSPs in Victoria. SPI PowerNet is a privately owned company that owns, operates and maintains most of the transmission network. VENCorp is a statutory authority with sole responsibility for planning and directing the augmentation of the shared transmission network. VENCorp does not own any transmission assets itself. Instead, it procures electricity transmission services in relation to augmentation works from SPI PowerNet under long-term Network Agreements. The costs of those augmentation works are then passed onto transmission users via a mechanism that allows it to alter its TUoS charges to deal with fluctuating costs.

SPI PowerNet's regulated revenue is determined by the Commission. However, capex included in SPI PowerNet's control covers investment needed to maintain and replace existing assets only, and does not include provision for augmentations to the network which is covered by the long-term Network Agreement with VENCorp.

The Commission does not envisage any change to the arrangements for the regulation of investment planned by VENCorp in the event that an ex-ante cap is introduced. The main reasons for this are that, unlike other TNSPs, VENCorp is a planning authority only - it has no obligation to develop the projects it plans and does not own those projects. In addition, while it is accountable for ensuring that the most efficient projects are planned and developed, it is not financially accountable if the cost of the project that is developed exceeds the cost of the projects that it planned. Establishing an ex-ante cap on VENCorp would therefore not be appropriate as it exposes them to risks which they are not accountable for.

In the case of SPI Powernet, the Commission proposes to set an ex-ante cap on its maintenance and replacement expenditures. For augmentation investments, there will be no cap on either SPI PowerNet or VENCorp.

6. Off Ramps

6.1 Introduction

The previous section considered the options for distinguishing which projects should be included in an ex-ante cap. This section considers whether it is appropriate to "re-open" the overall investment cap, and discusses the circumstances under which this potentially should happen.

6.2 Are "off-ramps" appropriate?

The Commission believes that the specification of "off-ramps", which would re-open the investment cap, potentially has an important part to play in a broader ex-ante framework. These "off-ramps" would establish conditions under which the investment cap will be "re-opened" during or after the regulatory control period. The Commission believes that the principle of "off-ramps" is that they should protect the TNSP from losses attributable to factors that have caused changes in the necessary (efficient) level of investment, that could not have been foreseen at the time that the cap was established, and over-which the TNSP has little or no control. Further, the Commission believes that it would need to be demonstrated that these events have a material impact on the need for transmission investment. The Commission also considers that the range of "off-ramps" should necessarily be limited and clearly defined. In view of the importance that they are likely to play as a protection against unforeseen events, the Commission seeks the views of interested parties on whether "off-ramps" are appropriate.

Issues for consideration

Interested parties are invited to comment on whether "off-ramps", which establish conditions for re-opening the investment cap, should form part of an ex-ante framework.

6.3 Triggers for off-ramps

If it is accepted that in some circumstances it may be appropriate to re-open the investment cap, the question becomes one of what the trigger for the review should be.

An initial threshold issue is whether the "off-ramps" provision should be utilised in circumstances where a portion of the initial investment cap has not been spent. It could be argued that as the TNSP has not allocated its full capex allowance, the unexpected investment should be funded through the unspent portion of the cap in the first instance. However, it could also be argued that if the TNSP is achieving efficiency gains, it should not be penalised for investment necessitated by factors beyond its control. The Commission seeks the views of interested parties on this issue.

A further issue concerns the events which could trigger the "off-ramps" provision. The Commission believes that typical "off-ramps" may include force majeure events and other specific, identifiable events. These events may include unexpected load growth or unexpected generation. The Commission believes that it would be preferable if the principles of the "off-ramp" could be agreed to ex-ante. The Commission seeks the views of interested parties on whether it is possible to specify the events that would trigger the "off-ramps" provision up front and what these events should be.

Issues for consideration

Interested parties are invited to comment on whether the investment cap should be "re-opened" in circumstances where the initial investment cap has not been fully expended.

Interested parties are invited to comment on what events should be considered under any "off-ramp" provisions.

6.4 "Off-ramps" process

A final issue concerns the process by which the investment cap would be re-opened. Potentially the cap could be "re-opened" on application by the TNSP on a project by project basis. Alternatively, an annual or mid-term review of the TNSP's capex could be introduced, which could develop thresholds for re-opening the cap.

Issues for consideration

Interested parties are invited to comment on the process by which the investment cap could be re-opened.

7. Implications of the proposed investment framework arrangements for the regulatory test

7.1 Introduction

This section considers options for the reform of the regulatory test in view of the proposed investment framework set out in the previous sections. It begins by considering the Code obligations on TNSPs to apply the regulatory test and how the need for this may be affected by the adoption of an ex-ante cap regulatory approach. It then considers the role of the regulatory test in the assessment of projects which sit outside the firm ex-ante cap.

7.2 The role of the regulatory test for projects inside the firm ex-ante cap

The Code currently requires TNSPs to apply the regulatory test to all network augmentations, with different consultation processes for new large and new small network assets. In the case of new small network assets a TNSP will essentially consult on a proposed new small network asset through its Annual Planning Report. The process for the construction of a new large network asset is lengthier and more onerous. The applicant must publish a notice setting out a detailed description of the project. However, unlike small network assets where there is no opportunity for appeal, large network assets can be disputed to either the dispute resolution panel or to the Commission, providing that the augmentation is not a reliability augmentation.

In a framework where a firm cap is set and there are no ex-post reviews of the efficiency of individual projects, the role of the regulatory test is brought into question. The Commission understands that the NEM jurisdictions, as part of their MCE work program, are currently considering this issue and are looking to develop amendments to the Code. The Commission will work with the NEM jurisdictions to assist them determine the case for Code changes and evaluate the effectiveness of any proposals. In any discussions with the jurisdictions, the Commission will take into account all responses received to this paper.

In the absence of Code changes, the Commission believes that the regulatory test could be amended in such a way that it continues to play a valuable role. The regulatory test could be amended to become more a consultative tool for projects within the firm ex-ante cap. For example, it could still continue to provide the market with information on the need for the project, possible alternatives, line routes and their relative costs. However, it would no longer rank the various alternative projects.

This still leaves the role of the Code's dispute processes unresolved. Under a regulatory test which is largely a consultative document, the Commission would see the Code's dispute processes as adding an administrative and regulatory burden on TNSPs for no useful purpose. One solution may therefore be for the Commission to amend the distinction between new small and new large network augmentations[14].

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[14] Chapter 10 of the Code expressly provides the Commission with the ability to amend the distinction of a new large network asset. In particular it states:

Significantly raising the threshold of projects such that they effectively become new small network augmentations would limit the use of the disputes process.

While these solutions have their weaknesses, the Commission believes that they could provide a workable solution in the context of the Code framework.

7.3 The role of the regulatory test for projects outside the firm ex-ante cap

As discussed in Section 6, the Commission envisages that the regulatory test will play a key role in the economic assessment of projects which are not covered by the ex-ante cap. The main difference under an ex-ante framework would be that TNSPs would actively engage the Commission during the application of the regulatory test and the Commission will thereby provide an opinion on whether the project satisfies the test, at the same time that the test is being run. The Commission will also consider whether project-specific delivery incentives should also be established and performance against this incentive will determine the amount of the cost of the project which will be included in the Regulatory Asset Base. This active involvement is similar in many respects to the approach adopted by the Commission in its assessment of the Murraylink Transmission Company conversion application.

There are two issues that will need to be addressed to allow this to happen. The first is the Commission's ability to re-open a revenue cap during a regulatory period. Clause 6.2.4(d) of the Code sets out the circumstances under which the Commission may re-open a revenue cap.[15] As the Code stands at the moment, it would be unable to open a revenue cap to include projects which have been excluded, or those that may be considered necessary under the off-ramp provisions. As before, the Commission will need to work with the NEM jurisdictions to address this issue. Again, without Code changes the Commission may be able to deal with the under recovery of revenue at the regulatory reset by providing an opinion on the legitimacy of the claims during the regulatory period.

An asset of a *Transmission Network Service Provider* which is an *augmentation* and in relation to which the *Network Service Provider* has estimated it will be required to invest a total capitalised expenditure in excess of $10 million, unless the *ACCC publishes* a requirement that a *new large network asset* will be distinguished from a *new small network asset* if it involves investment of a total capitalised expenditure in excess of another amount, or satisfaction of another criterion. Where such a specification has been made, an asset must require total capitalised expenditure in excess of that amount or satisfaction of those other criteria to be a *new large network asset*.

15 Notwithstanding clause 6.2.4(b), the *ACCC* may revoke a *revenue cap* during a *regulatory control period* only where it appears to the *ACCC* that:

(1) the *revenue cap* was set on the basis of false or materially misleading information provided to the *ACCC*;

(2) there was a material error in the setting of the *revenue cap* and the prior written consent of parties affected by any proposed subsequent re-opening of the *revenue cap* has been obtained by the *ACCC*; or

(3) there is a substantial change in ownership of network assets within the business of the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) which, in the opinion of the ACCC, may lead to a material change in the revenue requirement of the Transmission Network Owner and/or Transmission Network Service Provider (as appropriate) following that change in ownership.

The second issue that the Commission would need to address is that the Code currently restricts the Commission's role in regulatory test assessments to the resolution of disputes. If the Commission is to work actively with proponents in the assessment of the application of the regulatory test, this would appear to fetter the discretion of the Commission to subsequently hear any appeals.

There are a number of possible solutions. One approach would be for the Commission to refrain from making any specific assessments until after the deadline for appeals has expired (and assuming no appeal is made before the deadline). A second approach would be to raise the threshold between new small and new large network augmentations, so that effectively all augmentations would be classified as small augmentations. This solution would eliminate the appeals process.

Again, the Commission will need to liaise with the NEM jurisdictions to determine the feasibility of Code changes.

8. Commission's process

The Commission is calling for submissions from interested parties on the issues raised above and any other issues that interested parties believe that the Commission should consider in its review.

Submissions can be sent electronically to: electricity.group@accc.gov.au. Alternatively, written submissions can be sent to:

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

The closing date for submissions is Friday 23 April 2004.

The issues raised in this Supplementary Discussion Paper will be discussed at the *Review of the Draft Statement of Principles for the Regulation of Transmission Revenues* public forum, which will be held on 2 April 2004.

The Commission will consider the comments at the public forum and submissions received in response to this discussion paper in considering whether reform to the capital expenditure regulatory framework is appropriate. It is anticipated that these issues will form part of the capital expenditure section of the Draft Regulatory Principles, which should be released mid-year.

UNDERSTANDING THE ROLE FOR RELATIVE PRODUCTIVITY INFORMATION IN NATURAL MONOPOLY REGULATION IN AUSTRALIA

Darryl Biggar

11 October 2005

1. In the course of regulatory debate in Australia it has often been argued that regulators should move towards greater – or even exclusive – reliance on measures of long-term industry-wide productivity trends in setting the revenue requirement for regulated network businesses in Australia.[1]

2. However the debate over the appropriate role for productivity-based regulation has been clouded by misunderstandings over the role of the X factor in determining the power of the incentives in CPI-X regulation and a lack of precision over exactly how the relative productivity or efficiency information will be used. Advocates of productivity-based regulation emphasise the role that productivity information can play in creating high-powered incentives for productive efficiency, but are high-powered incentives always desirable?

3. This paper seeks to clarify the debate over the appropriate role for productivity information in network regulation in Australia. Should TFP or DEA techniques be a core part of the regulatory regime for regulated networks in Australia? If so, how should they be used?

4. In brief, I argue that:

- The role of the X factor in creating incentives for productive efficiency has been widely misunderstood. The power of the incentive to reduce expenditure depends on how both the "P0" factor and the X factor are set, and not on the X factor alone. Using productivity information to set the X factor will have no necessary impact on incentives whatsoever. The observation that other jurisdictions use productivity information to set the X factor tells us nothing about the incentive properties of the associated regulatory regime.

- Advocates of the use of productivity information sometimes give the impression that high-powered incentives to reduce expenditure are optimal. Economic theory does not allow us to conclude that high-powered incentives are optimal. Higher-powered incentives are associated with higher profits and/or higher risk on the regulated firms. In the presence of information asymmetry the optimal power of the incentive to reduce expenditure will balance incentives for productive efficiency and excess

[1] See, for example CitiPower (2001a): "If regulation is to create the correct incentives, it must allow companies to benefit through higher earnings when efficiency improves. Ultimately, this goal is only achieved through the use of external performance measures, which create the strongest possible incentives, maximise long-run customer benefit, and enable returns to be commensurate with company performance", page 2.

profits or risk on the regulated firm. In addition, higher powered incentives may undermine service quality and may not be sustainable.

- Putting aside the cost of collecting the productivity information, relative productivity performance information will almost always reduce the information asymmetry faced by the regulator firm, thereby reducing the trade-off between the power of incentives and risk or rent-extraction, and allowing for higher-powered incentives without undue risk or undue rent left to the regulated firms.

- The use of relative productivity information is not mutually-exclusive to the use of firm-specific cost information. Rather, both sources of information are complementary. If obtaining this information is relatively inexpensive, the optimal regulatory contract is likely to depend on *both* sources of information available to the regulator. The key question is the *weight* given to productivity information in the optimal regulatory contract and how that productivity information is used. In deciding how much weight to give to relative productivity information, consideration must be given to the different sources of error or uncertainty include the potential for problems with the productivity assessment technique, measurement error, misspecification of inputs and outputs, and incorrect assumptions about the nature of cost shocks facing different firms.

- The information content of relative productivity information will vary from industry to industry and across comparator firms and will depend on factors such as the extent to which comparator firms are subject to common shocks in, say, their production technology, or in their input costs. Unfortunately there is a lack of studies exploring the question of what information can be obtained by comparing productivity across firms or the best way to extract that information. There is scope for further research to determine exactly how much and what sort of information can be gleaned from productivity comparisons across firms.

- The calculation of relative productivity information involves certain fixed costs and the quality of the resulting information will improve the larger the number of comparator firms. On the other hand, the cost of collecting firm-specific cost information is linearly increasing in the number of regulated firms. As a result, the decision to collect and rely on relative productivity information will depend in part on the number of comparator firms and the quality of the information from those firms. Where there is a very small number of comparator firms, it is likely that sole reliance on firm-specific cost information is preferable. For a large number of firms it is likely that sole reliance on relative productivity information is desirable. There may be a range of numbers of firms for which both approaches should be used simultaneously.

5. This paper makes the following recommendations:

(a) That regulators continue to collect standardised and comparable information on the performance of regulated companies in a manner which is useful for relative productivity and efficiency performance evaluation.

(b) That, as a first step, work be carried out to better understand the key cost drivers for electricity distribution businesses, the nature of the cost function of distribution businesses, the best approaches to comparing productivity and/or efficiency across firms and the reliability of those approaches.

(c) That, as a second step, work be carried out to understand the information content of relative productivity information of firms in different sectors. This work would seek to understand how the costs of different transmission and distribution businesses vary over time and relative to each other, and the extent to which different firms are subject to common cost, technology, or demand shocks.

(d) That, as a third step, modelling work be carried out which would assist in understanding the magnitude of the trade-offs between the power of incentives and either risk or rent-extraction that would have arisen under different regulatory mechanisms using the observed patterns of productivity changes which have arisen in the past.

6. This paper focuses on creating incentives for productive efficiency. Other incentives – such as incentives for service quality – are also very important, particularly when high powered incentives for productive efficiency are considered. However, the debate over the merits of productivity-based regulation has focused on the incentives for productive efficiency and for that reason alone, this is where this paper will focus.

An overview of the building block model

7. Almost all the natural monopoly regulators in Australia use the so-called "building block model". Advocates of productivity-based regulation have been critical of the building block model and the incentives it creates.[2] It is therefore important to start by understanding the building block model, how it has been applied in practice, and what we can say about the incentives it creates.

8. In practice the application of the building block model has followed a broadly similar pattern both in Australia and in other countries. The basic building block model is conventionally implemented as follows:

(a) At the beginning of the regulatory period the opening regulatory asset base ("RAB") is determined. This could be either through some external mechanism, such as a DORC valuation or through a "roll forward" of the previous RAB. In the case of a roll-forward, the difference between out-turn and forecast capital expenditure in the previous regulatory period may be taken into account.

(b) Given the expected service quantity and quality required to be delivered over the forthcoming regulatory period, the operating expenditure and capital expenditure

[2] "The building block approach to CPI-X regulation bears an undeniable relationship to rate of return regulation. As in RoR, the building block method is focused on determining a revenue requirement for each regulated firm". CitiPower (2001b), page 2. Productivity Commission (2001), page 343: "The need to forecast future costs and to validate proposed capital expenditure could lead to the regulator having a significant influence over the running of the business" Productivity Commission (2001), page 343: "Such outcomes illustrate the tendency for price caps based on the building block approach to suffer from some of the disadvantages of rate of return regulation. Moreover, subsequent efforts of the regulator to address the downsides of rate of return regulation – incentives to 'gold plate' assets and pad costs – can in turn lead to even more intrusive regulation… ".

of the firm necessary to achieve that quantity and quality is forecast, using information on past expenditure out-turns, advice from engineering experts and comparisons with other firms.

(c) A decision is made on how much of the expenditure of the firm is to be amortised (i.e., recovered) in future regulatory periods and, correspondingly, the level of "depreciation" or "return of capital" in the current regulatory period. The cost of capital is also determined.

(d) The total revenue requirement is computed as the sum of the return on capital, the return of capital, the operating expenditure and possibly other terms including the expected tax expenditure and, in some cases, a carry-over mechanism, which reflects the difference between forecast and out-turn expenditure in the previous regulatory period.

(e) An allowed path of revenue or prices (depending on whether a revenue cap or a price cap is being set) is chosen which yields a present value of the allowed revenue path equal to the present value of the total revenue requirement determined above.[3] This path of revenue/prices is usually described as taking the "CPI-X" form. There is variation between regulators on whether this path of revenue/prices is "smoothed" (in which case the X factor is chosen so as to yield a smooth transition from existing levels) or whether the X factor is set on some other external basis (in which case there is likely to be a discrete "jump" in prices/revenues at the beginning of the regulatory period, known as a "P0 adjustment").

9. Under the building block model, the incentive on the regulated firm to reduce expenditure depends on several different factors:

(a) The length of the regulatory period (almost always five years in practice) combined with the understanding that a reduction in operating expenditure (although not necessarily capital expenditure) will not be "clawed back" in the form of a lower revenue allowance or lower regulatory asset base in the subsequent regulatory period.[4]

(b) The form of the asset-base roll-forward equation. The conventional approach is to roll-forward the asset-base on the basis of forecast depreciation and out-turn capital expenditure. This has the effect of creating some incentives to minimise capital expenditure, while at the same time creating incentives to shift capital expenditure between asset classes.[5] Other approaches are possible and will have different incentive effects.

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[3] Joskow (2005), page 38, describing the practice in the UK notes that "P0 and X are chosen so that the present discounted values of revenues over the five-year period is equal to the present discounted value of the total operating and capital related charges that have been allowed for each distribution company during the price review. The choice of the specific values of P0 and X that satisfies this present discounted value property is a matter of judgement".

[4] The length of the regulatory period is, of course, only relevant if there is some decoupling of regulated revenue and out-turn expenditure over time.

[5] See Biggar (2005)

(c) The manner in which information on past expenditure out-turns is used to set the expenditure targets for the next regulatory period. In particular, will the regulator focus on the expenditure out-turn in just a single year of the previous period, or on all five years of the previous regulatory period? If all five years, then how will this information be used? Will the regulator extrapolate *trends* in expenditure or focus on *levels*? Will the regulator set the expenditure targets on the basis of the observed expenditure out-turns of other firms? Or on the basis of bottom-up models of the existing networks? If the expenditure targets are set on the basis of advice from engineering experts how will those experts, in turn, take into account the observed expenditure out-turns of the regulated firm?

(d) Any "carry-over mechanism" which explicitly links future revenue to the difference between out-turn and forecast expenditure.

10. The building block model has, on occasion, been criticised. Critics have argued that:

(a) The building block model, with its focus on the regulated firm's own costs, is too close to traditional "cost of service" or "rate of return" regulation.[6] In other words, these critics argue, the power of the incentive on the regulated firm to reduce its costs is too low. This has further implications for the regulatory process, specifically, it is argued that:

(i) The low power of the incentive to reduce expenditure leads the regulator to be actively involved in over-seeing the commercial decisions of the regulated firm, leading too a regulatory regime which is too "intrusive".

(ii) The low power of the incentive to reduce expenditure could lead the regulated firm to over-invest in its asset base (i.e., to "gold plate", also known as the Averch-Johnson effect).

(b) The building block model is also criticised as requiring large amounts of information which is costly to produce and to process, and is likely to be contentious and a source of litigation.

(c) In addition, as a result of the focus on the regulated firm's own costs, the building block model is sometimes criticised as facilitating "gaming' of the regulatory process by the regulated firm (that is, to facilitate actions by the regulated firm which exaggerate its revenue requirement in the forthcoming regulatory period).[7]

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[6] See the citations in footnote 2.

[7] As an aside, it is worth noting that there is something of an inconsistency in these criticisms. If the building block regime was genuinely "low powered", the regulated firm would receive revenue equal to its own expenditure out-turn and there would be no incentive to try to game the regulator by exaggerating the firm's expenditure requirement. Under "rate of return" regulation, the firm's revenue allowance depends only on its own expenditure out-turn and not on the target expenditure. There is no value to the firm in gaming the regulator to increase the target expenditure if the firm's ultimate revenue depends only on the expenditure out-turn. In fact, it is easy to verify that the incentive to "game" the regulator to raise the target expenditure is stronger the higher the power of the regulatory regime.

11. What exactly are the incentives created by the building block model? A full analysis of the incentive properties of the building block model is beyond the scope of this paper. However, we can make the following observations:

(a) First, the incentive properties of the building block model are not determined from the information set out above. In particular, the incentive properties of the building block model depend strongly on the manner in which information on past cost out-turns are taken into account when setting the allowed future revenue. As Joskow (2005) notes:

"The dynamic attributes of the regulatory process and how regulators use information about costs revealed by the regulated firm's behaviour over time have significant effects on the incentives the regulated firm faces and on its behaviour".[8]

Theoretically, if the allowed revenue were set on the basis of some mechanism which was completely independent of the cost out-turns of the regulated firm, the building block model could yield very high-powered incentives. It is therefore not possible to assert that the building block model inevitably results in "low powered" incentives. However, it is also not possible to assert that the building block model inevitably results in high-powered incentives to reduce expenditure – it depends on precisely how information on past cost out-turns is used when setting the level and path of future allowed revenue in the building block model.

(b) It is sometimes asserted that, under the building block model, there is a declining power of the incentive for productive efficiency over the course of the regulatory period. In the UK "it has been observed that regulated firms appear to make their greatest cost reduction efforts during the early years of the price cap period and then exerted less effort at reducing costs as the date of the price review approached".[9] Theoretically, this depends on how information on past cost out-turn is taken into account when setting future allowed revenues. It is theoretically possible that the power of the incentive for productive efficiency could decline over the course of the regulatory period. If the future allowed revenue is set primarily on the basis of the expenditure out-turn in the last year of the previous regulatory period (or on the basis of the expenditure out-turn in any single year) the incentive to reduce expenditure in that year is much reduced and may be negative.[10] On the other hand, if the regulator sets the allowed revenue on the basis of the expenditure out-turn in all the years of the previous regulatory period (such as the average), there may be no reduction in the incentive for productive efficiency over the course of the regulatory period.

Along the same lines, it is sometimes argued that an "efficiency carry-over mechanism" is necessary to prevent the decline in the power of the incentive for productive efficiency over the course of the regulatory period. Again, it is not possible to assert this on the basis of the description of the building block model above. It can be shown that it would make sense to include an efficiency carry-over mechanism if and only if the regulator committed itself to set the future

[8] Joskow (2005), page 25.
[9] Joskow (2005), page 25.
[10] See Pint (1992), Biggar (2004).

allowed revenue in each year of the forthcoming regulatory period equal to the expenditure out-turn in the last year of the previous regulatory period.

(c) The incentive to reduce capital expenditure depends primarily on the precise form of the asset-base roll-forward equation. As noted earlier, the conventional approach is to roll-forward the asset-base on the basis of forecast depreciation and out-turn capital expenditure. This gives rise to incentives to delay capital expenditure until the end of the regulatory period, and to substitute projects with longer lives for projects with shorter lives.[11]

12. Beyond these observations, there is not much further that can be said about the incentive properties of the building block model. Overall, it is clear that the incentive properties of the building block model are somewhat murky, in some respects odd, not very low-powered, but neither (at least under normal practice) very high-powered.

The Choice of the X-Factor Does Not Determine Incentives

13. In many cases, it appears that advocates of the use of productivity information consider that the basic structure of the regulatory process outlined above will be maintained except that information on the relative productivity (or productivity trends) of other firms in the industry will be used to set the X factor. But does knowledge of how the X factor is determined in the system above allow us to say anything about the incentive properties of the resulting regulatory regime?

14. As noted in the previous section, the power of the incentive for productive efficiency depends on the extent to which past cost out-turns affect total revenue levels in future regulatory periods. The total revenue allowed to the regulated firm over a regulatory period depends on the path of allowed revenue over the regulatory period. Under the "CPI-X" approach to regulation the path of allowed revenue depends on *both* (a) the allowed revenue in the first year of the regulatory period (also known as the "P0" adjustment) and (b) the X factor, which determines how the revenue (or the price path) evolves from one period to the next.

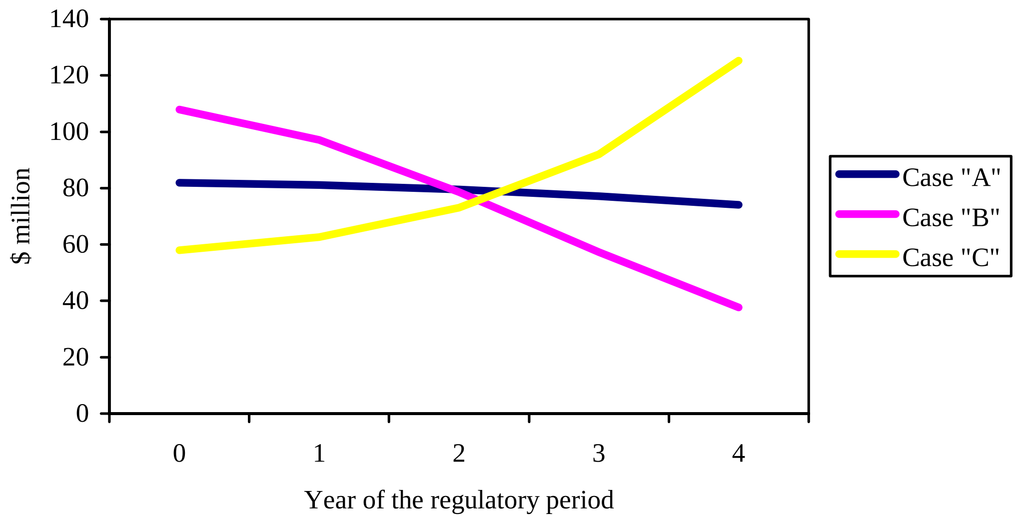
15. It is not possible to determine the total allowed revenue of the regulated firm over the regulatory period without knowledge of *both* the opening allowed revenue and the X factor. As a result, it is not possible to say anything concrete about the incentive properties of a regulatory regime without knowledge of *both* the opening allowed revenue (i.e., the "P0" adjustment) and the X factor.

16. For example, suppose that the regulator determines that, on the basis of information about past cost out-turns and the performance of other firms, the regulated firm will be allowed a revenue with a present value of $300 million in the forthcoming regulatory period. If the cost of capital is 10%, it is possible to achieve a revenue with $300 million in present value in several different ways:

(A) An opening revenue of $81.95 million, and an X factor of 1%;
(B) An opening revenue of $107.91 million, and an X factor of 10%;
(C) An opening revenue of $58 million, and an X factor of -8%;

[11] See Biggar (2005).

Figure 1: Different X factors can yield the same total revenue



17. In all three cases, if the relationship between the past cost out-turns and the future allowed revenue is identical, the incentive properties of each of these three cases is identical. *The X factor alone has no impact on the incentive properties of the regulatory regime.*

18. Unfortunately, there seems to be a fundamental misunderstanding, either explicit or implicit, over the role of the X factor in determining incentives. This view can be seen clearly in the following extract from the ACCC's 1999 Draft Statement of Regulatory Principles:

> "If the TNSP can achieve efficiencies greater than those allowed for in the X factor it retains the higher level of profits. In other words, the benefits of efficiency gains are shared between the consumer (those gains achieved up to the X factor) and the TNSP (the gains achieved in excess of the X factor). *The strength of the incentive effect will be determined in part by both the level of the X factor* and the type and timing of sharing arrangements that the regulator puts in place."[12]

19. A closely related idea is the notion that the power of the incentive depends on "outperforming" the X factor. This idea can be found even in fairly recent documents:

> "A key feature of CPI-X regulation is the incentive for the network provider to out-perform X since this will increase profits".[13]

> The use of TFP has the potential to "increase the incentives on monopoly service providers to … outperform an industry-wide, rather than a firm-specific, cost benchmark".[14]

20. Another related idea is the notion that, even if the level of the X factor is not directly important for incentives, *the way the X factor is determined* will directly affect the incentives.

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[12] ACCC (1999), pages xv and 86, emphasis added. The ACCC has subsequently issued a revised Statement of Regulatory Principles, ACCC (2004).
[13] Utilities Commission (2003), Page 11.
[14] ESC (2004)

21. This idea is expressed, for example, in a recent paper of the Essential Services Commission of Victoria which notes that they intend to initiate a project to "evaluate … the use of TFP indexes in determining the X-factor under a CPI-X approach to price cap incentive regulation"[15]."The TFP approach … bases the rate of change of prices permitted during the regulatory period (that is, the X factor) on an estimate of the historical productivity improvement in the regulated industry".[16] At the same time, the Essential Services Commission makes it clear that the firm-specific cost information will continue to be used to set the "P0" factor, noting that: "regardless of the method used to determine the on-going rate of change in costs, a starting point from which the rate of change in prices would apply needs to be determined – generally by reference to that firm's own costs".[17]

22. However, as we have seen, knowledge that the information on productivity trends is used to set the X factor tells us precisely nothing about the incentive properties of the regulatory regime. Without knowledge of precisely how the "starting point" prices or revenues are determined by reference to a firm's own costs it is impossible to say anything concrete about the incentive properties of the regulatory regime. The regulatory regime proposed here by the ESC might have incentive properties which are stronger, weaker or the same as the building block model. We just cannot say.

23. This misunderstanding over the role of the X factor has a couple of important implications which are worth drawing out.

(a) First, the observation that the incentive properties of a regulatory regime cannot be determined from knowledge of how the X factor is set alone has important implications for what we can learn from overseas regimes.

Advocates of TFP regulation sometimes point to the fact that productivity information is often used to set the X factor in other countries. For example CitiPower (2001) cites experience from California, Massachusetts and Ontario and notes that:

"CitiPower believes that this experience is also valuable for Australia. TFP has clearly played an important role in CPI-X plans that have been approved for North American power and gas distributors. Regulators have also shown a decided preference for using industry TFP trends. In every case above but one, the industry TFP trend was the calibration point for the X factor".[18]

Again, the knowledge that jurisdiction Y uses TFP calculations to set the X factor tells us precisely nothing about the incentive properties of the regulatory regime – they may as well have set the X factor on the basis of the number of sunspots. To understand the incentive properties of the regulatory regime we need to know how the total revenue is set, not just how it varies from one year to the next.

This, of course, also has important implications for the extent to which these other countries are role models for regulation in Australia. These countries may

[15] ESC (2004a), page 9, ESC (2004b).
[16] ESC (2004a), page 9, ESC (2004b)..
[17] ESC (2004a), page 10.
[18] CitiPower (2001b), page 25.

be good role models – but we cannot know that from knowledge of how they set the X factor alone.

(b) Another important consequence of this misunderstanding over the role of the X factor relates to the implications for the continuity of the path of prices/revenues.

If the X factor is set on the basis of some external factor (such as productivity trends), the regulator cannot use X to "smooth" the path of prices. This can lead to a path of prices with discrete jumps or discontinuities at the start of a new regulatory period.

For example, the Essential Services Commission of Victoria, in its most recent draft decision on price controls for distribution networks in Victoria, has proposed a "P0" price reduction of 20.3% on average, and an X factor of 1.44% on average.[19] This implies a fairly substantial discontinuity in prices at the start of the regulatory period. Presumably it would be easy to determine an alternative path of prices which did not involve such a substantial price discontinuity, but which maintained exactly the same incentive properties and overall revenue as the existing regime.

It is easy to find other examples of the same phenomenon. For example, in the UK, in the regulation of the prices for gas transmission, Ofgas originally recommended that prices be cut by 20% immediately and that the X-factor be set at 2.5%. After an appeal to the Monopolies and Mergers Commission, the MMC decided that Transco's rates should be reduced immediately by 21% and that the X-factor should be set at 2%. If we value a smooth path of prices it is difficult to see why such a large price discontinuity was imposed. Again, presumably it would have been easy to determine an alternative smoother path of prices with exactly the same incentive properties and overall revenue as the proposed regime.

24. In summary, the belief that the X factor alone determines the power of the incentive for productive efficiency (a) has led to a focus on the use of productivity information in setting the X factor in Australia; (b) has incorrectly focussed attention on approaches to setting the X factor in overseas jurisdictions; and (c) has led regulators to set the X factor independently of the opening revenue, leading to larger jumps in prices than are strictly necessary.

High-powered incentives are not usually optimal

25. In some cases, it is clear that advocates of productivity-based regulation intend that the productivity information will not be used to *only* set the level of the X factor but also to set the opening level of the prices/revenues (that is, the "P0" factor). In other words, the productivity information would be used to set the entire revenue stream of the regulated firm, completely independently of its own expenditure out-turn. For example, CitiPower (2001a) notes:

> "Whenever the CPI-X formula is designed at least in part to bring returns to target levels, there is a blending of cost-of-service and CPI-X regulation. … CitiPower … recommends that any over- or under-recovery of costs be dealt with immediately at the outset of the

[19] See ESC (2005), page 18, Table A.5.

> price control plan, so that regulators can begin the transition to external regulation. When the controls are subsequently reviewed, they should not reference the company's own returns but rather should be based on external performance standards".[20]

26. If productivity information was used to set both the level and the rate of change of the path of allowed revenue[21], the regulated firm's revenue and its own costs would be decoupled entirely, resulting in a very high-powered incentive mechanism. The view that a high powered incentive mechanism is optimal can be found in several of the submissions to the Productivity Commission review of the National Access Regime.

> "While the [Productivity Commission] position paper moves away from the dictum that prices must match or track costs, it still requires periodic cost-based resets. This is not necessary under a number of forms of 'true' incentive regulation where the reference point is industry or international benchmarks".[22]
>
> Once initial prices are set using a cost of service / rate of return approach CitiPower "maintains that it is not necessary to have additional cost of service reviews" in the future.[23]
>
> "Regulators should be required to include strong incentives for producers to achieve productivity improvements".[24]

27. But is it the case that a very high-powered incentive to achieve productive efficiency is optimal? In fact, economic theory does not demonstrate that a high-powered incentive is always optimal. As set out in the appendix, in the presence of information asymmetry there is a trade-off between the power of the incentive and rent extraction (in the "adverse selection" approach to the regulatory problem) or a trade-off between the power of the incentive and risk (in the principal-agent" approach to the regulatory problem).

28. In the "hidden information" or "adverse selection" model of regulation, there is a trade-off between the power of the incentive and rent-extraction. That is, higher-powered incentive schemes induce the firm to exert higher levels of effort to reduce costs, but leave the regulated firm with high levels of excess profit, on average. The power of the optimal regulatory contract must balance these competing factors. In fact, under the "adverse selection" approach to regulation the optimal choice of the power of the incentive is higher:

(a) the lower the welfare loss from allowing the regulated firm to retain excess profit (i.e., the lower the distortion caused by above-cost pricing);

(b) the better the quality of the information available to the regulator about the effort of the regulated firm.[25]

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[20] CitiPower (2001a), page 13.
[21] or if one or the other were set by some other approach independent of the costs of the regulated firm…
[22] Energex (sub DR81, page 5).
[23] CitiPower (2001b), footnote 14, page 18.
[24] AusCID (sub DR80, page 39).
[25] Beato and Laffont (2002) write: "Monitoring of effort generally enables the regulator to reduce the information rents and calls for higher-powered incentive schemes. A less-efficient monitoring technology will call for relatively less powerful incentive schemes. Indeed, low incentives and monitoring are substitute instruments to extract the firm's rent". Page 7.

(c) The marginal cost of managerial effort to reduce expenditure.[26]

29. Laffont and Tirole (2000) explain this as follows:

> "There is a basic trade-off between incentives, which call for a high-powered incentive scheme, and rent-extraction, which requires, in the presence of adverse selection, low-powered incentives.
>
> This simple implication of the theory is too often forgotten. High powered incentive schemes … have been hailed as a breakthrough in the economics of regulation. While they indeed deliver a good cost performance, they are also likely to leave substantial profits to the firms' owners. There is no magic cure. Those who support or just accept the use of high-powered incentive schemes should be ready to refrain from forcing contract renegotiation when they observe large profits. Experience (the 1995 early review of the UK regional electricity companies is a case in point) shows that this point is not always understood".[27]

30. This same point is made in a paper by Schmalensee (1989) in which he uses modelling to determine the optimal regulatory mechanism under a range of different choices of parameters. He notes that:

> "Generally, this study suggests that price caps have been oversold relative to simple alternatives … . Regimes in which prices depend in part on actual costs may provide weaker incentives for productive efficiency, but nonetheless generally perform better in the presence of cost uncertainty and asymmetric information about the capabilities of regulated firms. Regimes involving cost sharing are better than price caps at limiting the profitability of regulated firms and they allow prices to track costs more closely. …
>
> This study found that the parameters of best-linear regulatory regimes are sensitive to the level of uncertainty regarding both cost-reduction opportunities and future costs. Price caps are an extreme form of linear regulation and are apparently the best-linear regime only in the limit as uncertainty vanishes. Higher levels of uncertainty tend to make greater dependence on actual costs optimal; very high levels of uncertainty may make cost-plus regulation superior to any linear scheme that provides incentives for cost reduction. In general, pretending that the future is certain, a practice common in policy debates, is almost certain to lead to error. Intelligent design of regulatory regimes requires explicit analysis of risk and uncertainty".[28]

31. In the "principal-agent" approach to the regulatory problem there is a trade-off between the power of the incentive and the risk to which the regulated firm is exposed. Under this approach, the higher the power of the incentive to reduce costs, the higher the risk borne by the

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[26] Beato and Laffont (2002): "In practice, costs are not perfectly observable and one must also take into account the possibility of cost padding, i.e., the many ways in which a firm can divert money. Cost can now be increased by undue charges, which benefit the management and the workers. The analysis shows that the imperfect auditing of cost padding calls for a shift towards high-power incentive schemes. In the extreme, if auditing did not exist, only fixed price contracts would be possible. Indeed, they would be the only ones preventing unlimited cost padding by making firms residual claimants of their costs", page 10.

[27] Laffont and Tirole (2000), page 41.

[28] Schmalensee (1989), page 434-5.

regulated firm. As before, the optimal choice of the power of the incentive is therefore a trade-off or a "balance" between different competing objectives. Chong (2004) writes:

> "As is now well-known in the literature, the optimal contract when the principal is only concerned with a single agent depends crucially on the agent's attitude towards risks. It can be shown that when the agent is risk-averse, and assuming that the principal is risk-neutral, then the principal will have to trade off risk-sharing and providing incentives." [29]

32. The impact of higher-power incentives on risk is also emphasised by, for example, Forsyth (2001) [30] and Sappington (2000)[31]. In this context the "incentive intensity principle"[32] shows that the optimal power of an incentive is higher:

(a) the better the quality of the information available to the regulator about the effort of the regulated firm – that is, the degree of "noise" in the signal that the regulator has about the effort of the regulated firm;

(b) the more tolerant the regulated firm is to risk;

(c) the lower the cost to the regulated firm of exerting effort to reduce its expenditure;

33. In summary, a high-powered incentive *may* be optimal, but only if either (a) the regulator can accurately measure the effort of the regulated firm; or (b) the regulated firm cares little about the risk it bears; or (c) the cost to the regulated firm of exerting effort is very low. In general, the optimal power of an incentive mechanism will typically lie somewhere between the extremes of a very low power and a very high power incentive. Economic theory does not allow us to assert that a high-powered incentive is always optimal. Joskow (2005) summarises:

> "A pure price cap without cost-sharing … is not likely to be optimal given asymmetric information and uncertainty about future productivity opportunities. Prices would have to be set too high to satisfy the firm participation constraint and too much rent will be left on the table for the firm. The application of a ratchet from time to time that resets prices

[29] Chong (2004), page 5. In the case where the agent is risk-neutral there is no trade-off between insurance and incentives.

[30] See, for example, the submission of Prof Forsyth to the Productivity Commission he notes: "The extreme opposite to cost-plus regulation is regulation which pays no attention at all to the firm's own costs. … This form of regulation is not costless; it imposes considerable risk on the firm, and risk is costly. Since prices are not related to actual costs, there is a risk that prices will fail to cover costs and the firm will be driven into bankruptcy. … While yardstick regulation provides stronger incentives for productive efficiency, it involves more risk, not just for the firm but also for the regulator". Submission to the PC (cited on page 349).

[31] Sappington (2000), page 32 writes: High-powered incentives "shift risk from consumers to the regulated firm. Although this shifting of risk can help to motivate the firm to operate diligently, it can also raise the firm's cost of capital. Investors typically demand higher expected returns as the risk they are asked to bear increases. Consequently, another potential drawback to incentive regulation is that it can raise the cost of capital".

[32] See Biggar (2005b).

to reflect observed costs is a form of cost-contingent dynamic regulatory contract. It softens cost reducing incentives but extracts more rents for consumers".[33]

34. Even more importantly, high-powered incentive schemes give rise to certain problems which must be taken into account but which are not directly modelled in the analysis above. Specifically:

(a) high-powered incentive schemes may induce the regulated firm to divert attention away from other desirable objectives, such as maintaining service quality;

(b) high-powered incentive schemes may not be sustainable – that is, they may require the regulator to make commitments which it cannot maintain ex post;

(c) high-powered incentives may increase the incentives on the regulated firm to game the regulator in order to raise the "target" or forecast expenditure; and

(d) high-powered incentive schemes make regulatory capture more attractive to the regulated firm and therefore more likely.

The "Balance" Principle

35. It has often been pointed out that a high-powered incentive to reduce expenditure may induce the firm to substitute effort away from other desirable objectives, such as maintaining service quality:

> "A well-known drawback of high-powered schemes is that they make it very costly to firms to supply quality. The provision of quality raises cost and is therefore borne entirely by the firm if the latter is residual claimant for its cost performance. The firm may, therefore, decide to skimp on quality if quality is not minutely specified in the regulatory contract. In contrast, low-powered schemes, by failing to make the firm accountable for its cost performance, make it very cheap to supply quality".[34]

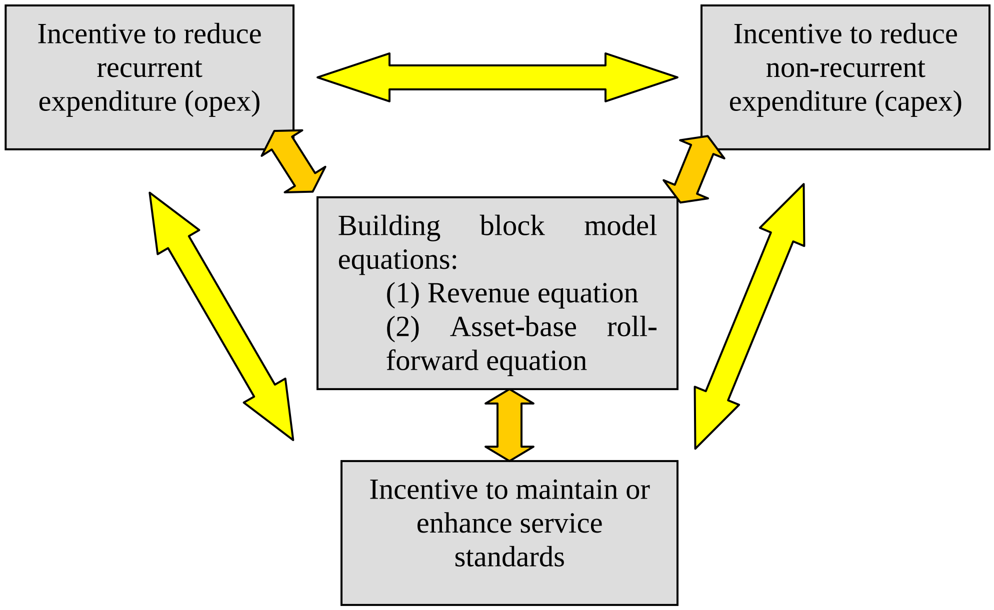
> "Another drawback of high-powered incentives stems from the strong incentives it can provide to reduce operating costs. One common way to reduce costs is to reduce service quality. For example, a telecommunications supplier may reduce its repair and customer assistance staffs in order to limit the wages and benefits it pays to its employees. Such staff reductions can cause service quality to decline below historic levels. If historic levels of service quality do not exceed ideal levels, then the resulting decline in service quality under [high powered incentives] can reduce welfare".[35]

36. As emphasised in, for example ACCC (2004a), the regulator must ensure that there is an overall balance in the incentives created by the regulatory regime. This includes not only balance between the incentive to reduce expenditure and the incentive to maintain service quality, but

[33] Joskow (2005), page 35. See also: "It is … fairly clear that pure 'forever' price cap mechanisms are not optimal from the perspective of an appropriate trade-off between efficiency incentives and rent extraction'", page 34.
[34] Laffont and Tirole (2000), page 54.
[35] Sappington (2000), page 32.

where there are different incentives on different components of expenditure, a balance between, say, incentives to reduce capital expenditure and incentives to reduce operating expenditure. The inter-linkages between these different incentives has been emphasised in the following diagram from ACCC (2004a).

Figure 2.1: Key linkages between different elements of the regulatory framework



37. Given the need for balance between these different incentives, where it is not possible to establish, say, a high-powered incentive to maintain service quality it follows that it is not possible to establish a high-powered incentive to reduce expenditure.

Regulatory Commitment

38. It is widely accepted that, the longer the regulatory period, the stronger the power of the incentive to reduce expenditure. As noted earlier, in practice regulators in Australia use a five-year regulatory period, but often regulators will attempt to extend the effective length of the regulatory period by attempting to commit to not use information which becomes available to them over the course of the regulatory period.

39. The "efficiency carry-over" mechanism is one such commitment – under the efficiency carry-over mechanism the regulator in effect promises to allow the regulated firm to keep any efficiency gains for five years whenever they occur in the regulatory period. Alternatively, the regulator might promise to "glide path" any efficiencies by not adjusting prices fully to revealed cost out-turns at the end of a regulatory period. Both of these regulatory promises have the effect of extending the effective length of the regulatory period.

40. However, these regulatory promises may not be sustainable. In fact it might not even be possible to maintain the original commitment to a five-year regulatory period. As we have seen, higher powered incentives increase the risk on the regulated firm and/or the rent that must be left to the regulated firm on average. Ex post it may turn out that the regulated firm is making either

an exceptionally large return or is failing to break even. In either case the government or the regulated firm might seek to renegotiate the regulatory contract. In a famous case in the UK, Ofgem in 1995 was forced by the government to re-open the price caps on electricity distribution companies and tighten the price path. Laffont and Tirole (2000) write:

> "In practice, the actual length of the regulatory contract may be shorter than its formal length. That is, the contract may be renegotiated before the next regulatory review. On the one hand, the regulator, usually under political pressure, may be tempted to force the firm to renegotiate before the end of the contract when the latter makes substantial profits. Such renegotiation exacerbates the ratchet effect and makes the firm even more cautious about taking full advantage of (formally) high powered incentives to reduce cost. On the other hand, the firm may force the regulatory to renegotiate midway and offer more favourable terms if the initial contract proves unprofitable and makes credible the threat of bankruptcy or at least that of forgoing investments that the regulator deems necessary. The firm is then said to face a 'soft budget constraint' since it is rescued by the regulator despite a commitment not to intervene before the next regulatory review".[36]

41. A regulatory regime which, on the face of it, imposes higher-powered incentives requires the regulator to commit to not re-opening the regulatory contract. Where this commitment is not credible the power of the resulting incentives will be mitigated. If the regulator cannot commit to maintaining the existing regulatory contract it will not be able to establish a high-powered incentive to reduce expenditure.

The Target Principle

42. The higher the power of the incentive on the regulated firm to reduce its expenditure, the greater the extent to which the final revenue of the regulated firm depends on its initial target expenditure and therefore the greater the incentive on the regulated firm to take actions to increase that target expenditure. In other words, the higher the power of the incentive on the regulated firm the greater the incentive on the firm to "game" the regulator by making claims about an increased need for expenditure in the future – whether this is due to increased demand, increased maintenance, increased renewals, or a need for network expansion.

43. If the regulator is not able to adequately contest these claims by the regulated firm, the firm may be able to be systematically over-compensated. The regulator may prefer to weaken the power of the incentive in order to moderate the incentive on the regulated firm to game the system.[37]

Regulatory Capture

44. Relatedly, the regulated firm may be able to obtain a higher target revenue not by making claims about the need for increased expenditure but by altering the incentives of the regulator. This might include various forms of implicit or explicit inducements on the regulator to be lenient in the setting of the target. This is one form of what is known as "regulatory capture". Where

[36] Laffont and Tirole (2000), page 55-56.

[37] It is worth noting that under one form of yardstick competition the regulated revenue of a firm is set equal to the cost out-turn of a comparator firm. Using this approach the regulator can, in principle, both increase the power of the incentive and reduce the ability of the regulated firm to manipulate the target revenue, effectively "killing two birds with one stone".

detecting and preventing this form of collusion is difficult, it may be preferable to adopt lower-powered incentive schemes.[38]

Summary

45. In summary high-powered incentives will not necessarily be optimal. High-powered incentives involve higher risk and/or higher rents left to the regulated firm. Higher-powered incentives to reduce expenditure also place greater pressure on other incentives (such as the incentive to maintain quality). Higher-powered incentives give rise to commitment problems and enhance the incentive for regulatory capture. It is not possible to assert that high-powered incentives to reduce expenditure are always preferred over low-powered incentives:

> "There is a lot of loose and misleading talk about the application of price caps in practice. From a theoretical perspective the infatuation with price caps as incentive devices is surprising since price caps are almost never the optimal solution to the trade-off between efficiency and rent extraction when there are firm budget or viability constraints and raise service quality issues."[39]

46. It is possible to find the same idea expressed in many other economic papers.[40] Other regulatory authorities in Australia have also expressed concerns at the use of high-powered incentives.[41]

47. Broadly speaking, an optimal regulatory regime will usually be neither very low powered, cost of service (or "rate of return") regulation, nor very high powered price cap (or "fixed price") regulation:

> Both "these two polar case regulatory mechanisms each have both positive and negative attributes. One is good at providing incentives for managerial efficiency and cost minimisation, but is bad at extracting the benefits of the lower costs for consumers. The other is good at rent extraction but leads to inefficiencies due to moral hazard resulting from suboptimal managerial effort. Perhaps not surprisingly, the optimal regulatory

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[38] Laffont and Tirole (2000), page 57-58: "A [low powered incentive] is … less sensitive than a [high-powered incentive] to the risk of regulatory capture by the regulated firm (at least when good accounting procedures are in place)". See also Beato and Laffont (2002), page 11.

[39] Joskow (2005), page 81.

[40] See, for example, Sappington (2000): "The drawbacks to [high powered incentives] are most pronounced when (1) there is considerable variation in possible costs; (2) the regulator values the consumers' surplus much more highly than profit; and (3) positive production levels are always desirable, but the regulated firm can choose not to operate with impunity. When factors (1) and (3) prevail, a regulator cannot avoid the possibility that the firm will earn considerable rent under [a high-powered incentive]. To induce the firm to operate when costs turn out to be relatively high despite the firm's best efforts to reduce costs, authorized prices cannot be too low. But relatively high prices will afford the firm considerable rent when realised costs are fortuitously low. Consequently, when factor (2) is also present [a high-powered incentive] may not be the best regulatory plan to implement", page 31.

[41] For example: PC (2001), page 349: "The [Productivity] Commission remains unconvinced that prices can be fully decoupled from costs". Farrier Swier (2002), page 17: "[An ideal regulatory regime would] aim to delink the prices set for an individual firm from its own costs … At the same time prices over time must be regulated at levels that are politically acceptable, and which ensure financial sustainability in the setting of regulated prices. Therefore, it would not seem possible to totally disregard actual costs in the long-term".

mechanism (in a second best sense) will lie somewhere between these two extremes. In general, it will have the form of a profit sharing contract or a sliding scale regulatory mechanism where the price that the regulated firm can charge is partially responsive to changes in realised costs and partially fixed ex ante".[42]

48. How then do we determine the power of the optimal regulatory contract? And what role does relative productivity information play in that contract? This is the question addressed in the next section.

What is the role for productivity information in the regulatory process?

49. The problem of information asymmetry lies at the heart of the problem faced by the regulator.[43] In the presence of the information asymmetry, there is a trade-off between the power of incentives and rent-extraction (in the "adverse selection" approach) and/or a trade-off between the power of incentives and risk (in the "principal-agent" approach). An improvement in the quality of the information available to the regulator reduces the severity of this trade-off, allowing the use of higher-powered incentives without undue risk or excess rent left to the regulated firm.

50. The regulator may still decide not to use a very high-powered incentive (perhaps because of a desire to maintain a balance with other incentives such as the incentive for service quality) but improving the quality of the information will ensure that for any given power of the incentive the harmful consequences of the trade-off are reduced. In general, more information is a good thing.

51. In this paper, I will try to illustrate the key results using a simple principal-agent model with certain special assumptions.[44] Like other models of regulation with asymmetric regulation, it is assumed that the cost out-turn of the regulated firm depends on both stochastic underlying cost-shifting factors and the effort of the management of the regulated firm to reduce the total expenditure of the regulated firm. It is assumed that the regulator cannot observe the managerial effort directly. Instead, the regulator can only observe the out-turn accounting cost of the regulated firm, which I will denote $\tilde{C}$. As already noted, this out-turn cost is a mix of "exogenous" or "uncontrollable" out-turn cost factors and the endogenous or controllable cost factors represented by the managerial effort.

52. The regulator would like to reward the management of the regulated firm for effort directed at reducing expenditure. But the regulator only has an imperfect signal of the actions of the regulated firm. The regulator therefore faces a classic information asymmetry problem.

53. The general principal-agent problem can be quite complex to solve. However, under certain assumptions[45] this problem becomes much simpler and significantly more intuitive.

[42] Joskow (2005), page 11

[43] "Asymmetric information plagues the relation between a regulator and monopoly (or monopolies) which he seeks to regulate. Notably, on the cost side, the regulator often has limited information on how efficient a firm is, or on how efficient a firm can be, even if most of the time he could observed realised costs". Chong (2004), page 3.

[44] This model is described in more detail in Biggar (2005b).

[45] Specifically, the optimal regulatory contract is linear when the regulated firm exhibits constant absolute risk aversion and the "error" in the signal observed by the regulator is normally distributed.

Biggar (2005b) sets out a number of principles of incentive regulation which can be easily illustrated using this framework.

54. For example, the "informativeness" principle says that if the regulator starts with some signal of the effort of the regulated firm, such as the observed cost out-turn $\tilde{C}$, and the regulator then observes another signal, which we might call $\tilde{Y}$, then the optimal regulatory contract will depend on $\tilde{Y}$ if and only if making use of this signal improves the precision with which the regulator can observe the (hidden) effort of the regulated firm.

55. In general, the "informativeness principle" states that when designing a regulatory contract the regulator should always factor into the regulatory contract any signal that improves the precision with which the regulator can observe the effort of the regulated firm (and, conversely, should exclude from the regulatory contract any signal which reduces the precision with which the regulator can measure the effort of the regulated firm).

56. The extent to which the optimal regulatory contract will depend on $\tilde{Y}$ depends on the extent to which $\tilde{Y}$ yields useful information about the effort of the regulated firm. If $\tilde{Y}$ is a very poor signal, the optimal regulatory contract will give little weight to the signal $\tilde{Y}$. Conversely, if $\tilde{Y}$ is a very good signal, the optimal regulatory contract will give significant weight to $\tilde{Y}$.

57. But, how exactly does information on the cost out-turns of other firms shed light on the effort exerted by the regulated firm? The answer depends on how costs vary across firms and over time. More precisely, the answer depends on the nature of the uncertainty in cost out-turns across firms and over time. For example:

(a) First, it may be that there is a group of firms which are all subject to the same "cost shocks" – that is, a change in technology, or input costs, or weather, affect all of these firms in the same way. In this case, information on the performance of other firms can assist the regulator in separating out changes in costs which are due to exogenous factors from changes in costs which are due to endogenous factors (that is, the effort exerted by the regulated firm). In this case it is the *level* of observed cost out-turns of other firms which are important. As we will see below, this information is then used to create a regulatory contract under which the regulated firm is rewarded in part for its relative performance. This is also known as "benchmarking" or "yardstick regulation".

(b) Second, it may be that firms are subject to different cost shocks but the underlying *rate of change* of the cost over time is the same across a group of firms. In this case, information on the trends in the cost out-turn of other firms might be useful to the regulator in separating out that change in the cost out-turn which is due to effort by the regulated firm and that change in the cost out-turn which is due to on-going exogenous technology changes.

58. More generally, the way that productivity information is best used (and ultimately the design of the optimal regulatory mechanism) depends on the nature of the uncertainty faced by the regulator and the nature of the information that can be obtained by an examination of the performance of comparator firms.

59. Let's consider the case where there is a group of firms which are all subject to common exogenous shocks to their cost out-turns. Suppose that the regulator is attempting to create incentives on firm 1 to reduce its cost and can observe the cost out-turn of firm 1, denoted $\tilde{C}_1$. Suppose that there is another firm which is exposed to many of the same cost "shocks" as firm 1, with an observed cost out-turn $\tilde{C}_2$. As we will see, since observing the cost out-turn $\tilde{C}_2$ allows the regulator to increase the precision with which it observes the effort of firm 1, the optimal regulatory contract for firm 1 should also depend on the cost out-turn for firm 2, $\tilde{C}_2$.

60. But how exactly should the optimal regulatory contract for firm 1 depends on the cost out-turn for firm 2? It turns out that under certain circumstances (the "linearity" principle[46]) the optimal contract is linear in the two cost out-turns, so the optimal regulatory contract takes the form: $\pi(\tilde{C}_1, \tilde{C}_2) = A - B(\tilde{C}_1 - D\tilde{C}_2)$.

61. For our purposes, the interesting point is that we can re-write the optimal contract in the following way: $\pi(\tilde{C}_1, \tilde{C}_2) = A - B((1-D)\tilde{C}_1 + D(\tilde{C}_1 - \tilde{C}_2))$.Written in this way it is clear that the optimal regulatory contract should include elements of both *relative* and *absolute* performance evaluation. That is, under the optimal regulatory contract the regulated firm should be both rewarded for reducing its own costs $\tilde{C}_1$ and also further rewarded for the difference between its own costs and that of a comparable firm $\tilde{C}_1 - \tilde{C}_2$.

62. The relative weight given to *relative* versus *absolute* performance evaluation depends on the level of parameter *D*. If *D* is very small, very little weight should be given to relative performance evaluation. If *D* is close to one, virtually exclusive weight should be given to the relative performance of the firm. It turns out that the optimal choice of *D* is given by the expression: $D = \dfrac{\operatorname{cov}(\tilde{C}_1, \tilde{C}_2)}{\operatorname{var}(\tilde{C}_2)}$. Therefore the weight given to relative performance evaluation depends on the correlation of the cost out-turns of the two firms.

63. Suppose that both firm 1 and firm 2 have a cost out-turn which is equal to a common underlying cost-shifting factor plus an error term – i.e., $\tilde{C}_1 = \tilde{C} + \tilde{\varepsilon}_1 - e_1$ and $\tilde{C}_2 = \tilde{C} + \tilde{\varepsilon}_2 - e_2$ where $\tilde{\varepsilon}_1$ and $\tilde{\varepsilon}_2$ are independently distributed random shocks and e_1 and e_2 is the (hidden) managerial effort of the two firms. In this case $D = \dfrac{\sigma_C^2}{\sigma_C^2 + \sigma_\varepsilon^2}$. In other words, the optimal weight given to relative performance evaluation depends on the magnitude of the variability of the common cost-shifting factors relative to the variability of the firm-specific idiosyncratic factor. If it is the case that 90% of the observed variability in costs is due to the common cost-shifting factors, then the optimal regulatory contract should give a 90% weight to relative performance evaluation.

[46] See Biggar (2005b)

64. On the other hand, if the common cost-shifting factors account for only a small percentage of the observed variability in cost out-turns then relative performance evaluation should be given only relatively little weight in the optimal regulatory contract. In the extreme case in which firm's cost out-turns are completely uncorrelated there is no role for relative performance evaluation in the optimal contract. "It is valueless to reward agents according to their relative performance if there is no common underlying uncertainty".[47]

65. In the case where there is some common underlying cost-shifting factor, the use of the comparator term $\tilde{C}_1 - \tilde{C}_2$ in the regulatory contract reduces the variance of the regulator's overall signal of the firm's effort. As a result, the optimal power of the incentive mechanism (represented by *B* in the equation above) is now somewhat higher. This is just an application of the "incentive-intensity" principle[48] – the greater the precision of the signal of the regulator, the higher the power of the optimal incentive mechanism.

66. In fact, in this example, adding the comparator information reduced the overall variance of the signal by the factor $1-D$. So, when *D* is large (that is, when the variance in the common cost-shifting factors accounts for a large proportion of the total variance of the cost out-turn of a firm), the regulator gains a lot of information by including a comparator firm in the regulatory contract and the optimal power of the incentive mechanism will increase significantly.[49] Conversely when the firm-specific cost factors account for a large fraction of the observed variability in cost out-turns, the information value from adding a comparator firm to the regulatory contract is slight and will have relatively little impact on the power of the optimal incentive mechanism.

67. The example above assumed that there was only one comparator firm. Of course, the same sort of analysis can be applied in the case where there are a number of comparator firms. If we suppose that we have a number of firms indexed by $i = 1,\ldots,N$ whose cost function is given by $\tilde{C}_i = \tilde{C} + \tilde{\varepsilon}_i - e_i$ where the $\tilde{\varepsilon}_i$ are independently and identically distributed, then it turns out that the optimal regulatory contract takes the form:

$$\pi = A - B((1-\alpha_N)\tilde{C}_0 + \alpha_N(\tilde{C}_0 - \sum_i \tilde{C}_i / N)) \text{ where } \alpha_N = \frac{N\sigma_C^2}{N\sigma_C^2 + \sigma_\varepsilon^2}$$

68. In other words, in this simplified case:

[47] Chong (2004), page 7. Chong (2004) also points out that there may be value in relative performance evaluation even if there is no common underlying source of uncertainty – this might arise when one firm can observe the effort of another firm and the performance of one firm affects the performance of the other. In this case the regulator can use the regulatory contract to induce one firm to "police" the actions of the other. However this circumstance seems to me to be too unlikely in the context of regulation. In particular, it seems unlikely that regulated firms, operating in different areas, will be better able to observe the cost-reducing effort of other firms any better than the regulator.

[48] See Biggar (2005b).

[49] It is worth noting that in the case where *D* is close to 1 and the optimal power of the incentive *B* is also close to one, the regulated revenue stream of the regulated firm depends only on the cost out-turn of the *other* firm in the industry.

(a) the optimal regulatory contract involves rewarding the regulated firm for the difference between its own cost out-turn and the *average* cost out-turn for the other comparable firms; and

(b) the weighting given to relative performance evaluation increases in the number of comparator firms. If the number of comparator firms is large enough *exclusive* weight is given to relative performance evaluation.

69. As before, the greater the number of comparator firms the greater the precision with which the regulator can observe the effort of the regulated firm and therefore (a) the greater the weight given to relative performance evaluation and (b) the greater the optimal power of the overall incentive.

70. Laffont and Tirole (2000) summarise the use of relative performance evaluation as follows:

> "Benchmarking (or 'yardstick competition' or 'relative performance evaluation') consists in comparing the performance of the firm with that of other firms facing a related (technically: correlated) situation. For example, other firms might produce the same public good in different geographical areas. To the extent that the technologies used to produce in different areas are similar, one can compare the performances of these other firms to gather relevant information about the firm one is regulating. In particular, the government becomes suspicious if its contractor announces and produces at a very high cost while the supplier in a neighbouring area produces at a low cost. The comparison of performances of producers facing similar technological conditions thus reduces the asymmetry of information and enables the use of higher-powered incentive schemes". [50]

Using information on productivity trends in the regulatory process

71. The example above focused on the case where firms had the same "underlying" cost but were subject to firm-specific independent cost shocks, so that there was a degree of correlation of firm cost levels over time. However, in practice, there has been a lot of focus on the use of productivity information to determine *rates of change* of cost/productivity information over time. Under what conditions might it be appropriate to focus on rates of change of productivity information?

72. Suppose that all comparator firms were subject to the same, unknown, change in the underlying cost from one year to the next. The observed change in cost from one year to the next would then be equal to this constant underlying rate of "productivity improvement" plus firm-specific independent cost shocks plus any changes in the level of effort exerted by the firm from one period to the next.

73. In this context, the key problem faced by the regulator is disentangling changes in costs due to changes in the effort of the regulated firm from changes in costs due to the underlying exogenous rate of productivity improvement. If the firm were myopic the regulator could simply hold the power of the incentive mechanism fixed for a few years and observe the resulting rate of change in costs (if the power of the incentive mechanism is fixed, the effort level chosen by the firm will be fixed, and any resulting change in costs will be due to the exogenous productivity

[50] Laffont and Tirole (2000), page 52.

improvement alone). In practice, however, the firm is likely to realise that the regulator will use the observed rate of cost improvement to set revenue targets in the future and will therefore act strategically to ensure that the rate of cost improvement is lower than the underlying rate.

74. In principle, it would nevertheless be possible to design a regulatory regime which over time allowed the regulator to infer the constant rate of productivity improvement and therefore to offer higher-powered incentives. Without carrying out the analysis, my hypothesis is that the optimal regulatory mechanism would involve a series of regulatory contracts of increasing power over time, as more information is learned about the fixed rate of change of efficiency.

The use of productivity information in practice

75. The previous section emphasised that the way that productivity information is best used in the regulatory process – and the design of the optimal regulatory contract – depends on the nature of the uncertainty faced by the regulator and the nature of the information that can be obtained by an examination of the performance of comparator firms.

76. In practice, productivity information has often been used in regulatory processes in a mechanistic manner with little explicit consideration of how much information can be obtained from productivity comparison and how that information is best extracted. For example, regulators have, on occasion, used productivity information in the following manner:

(a) First, information on inputs and outputs of a number of different firms is measured and collected.

(b) Second, this information is then normalised using one of the common statistical techniques (such as DEA, SFA, COLS, and so on). The firms are then ranked according to their relative efficiency/productivity.

(c) Third, it is assumed that all of the difference between firms is attributable to controllable cost efficiencies (or, in the language used in this paper, the effort exerted by the regulated firm). The allowed revenue of each firm is then set on the basis of the most efficient firm. This might be either through a P0 adjustment, or, more likely, by adjusting the X factor so that firms which are deemed to be relative less efficient are given a larger X factor to bring them down to the "efficient frontier" over the course of the regulatory period.

77. This is the approach that was used, for example, in the Netherlands, in a process which has been described as having "gone badly wrong"[51] Specifically, in the Netherlands, a DEA technique was used to determine the relative efficiencies of different companies. The X factor was then set at a level which would bring the annual revenue of each company down to the "efficient" level over the course of a three-year regulatory period. This led to X factors which, for some companies were as high as 8%. The inevitable appeals led to several revisions to the X factors and substantial delays. The main result has been the politicisation of the debate around liberalisation and privatisation in the Netherlands.

[51] See Nillesen and Pollitt (2004).

78. The question which I would like to address is the following: Are there conditions under which this approach would make sense? What do we have to assume about the information that can be obtained from relative productivity data for the Dutch approach to make sense? Are those assumptions reasonable?

79. Let's assume for the moment that it is possible to effectively "normalise" the input/output information from each firm so as to obtain an accurate reflection of each firm's relative efficiency. In the next section I will show that this assumption is highly questionable. However, for the moment let's simply assume that the ranking of the efficiency of firms is accurate. Should the allowed revenue be set on the basis of the observed cost of the most efficiency firm? As we will see, this might be an optimal arrangement, but only if there were no firm-specific factors which affect the cost out-turns of different firms differently.

80. Recall that in the earlier analysis where there were two identical firms, the optimal regulatory contract took the form $\pi(\tilde{C}_1, \tilde{C}_2) = A - B((1-D)\tilde{C}_1 + D(\tilde{C}_1 - \tilde{C}_2))$. In the case where there are no firm-specific cost shocks (that is where the observed cost of each firm is equal to a common underlying cost less the effort exerted by management to reduce costs: $\tilde{C}_1 = \tilde{C} - e_1$ and $\tilde{C}_2 = \tilde{C} - e_2$), the difference in observed cost out-turns is due only to differences in the effort exerted by management of the two firms. In this case the optimal weight given to relative performance evaluation is 100%. Since there is no "noise" in the signal of the effort of the regulated firm, the optimal power of the incentive is 100%.

81. In other words, the optimal regulatory contract in this case is $\pi(\tilde{C}_1, \tilde{C}_2) = A - \tilde{C}_1 + \tilde{C}_2$. But since the profit of the regulated firm is equal to its revenue less its cost out-turn $\tilde{C}_1$, this implies that under the optimal regulatory contract the regulator should simply give each firm revenue equal to the cost out-turn of the other firm. In equilibrium each firm chooses an efficient level of effort and is fully compensated for the resulting costs.

82. This analysis clearly generalises to the case of multiple identical firms. In this case an optimal regulatory contract is to set the revenue of each regulated firm equal to the lowest observed cost out-turn of the other regulated firms.[52] In equilibrium each firm chooses an efficient level of effort, reveals the same out-turn cost and is fully compensated.

83. So we have shown that it *might* be theoretically appropriate to set a revenue target on the basis of the most efficient comparator firm. However it is important to emphasise just how particular the assumptions of this model are. Most importantly we have assumed that *all* of the difference in the performance of two firms is due to differences in the effort to reduce costs. In effect this implies that we can observe and have fully controlled for all the exogenous drivers of cost. These assumptions are unrealistic.

84. In practice, the observed differences in the relative efficiencies of different firms will depend on a variety of factors such as a failure to control for various observable factors and a variety of unobservable factors. If we observe that firm A is less efficient than firm B this could be due to the failure to adequately control for differences in the cost drivers of firm A and firm B

[52] This result goes back to Shleifer's original paper on yardstick competition - Shleifer (1985). He showed that the prices could be set on the basis of any function of the cost out-turns of other firms which satisfied certain minimal conditions.

(for example, a failure to adequately take into account the differences between rural and urban firms) or due to random differences which are no fault of the management of firm A and firm B (such as differences in the weather to which the two firms were exposed). As Shuttleworth (1999) notes:

> "If a DEA model gives a company a score of 90%, all one can really say is that the model has failed to explain 10% of the company's costs. Whether this 10% of costs is due to inefficiency is only a matter of opinion".[53]

85. Setting the revenue of a regulated company on the basis of the most efficient of its peers in effect assumes a particular form of the structure of the uncertainty in the underlying cost. This structure is unlikely to arise in practice. This approach is therefore questionable. With hindsight it is not surprising that the Dutch regulator ran into difficulties.[54]

86. In the recent distribution price control review in the UK several distribution companies argued that Ofgem's use of a frontier technique was unnecessary and that benchmarking to the average performance would be more appropriate.[55] The analysis above shows that benchmarking to the average performance makes sense when differences in the observed efficiencies of firms are in part due to a firm-specific random cost shock. In this case the analysis above shows that the optimal regulatory contract should not give 100% weight to the relative efficiency of the regulated firm – that is, the under the optimal regulatory contract the firm's revenue should depend on both its own observed cost and on its relative performance compared to the average of other firms.

87. To repeat the point made earlier, the way that productivity information is best used – and ultimately the design of the optimal regulatory contract – depends on the nature of the uncertainty faced by the regulator and the nature of the information that can be obtained by an examination of the performance of comparator firms.

What exactly can be learned from relative productivity information?

88. But this raises the question: What exactly is the nature of the information that can be obtained by examining the performance of other firms? Unfortunately, at this point there seems to be a large gap in regulatory knowledge.[56] There are a few papers which, from a theoretical perspective show that if the structure of the uncertainty in the productivity of firms takes the form X, then the optimal form of the regulatory mechanism is Y.[57] But there are no papers which seek to examine empirically the structure of the uncertainty across firms.

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[53] Shuttleworth (2003), page 5.

[54] Nillesen and Pollitt (2004) point out that the Dutch regulator used relative efficiencies to set revenue directly despite the fact that "The efficiency scores were not cross-checked with other methods, neither were the companies grouped into different categories, such as for example top performers, average, and poor performers, thus making no allowance for stochastic factors … measurement error or misspecification of inputs and outputs. Secondly, the DTe applied the efficiency scores to total cost (including capital costs …) as opposed to just operational expenditure as it had been discussing with the sector", page 15-16.

[55] See Ofgem (2004), "Electricity Distribution Price Control Review: Summary of Responses to June 2004 Initial Proposals" September 2004.

[56] "While the theoretical literature on incentive regulation is quite rich, it still provides relatively little direct guidance for empirical application in specific circumstances. Regulators need to find answers to a number of practical questions to apply the theory in practice in the design of actual incentive mechanisms". Joskow (2005), page 25.

[57] See, for example, the papers by Choné and Lesur (2001) and Tangeras (2002).

89. Specifically, we would like answers to the following questions:

- First, is there any evidence that the cost out-turns of different firms are correlated at all? Or are they subject to largely independent forces?

- If they are correlated, are they correlated across time or across different firms? Does this correlation depend on the technique used for assessing relative efficiency?

- Are their groups of firms which tend to be more closely correlated (such as rural versus urban firms, large versus small firms)?

- Are some components of cost (such as operating expenditure) more closely correlated than other components of cost (such as capital expenditure)?

- What part of the variation in the cost performance of firms can be explained through exogenous factors such as labour rates, exchange rates, or input costs?

90. One of the key recommendations below is to investigate further the nature of the information that can be obtained from relative productivity information.

Practical issues in the use of relative productivity information

91. In the previous sections we noted that, in principle, the use of relative productivity information by the regulator can "reduce its information disadvantage, allowing it to use high-powered incentive mechanisms without incurring the cost of excessive rents"[58]. But there are several practice issues which I will examine in turn:

(a) Problems relating to the handling of capital expenditure;

(b) The need to acknowledge uncertainty and error in the benchmarking process itself;

(c) The problem of collusion and incentives to merge;

Handling of capital expenditure

92. Virtually all regulated firms must make substantial investments in sunk long-lived assets. The cost of servicing these investments may comprise a significant portion of the total annual revenue requirement. Usually, some attempt is made to smooth the expenditure of capital assets over the life of the assets. Ideally the smoothed (or "amortised") capital expenditure would, somehow, reflect in each year an annualised cost for the services of the stock of existing capital. A comparison of the costs incurred by different firms in any given year would then somehow reflect the total (capital and operating) services consumed in that year.

[58] Joskow (2005), page 23.

93. Unfortunately, the allocation of the total cost of sunk assets to any one period of the life of the assets is entirely arbitrary.[59] This arbitrariness gives rise to a well-known regulatory problem – the inability of the regulator to assess the profitability of the regulated entity through a comparison of its total revenue and total "costs" in any one year – since the allocation of the total costs of sunk assets is arbitrary the relationship between the firm's revenue and its "costs" in any one year says nothing about whether or not the firm is profitable overall. To assess whether or not the firm is profitable overall requires a comparison of the revenue stream and the cost stream of the firm over the life of the firm.

94. This same problem of sunk-cost allocation also naturally arises when we are attempting to compare the "costs" of two different firms. Since the allocation of the sunk costs of each firm to any one year is arbitrary, a comparison of their annualised costs in one year is meaningless. We can only obtain a meaningful comparison of their costs over the life of the relevant firms.

95. In practice this problem is addressed by making an arbitrary decision as to how these sunk costs will be allocated – for example, by assuming straight-line depreciation. But there is no reason why any one methodology for allocating these costs is necessarily preferred over any other. A shift from straight-line depreciation to some other form of depreciation might significantly affect the apparent relative costs of two firms.[60] This issue should, at a minimum, introduce a tone of caution into any approach based on inter-firm comparisons of total (annualised) costs.

96. One way around this problem might be to argue that we only need to be concerned about *new* capital expenditure. Past capital expenditure is sunk and cannot be affected by the current incentive regime. The current incentive regime can only impact on current investment. On this basis it might be argued that, rather than focus on comparing the annualised cost of the *stock* of capital, we should focus on comparing the cost of capital *flows* – that is, new investment.

97. The problem with this approach is that investment expenditure is notoriously volatile and relatively uncorrelated across firms. As noted in Biggar (2005a), much investment expenditure is "non-recurring", implying that past expenditure levels by the same company provide relative little guidance as to likely future levels. For the same reason, expenditure levels by other companies provide relative little guidance as to the likely needed investment by the regulated firm in question. Joskow (2005) writes:

> "Formal statistical benchmarking studies of the type that are now applied to operating costs … have not been applied to determine allowed investment costs over the next price cap period for [any UK] electric distribution company. The appropriate investment

[59] More precisely, the "correct" way to allocate these costs would involve consideration of the impact of the allocation on the demand side of the market.

[60] Diewert and Lawrence (2004), page 4, explain this as follows: "When a firm purchases a durable capital input, it is not appropriate to allocate the entire purchase price as a cost to the initial period when the asset was purchased. It is necessary to distribute this initial purchase cost across the useful life of the asset. … This means that for productivity measurement purposes, the regulator will have to manipulate accounting data in order to construct user costs for capital components. These user costs are made up of three components: depreciation, interest tied up and anticipated asset price change. However, each of these components pose practical measurement problems". CEPA (2003) argue that: "Although ideally benchmarking should apply to total costs rather than individual components, in practice, this is difficult to implement due to the heterogenous nature of capital and the difficulties in measuring capital expenditure accurately and consistently". In fact, it is no more difficult to measure capital expenditure than it is to measure operating expenditure. Presumably CEPA mean that it is difficult to determine an annualised (amortised) capital cost accurately and consistently.

program may vary widely depending on variables like customer growth rates, load growth rates, equipment ages and replacement expenditures, underground versus above ground facilities, service quality improvement needs, etc. with little necessary relationship to recent historical trends. Indeed, the rate of investment in electricity network infrastructure has historically been quite cyclical. As a result it has proven difficult to develop useful statistical benchmarks for future capital additions".[61]

98. Given these difficulties with inter-firm comparison of capital expenditure or total expenditure, many regulators have chosen to focus only on comparisons of operating expenditure.[62] This has at least two drawbacks – First, a firm may appear to be more or less efficient simply because it has chosen a different point of substitution between capital and operating costs. Second, this focus on operating expenditure will easily lead to a different power of incentive to reduce operating compared to capital expenditure. This will induce the regulated firm to substitute capex for opex or vice versa. CEPA (2003):

> "On one level, such gaming may simply manifest itself in changes in company accounting policies, resulting in additional audit work for the regulator in 'cleaning' the data to make the data comparable across companies. In more extreme cases the substitution effect may be real in that a company moves away from its optimal input mix. The inefficiencies associated with such substitution will remain for the full lives of the assets concerned".[63]

99. At present there is no easy answer to this problem. Inter-firm comparisons of annualised costs should be treated with caution.

Uncertainty and error in the benchmarking process

100. A second significant obstacle to the use of relative productivity information concerns the uncertainty and error in the benchmarking process itself. There are several potential sources of error and uncertainty:

(a) First, as discussed below, different approaches to measuring productivity or efficiency are based on different assumptions and often yield different results.

(b) Second, there are often data limitations which limit the extent to which the regulator can accurately capture the key input and output cost-drivers. The selection of inputs and outputs to use is therefore another potential source of error.

(c) Third, there may arise problems in measuring or aggregating certain key inputs – such as labour costs (how is the labour input of the CEO to be valued relative to the labour input of, say, a salesperson?).

[61] Joskow (2005), page 42.

[62] "Although it is not discussed too much in the empirical literature, the development of the parameters of price-cap mechanisms using statistical benchmarking methods have typically focused primarily on operating costs only, with capital cost allowances established through more traditional utility planning and cost of service regulatory accounting methods including the specification of a regulatory asset base (RAB), depreciation rates, debt and equity costs, debt/equity ratios, tax allowances, etc." Joskow (2005), page 36-37. See for example Ofgem in 1999.

[63] CEPA (2003), page 84.

(d) Fourth, as we have seen above, there is uncertainty over exactly how the relative productivity information sheds light on the managerial effort of the regulated firm.

101. First, let's discuss issues in choosing a methodology to standardise or normalise the input-output data for different firms to account for the fact that different firms costs vary due to differences in their cost drivers, such as differences in the quantity and quality of their outputs (or differences in other factors such as weather, geography or terrain).

102. There are a variety of statistical and non-statistical techniques for normalising the cost functions of firms, including different forms of total factor productivity indices, data envelopment analysis, statistical frontier analysis, ordinary least squares regression (and so-called "corrected ordinary least squares). The paper by CEPA (2003) prepared for Ofgem is a useful survey.[64]

103. Economic theory provides very little guidance as to which is the best approach to use. This would not be a problem if different approaches yielded very similar results, but this is not the case. A number of papers have demonstrated that the ranking of the apparent efficiency of different firms is very sensitive to the choice of methodology. For example, Farsi and Filippini (2005) in a comparison of different techniques for measuring the efficiency of electricity distribution utilities in Switzerland conclude that their results:

> "… illustrate a main problem in benchmarking analysis, that is the discrepancy of the results across different methods. In some cases, the sensitivity of efficiency estimates is so high that a slight change in the model's assumptions or including an additional variable might change the results considerably. Given the extremely large variety of models and specifications, this problem does not appear to have a clear solution".[65]

104. A paper by Bauer et al (1997) sets out a list of often-cited criteria which a good benchmarking methodology must satisfy. Amongst their criteria is the criterion of "robustness". That is, "the model selected must be robust to changes in assumptions and methodologies. In particular, the ranking of firms, especially with respect to the 'best' and worst' performers, and the results over time should demonstrate reasonably stability; and the different approaches should have comparable means, standard deviations and distributional properties".[66] Farsi and Filippini (2005) note that these criteria "are far from satisfied".

105. One of the primary reasons why different approaches yield different results is that the researchers are often limited to only relatively small numbers of companies and relatively small data sets, with simple definitions of inputs and outputs. Where key cost drivers are omitted firms may appear relatively more or less efficient than they are.

106. Most relative productivity studies use only a very small number of input and output variables. For example, the 2005 Farsi and Filippini study used a single output and three inputs. The 1999 study by Ofgem used one output and an input which was a composite of three variables.[67] Over time, as larger data sets are compiled – with both more data over time and a

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[64] See also Farsi et al (2005)
[65] Farsi and Filippini (2005), page 12-13.
[66] CEPA (2003), page 10.
[67] A table by Farsi et al (2005) shows that the number of inputs assumed varies between 3 and 6 in different studies (page 14).

larger number of companies, it may be possible to better capture the key cost drivers of these firms and therefore to obtain more reliable results.[68]

107. However, even with more data and a broader definition of the cost drivers affecting different firms it is unlikely that these models will ever be able to control for all of the different exogenous factors affecting firm's costs perfectly.

108. Even where the regulator is able to measure the most-important cost drivers, problems can arise in the measurement process itself. For example, should labour input be measured by the number of employees? What if a company has a large number of part-time workers? Or often relies on sub-contractors? Diewert and Lawrence (2004) in a paper for the ACCC emphasise that these measurement problems should not be underestimated:

> "It can be seen that there will generally be significant measurement problems associated with the implementation of a form of incentive regulation that requires information on either the productivity or the unit costs of the regulated firms. In fact, the list of measurement difficulties seems quite formidable that one might wonder if incentive regulation is worthwhile. Our view is that it is worthwhile but one must be aware of the measurement pitfalls. … One should work with the imperfect data that are available, while at the same time, making practical efforts to improve the data quality".[69]

109. Finally, even if we could measure all of the important cost drivers of these firms accurately and even if we could use that information to correctly assess the relative efficiency of firms, there remains uncertainty about the nature of the cost shocks which affect these firms. What is the best way to statistically model these shocks? Are they correlated over time or across firms?

110. In summary, there are at least four sources of potential error and uncertainty in the use of productivity information. Errors in the assumptions of the technique used to normalise the data (that is, the DEA, TFP, SFA technique); errors in the selection of measured inputs and outputs (in particular, failing to correctly include relevant inputs or outputs); errors in the measurement or aggregation of the inputs or outputs; and errors in the assumptions about the information that can be obtained from relative productivity information and how that information is best extracted.

111. Regulators must therefore not be over-optimistic as to the value of the information that can be obtained through these models, recognising that considerable uncertainty remains as to the reasons for the observed differences in efficiencies of firms. The information that can be obtained from these models about the effort exerted by management to reduce expenditure will likely be limited, at least at the outset. As we have seen above, this has direct implications as to how the productivity information should be used in the optimal regulatory contract.

The problem of collusion and incentives to merge

112. The final issue or obstacle to the use of relative productivity information in regulation relates to some of the adverse incentives that are thereby created. Let's suppose that it is, in fact, possible to make effective comparisons of the performance of different firms and to develop an

[68] CEPA recommend to Ofgem the use of time series data and the inclusion of data on companies in other countries.
[69] Diewert and Lawrence (2004), page 12.

incentive mechanism based on these performance comparisons. If the revenue of the firms in a regulated industry depends on the relative performance of these firms there may arise certain adverse incentives.

113. For example, as we have already seen, if (due to the difficulties of measuring capex in a systematic way) the regulatory regime focuses on opex incentives, there may arise incentives to inefficiently substitute between capex and opex. In addition, since the relative productivity performance of a given firm is likely to depend on the methodology used, or the "weights" attached to different inputs and outputs in, say, a DEA approach, the firms will have strong incentives to influence the regulator to adopt one or other methodology, or to alter the weights in various ways.[70]

114. Furthermore, there may arise incentives for firms to enter into collusive arrangements or to merge. Consider for example the simplest form of yardstick competition with two identical firms in which the revenue allowed to one firm is equal to the cost out-turn of the other firm. In this case if the two firms could simply agree to not compete to lower their costs they could enjoy high revenues without the need to exert effort to keep their costs down. Shleifer (1985) in his original paper on yardstick competition writes: "An important potential limitation of yardstick competition is its susceptibility to collusive manipulation by participating firms"[71] but if the number of regulated firms is large "complicated collusive strategies may not be sustainable". It may be possible to alter the regulatory contract in order to make collusion unprofitable.[72]

115. The same incentives to collude may also give rise to an incentive to merge. If the firms are local monopolies, a merger would have no impact on competition as traditionally assessed but would, under yardstick competition, have an impact on the quality of the regulation. This may create difficulties for competition authorities seeking to block further consolidation. Jamasb et al (2004) note that:

> "Mergers and acquisitions involve two sources of concern for regulators that use benchmarking: (i) transactions intended to influence the relative position of the firm without achieving real efficiency gains and (ii) the shrinking number of firms and reduction in information on which regulates base their analysis".[73]

116. These incentives to collude or merge might not only arise in an industry with a small number of players. For example, under the DEA methodology one firm may define the

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[70] See, for example, Jamasb et al (2004), page 838.

[71] Shleifer (1985), page 327.

[72] Chong (2004) page 20: "Laffont and Martimort (2000) argue that the regulator should introduce collusion-proof constraints to discourage firms from playing co-operative strategies. Such constraints lead to distortion in productive efficiencies in order to reduce the cost of collusion-proof constraints and deliver a 'third-best' equilibrium". Potters et al (2003) conduct an experimental test of collusion under yardstick competition with a duopoly. They confirm that collusion may occur and find that a scheme in which both players are given revenue equal to the average of the cost out-turn of the two firms is less prone to collusion than the scheme in which each firm is given revenue equal to the out-turn of the other firm.

[73] Jamasb (2004), page 839. Oxera notes: "As the water industry has consolidated, the number of comparators in both water and sewerage has fallen. This has made comparisons between companies by Ofwat more difficult as there are fewer independent management styles to generate innovation at the frontier. The regulator's response has been not only to place a value on each comparator, but also to consider extensions to its modelling approach, such as using sub-company-level data in sewerage, considering the use of data over time, and sense-checking results using a variety of modelling techniques to ensure consistency". Oxera (2005), page 3.

performance frontier for all the other firms, no matter how many firms there are in the industry. An agreement or merger between that firm and another firm could have the effect of increasing the efficiency scores (and potentially the revenue) of all the other firms.

What if collecting and processing information is costly?

117. The previous section put to one side the cost of collecting and processing information. There we saw that it will almost always be useful to include productivity information in the optimal regulatory contract. The weighting given to relative productivity information depends on the informativeness of the productivity information which depends, in turn, on the extent to which firms' costs are correlated and the number of firms.

118. But what if collecting and processing information is costly? When should we rely on productivity information and when should we rely on firm-specific information? or both?

119. Whether or not it is worth collecting a given piece of information depends, of course, on the extent to which that information improves the overall welfare outcome – that is, the extent to which the information reduces the severity of the trade-off between the power of incentives and risk or rent-extraction.

120. Consider first the policy of relying solely on firm-specific cost information. This information tends to be rather costly to collect – as the volume of material is large and the information must be audited and verified through a time-consuming and resource-intensive process. The cost of collecting and processing this information is roughly proportional to the number and size of the regulated firms – if the number of regulated firms doubles (with no major change in the average size of firms) we would expect the cost of collecting and processing this information would also double. At the same time, we would expect that the welfare gains from having this information also roughly doubles – in other words, as the number of firms under the responsibility of the regulator increases, we might expect that the net welfare from collecting and processing firm-specific cost information would increase roughly in proportion to the number of firms.

121. The situation is quite different for relative productivity information. The quantity of information to be collected is significantly smaller and more easily verified. There are fixed costs in setting up the methodology, but once the methodology has been set up the cost of regulating an additional firm is relatively small. When the number of comparator firms is small, however, the information obtained from relative performance evaluation is limited. In this case this approach is unreliable and will not yield welfare gains as high as under the firm-specific cost approach. As the number of firms increases the reliability of this approach increases.

122. This argument suggests that the choice between reliance on relative productivity information and firm-specific information depends in part on the number of regulated firms in the industry. If there are only one or two regulated firms in the industry, the information value of relative performance evaluation is likely to be relatively small and the methodology would be costly to set up. In this case it may be preferable to rely exclusively on firm-specific cost information.[74] On the other hand, if there are many firms (say more than ten) in the industry, the

[74] This is the case in, for example, electricity transmission: "Statistical benchmarking is very difficult for transmission networks. There is only one transmission network in England and Wales. The composition of a particular transmission network depends on many variables, including the distribution of generators and

information value of relative performance evaluation could be quite high and the cost significantly less than the cost of collecting and processing firm-specific cost information for every firm. In this case, it may be preferable to rely exclusively on relative performance information. There may also be a range of firms for which it is optimal for both approaches to be used simultaneously.

123. For example, suppose that it costs $1 million to conduct a thorough audit of the firm-specific cost claims for each regulated firm. At the same time, suppose that there is a fixed cost of $4 million to conduct a thorough "benchmarking" analysis for five firms, with this cost increasing by $100,000 for each additional firm. Under these assumptions it is clear that on a cost-of-regulation information alone, it is cheaper to carry out the benchmarking analysis when there are five or more firms in the industry. A full analysis would require consideration of the value of the information revealed under each approach.

124. This analysis is only suggestive. But, intuitively it seems likely that the use of relative productivity information becomes significantly more attractive as the number of regulated firms increases.

125. Note that this analysis also suggests a reason why it is sensible to aggregate and centralise the responsibilities of regulatory agencies. If there are *N* firms to be regulated what is the optimal number, *M*, of regulators? While having more regulators increases the range and diversity of regulatory approaches, and therefore the number of simultaneous "natural experiments" in different forms of regulation, this analysis suggests it also has some costs. The larger the number of regulators the more likely it is that differences in outcomes across firms is due to differences in regulatory regime rather than differences inherent in the firms – this reduces the information content of relative productivity information. Similarly, if there are transactions costs across regulators, the larger the number of regulators the more likely it is that each regulator will choose to adopt a firm-specific cost approach even though it would be more efficient, across the country as a whole, to rely exclusively on relative productivity information.

Recommendations and conclusions

126. There have been varying degrees of enthusiasm for the use of productivity-based regulation amongst regulators in Australia. This variation could be due to either misleading claims by advocates of productivity-based regulation (over, say, the desirability of high-powered incentives) or due to variations in the information value and/or the cost of obtaining productivity information across different industries or sectors.

127. Whatever the role for productivity information, regulators must ensure that they establish a regulatory regime which maintains a balance between the different desirable incentives (such as incentives for productive efficiency, incentives for investment and incentives for maintaining

load, population density, geographic topography, the attributes and age of the legacy network's components and various environmental constraints affecting siting of new lines, transformers and substations. Compatible cost and performance data are also not collected across transmission networks. Indeed there is no standardisation of where transmission networks end and the distribution network begins. In the UK, the transmission network includes network elements that operate at 270 kV and above … Accordingly opportunities for relying on statistical benchmarking are not yet available and the value of X is determined through a regulatory consultation process rather than through statistical benchmarking studies". Joskow (2005), page 64.

quality).[75] Since the incentive properties of a regulatory regime depend in part on what the regulator will do in the future (at the end of the current regulatory period) it is desirable for regulators to be clear about their future policies and to stick to these policies when the end of the regulatory period arrives. The relative importance of incentives for productive efficiency and for maintaining service quality will vary from sector to sector. As a result, even in the absence of a possible role for relative productivity information, it is unlikely that there is a single optimal regulatory regime for all sectors.

128. As we have seen in this paper, the collection and processing of information is part of the core business of a regulator. In general relative productivity information collected from comparator firms will yield at least some useful information. In most cases the information necessary to compare productivity across firms is not too onerous or costly to collect or verify. As Joskow (2005) notes:

> "Collection of data on all relevant and significant measures of firm performance and the use of this data for benchmarking purposes and for developing performance targets is an important component of good incentive regulation in practice. Regulators need the authority to require firms to collect performance data, to audit performance data and to analyse the data. Absent these authorities and resources incentive regulation mechanisms will not achieve their promise in practice".[76]

129. Similarly Jamasb and Pollitt (2000) conclude:

> "It is important that regulators collect national and international data through formal co-operation and exchange. New regulators need to pay ample attention to developing good data collection and reporting systems. [Regulators should] focus on improving the quality of data collection processes, auditing and standardisation within and across countries"[77]

130. The Utility Regulators' Forum already has a work programme underway engaged in collecting performance information in a standardised, comparable manner. It is recommended that this work continue:

"(a) Regulators continue to collect standardised and comparable information on the performance of regulated companies in a manner which is useful for relative performance evaluation."

131. Having collected the productivity information, how should it be used and what weight should be given to it in the optimal regulatory contract? As we have seen, this depends on the nature of the information that can be gleaned from the data which, in turn depends on factors such as the extent to which the cost out-turns of different firms are correlated. Analysis of the data

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[75] See ACCC (2004a), Joskow (2005) comments: "Ideally, a comprehensive incentive regulation mechanism that consistently integrates all cost and quality relationships at a point and time over time would be applied. However, as a practical matter this often places very challenging information and implementation burdens on the regulator. Partial mechanisms or a portfolio of only loosely harmonised mechanisms are often used by regulators. Operating and capital cost norms and targets are typically developed separately and the effective power of the incentive scheme applicable to operating and capital costs may vary between them. Separate incentive mechanisms may be applied to measures of quality than to measures of total operating and capital costs. This reality represents perhaps the most significant variation between received incentive regulation theory and incentive regulation in practice". Page 30.

[76] Joskow (2005), page 83.

[77] Jamasb and Pollitt (2000), page 29.

therefore, is necessary in order to understand precisely what can be learned about the performance of any one firm by comparing it with others. It is recommended that a work programme be established to carry out this task:

“(b) That, as a first step, work be carried out to better understand the key cost drivers for electricity distribution businesses, the nature of the cost function of distribution businesses, the best approaches to comparing productivity and/or efficiency across firms and the reliability of those approaches.

(c) That, as a second step, work be carried out to understand the information content of relative productivity information of firms in different sectors. This work would seek to understand how the costs of different transmission and distribution businesses vary over time and relative to each other, and the extent to which different firms are subject to common cost, technology, or demand shocks.”

132. Once we have determined that relevant information can be obtained by comparing the performance of different firms, we need to figure out how to incorporate this information in the regulatory contract. This involves making decisions about the trade-off between the power of the incentives and the risk and/or rent left to the regulated firm. It might be possible to obtain some insights into the trade-offs involved through explicit modelling of the behaviour of different firms under different regulatory regimes, ideally using assumptions which are consistent with the observed performance out-turns collected and analysed in the recommendations above.

133. Modelling work of this form is inevitably no better than the assumptions of the model used. There are likely to be a number of different approaches which could appear to be consistent with the observed pattern of data. It would not be wise to place too much weight on the predictions of such models. However, such modelling might give the regulator a degree confidence as to the likely consequences of a given approach before putting it into practice.

“(d) As a third step, modelling work be carried out which would assist in understanding the trade-off between the power of incentives and either risk or rent-extraction that would have arisen under different regulatory mechanisms using the observed patterns of productivity changes which have arisen in the past.”

134. In any case, regulation is likely to continue to be at least in part a process of trial and error as regulators adjust or fine-tune their regulatory regimes, and learn how firms respond.[78] Until experience is gained in the use of relative performance evaluation, it seems wise to continue to give some weight to other sources of information – including information on regulated firm’s own cost out-turns.[79]

135. In summary, gathering and processing information is at the heart of the task of the regulator. Although the role of productivity information in creating efficient incentives on

[78] Joskow (2005), page 81: “Incentive regulation in practice is clearly an evolutionary process. One set of mechanisms is tried, their performance assessed, additional data and reporting needs identified, and refined mechanisms developed and applied. This type of evolutionary process seems to me to be inevitable”.

[79] Jamasb and Pollitt (2000), page 30, write: “benchmarking methods and their raw results should not be regarded as replacements to decision-makers and their judgements. Rather, the primary function of benchmarking methods is to serve as decision-aid tools that can help decision-makers overcome bounded rationality in a complex decision environment. Therefore, as in any area of public policy, regulatory decisions should ultimately be based on decision-makers’ judgements and discretion”.

regulated firms has been misunderstood, it is likely that relative productivity information will play some role in an optimal regulatory mechanism in the future, especially in those industries with a large number of comparable firms.

Appendix: The Theory of Incentive Regulation

136. In the economics literature there are two broad strands to the literature on optimal regulation in the presence of asymmetric regulation. These two broad strands differ in the assumptions about the nature of the uncertainty – specifically they differ in the assumptions they make about the information available to the regulated firm at the time it signs the regulatory contract. In both strands of the literature the cost (or productivity) of the regulated firm depends on the effort exerted by the management of the regulated firm to reduce expenditure. The observed cost out-turn is therefore the result of both the firm's "underlying" cost and the effort exerted by management of the regulated firm.

137. In one strand of the literature the firm does not know its "underlying" cost until after it has signed the regulatory contract. These models are known as "hidden action" or "principal-agent" models. In the other strand of the literature the firm knows its "underlying" cost at the time it signs the regulator contract. These models are known as "hidden information" or "adverse selection" models.

138. The two different types of models have quite different policy implications. A key implication of the adverse selection models is that it is usually optimal for the regulator to offer a menu of regulatory contracts to the regulated firm. The firm's choice between these contracts reveals something about its own underlying cost. In these models, the key trade-off is between the power of the incentive, on the one hand, and extracting the monopoly profit, on the other. A high-powered incentive will induce a high level of effort by the regulated firm, but will require that the firm be allowed to keep some monopoly rent on average (so that even if the firm turns out to be inefficient it will still be able to earn a normal rate of return).

139. In the principal-agent approach, the key trade-off is between the power of the incentive, on the one hand, and the extent to which the regulated firm is exposed to risk (or, conversely, is insured). Risk only matters when the regulated firm is risk-averse. Therefore this model requires the assumption that the regulated firm is risk-averse. In this model, higher-powered incentives induce a high level of effort by the regulated firm, but at the cost of exposing the regulated firm to higher levels of risk.

140. Both approaches have their strengths and weaknesses. The adverse selection approach captures the idea that the regulated firm may have some private information at the start of the regulatory period, but these models tend to be mathematically complex and their primary prediction – that it is optimal to offer a menu of regulatory contracts – is seldom observed in practice. The principal-agent approach, on the other hand, tends to be mathematically simpler. It is easier to generalise or vary the models to address different circumstances. On the other hand, these models rely on the assumption of risk aversion which is somewhat questionable. For more information on these two approaches to utility regulation, see the survey articles by Cowan (2002) and Chong (2004).

The Adverse Selection Approach

141. As a simple introduction to the adverse selection approach, consider the following model based on the example used in Cowan (2002). This model is simplified in that it assumes that (a) the regulator can only offer a single linear contract to the regulated firm and (b) the cost of effort

is quadratic, so that the marginal cost of effort is constant. In fact we know that in adverse selection models it will usually not be optimal for the regulator to offer a single regulatory contract, but a menu of regulatory contracts, but this model illustrates many of the important features.

142. Let's assume that we have a firm which produces a single unit of some good. Under the conventional approach it is assumed that the observed (or "accounting") cost of the regulated firm is equal to an underlying parameter θ less the effort e exerted by the firm in reducing its costs. The observed cost of the regulated firm is therefore $\theta - e$. The firm knows the value of θ at the time when it must sign the regulatory contract. The regulator does not know the value of θ but knows that θ lies in the range $[\underline{\theta}, \overline{\theta}]$ with the mean $E[\theta]$.

143. The regulator is assumed to offer the regulated firm a simple linear contract under which the price paid for the output of the regulated firm depends on the observed cost $\theta - e$ in the form $p = a + (1-b)(\theta - e)$, where *a* and *b* are parameters determined by the regulator.

144. The profit of the firm is equal to the firm's revenue less its observed cost less the cost of effort which takes the form $\frac{\phi e^2}{2}$. The firm's profit is therefore:

$$\pi(a,b,\theta,e) = p - (\theta - e) - \frac{\phi e^2}{2} = a - b(\theta - e) - \frac{\phi e^2}{2} \qquad \ldots(1)$$

145. As noted in Biggar (2004) we can define the power of the incentive to reduce expenditure as the sensitivity of the firm's profit to the observed cost which, in this case is just *b*. $b = 0$ corresponds to a very low powered incentive (i.e., rate of return regulation where as $b = 1$ corresponds to a very high powered incentive (i.e., price cap or "fixed price" regulation).

146. In this model, the regulated firm will choose the level of effort which maximises equation (1). This is given by $e(\theta) = \frac{b}{\phi}$. Clearly, higher powered incentives induce higher levels of effort.

147. The regulator must ensure that the regulated firm will accept the regulatory contract no matter what its underlying cost. This means that $\pi(a,b,\theta,e(\theta)) = a - b(\theta - \frac{b}{\phi}) - \frac{b^2}{2\phi} = a - b\theta + \frac{b^2}{2\phi} \geq 0$ for all values of θ, which implies that: $a = b\overline{\theta} - \frac{b^2}{2\phi}$.

148. The regulator wants to choose the value of *a* and *b* which maximises overall welfare. The overall welfare is assumed to be equal to consumers' surplus plus producers' surplus except that the producers' surplus is given the weight α which (as we will see) is less than one to reflect the fact that rent left to the regulated firm induces a welfare loss through allocative inefficiency which is not modelled here.

149. Consumers are assumed to receive a gross utility of *U* from consuming the regulated good. The overall welfare is then:

$$W(a,b) = (U - p) + \alpha\pi = U - a + (1-b)(E[\theta] - e) + \alpha(a - b(E[\theta] - e) - \frac{\phi e^2}{2})$$

$$= U - (1-\alpha)a + (1-(1-\alpha)b)(E[\theta] - e) - \frac{\alpha\phi e^2}{2}$$

150. This is maximised by choosing $b = 1 - \phi(1-\alpha)(\overline{\theta} - E[\theta])$. In other words, the optimal power of the incentive depends on:

(a) The degree of uncertainty in the firm's underlying cost (represented by the expression $\overline{\theta} - E[\theta]$). The greater the uncertainty the lower the optimal power of the incentive scheme.

(b) The firm's cost of exerting effort to reduce its cost (represented by the parameter ϕ). The higher the marginal cost of effort the lower the optimal power of the incentive scheme.

(c) The social welfare cost of allowing excess monopoly profit (represented by the parameter $1-\alpha$). The higher the cost of allowing excess monopoly profit, the lower the optimal power of the incentive scheme.

The Principal-Agent Approach

151. Let's consider the same basic structure as in the previous example but this time in the context of a principal-agent model. Let's assume that the regulated firm is risk-averse. To keep things simple, let's assume that the firm's objective function depends only on the mean and variance of its observed profit. Specifically, let's assume that the firm's objective function is given as:

$$E\pi - \frac{\gamma}{2} Var\pi - \frac{\phi e^2}{2}$$

152. As before, the regulator offers a regulated price which is a linear function of the observed cost $\theta - e$, equal to $p = a + (1-b)(\theta - e)$, so the firm's observed (accounting) profit is, as before, $\pi = a - b(\theta - e)$. The objective function of the regulated firm is therefore:

$a - b(E[\theta] - e) - \frac{\gamma b^2 \sigma^2}{2} - \frac{\phi e^2}{2}$ where σ^2 is the variance of θ.

153. The firm chooses the level of effort *e* to maximise this expression, which yields, as before $e(\theta) = \frac{b}{\phi}$. The firm must be given at least zero profit on average so we have that: $a - b(E[\theta] - e) - \frac{\gamma^2 b^2 \sigma^2}{2} - \frac{\phi e^2}{2} = a - bE[\theta] - \frac{\gamma^2 b^2 \sigma^2}{2} - \frac{b^2}{2\phi} = 0$.

154. The overall expected welfare is, as before, a weighted average of producers' surplus and consumers' surplus.

$$EW(a,b) = E[(U - p) + \alpha\pi] = U - a + (1-b)(E[\theta]-e) + \alpha(a - b(E[\theta]-e) - \frac{\gamma b^2 \sigma^2}{2} - \frac{\phi^2}{2})$$

155. This expression is maximised at $b = \frac{1}{1+\phi\gamma\sigma^2}$. In other words, the optimal power of the incentive depends on:

(a) The degree of uncertainty in the firm's underlying cost (represented by the expression σ^2). The greater the uncertainty the lower the optimal power of the incentive scheme.

(b) The firm's cost of exerting effort to reduce its cost (represented by the parameter ϕ). The higher the marginal cost of effort the lower the optimal power of the incentive scheme.

(c) The degree of risk-aversion of the regulated firm (represented by the parameter γ). The more risk averse is the regulated firm, the lower the optimal power of the incentive scheme.

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